WOLF CREEK
NUCLEAR OPERATING CORPORATION

Britt T. McKinney
Site Vice President

OCT 3 0 2003

WO 03-0057

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

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

Gentlemen:

Wolf Creek Nuclear Operating Corporation (WCNOC) hereby transmits an application for amendment to Facility Operating License No. NPF-42 for the Wolf Creek Generating Station (WCGS).

This amendment application would revise Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Times for the Required Actions associated with an inoperable diesel generator. This amendment application requests revision of TS 3.8.9, "Distribution Systems – Operating," to extend the Completion Time for one AC vital bus subsystem inoperable. These proposed changes are based on the methodology provided in WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times," and associated Industry/Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-417, Rev. 0.

The WCNOC Plant Safety Review Committee and the Nuclear Safety Review Committee have reviewed the changes being proposed in this amendment application. Attachments I through VI provide the Evaluation, Plant-Specific Information in Support of Responses to NRC Request for Additional Information Regarding WCAP-15622, Markup of Technical Specifications, Retyped Technical Specifications, Proposed Technical Specification Bases Changes, and List of Commitments, respectively, in support of this amendment request. Attachment V is provided for information only. Final Bases changes will be implemented pursuant to TS 5.5.14, "Technical Specifications (TS) Bases Control Program."

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As indicated in Attachment I, the proposed TS changes have been evaluated pursuant to CFR 50.92, and it has been determined that this amendment application does not involve a *significant hazard consideration*. In addition, evaluation of the proposed changes against the requirements of 10 CFR 51.22(b) has determined that no environmental impact statement or environmental assessment needs to be prepared in connection with the issuance of a license amendment for the proposed changes. The bases for these determinations are included in the Attachments. WCNOC's evaluation includes traditional engineering analyses as well as a risk-informed approach as set forth in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

WCNOC is submitting this license amendment request (LAR) in conjunction with an industry consortium of six plants as a result of a mutual agreement known as Strategic Teaming and Resource Sharing (STARS). The STARS group consists of the six plants operated by TXU Generation Company LP, Union Electric Company, WCNOC, Pacific Gas and Electric Company, STP Nuclear Operating Company, and Arizona Public Service Company. Other members of the group are expected to submit LARs similar to this one. Due to design differences between the STARS plants, there may be some differences in the plant LARs, particularly for the information provided in Attachment I.

The proposed changes may affect the scheduling of DG maintenance and testing activities, including which activities are to be performed during plant operation and which are to be performed during refueling outages. The changes could therefore affect the scheduling of activities for the 14th refueling outage, which is scheduled for March of 2005. On this basis, WCNOC requests approval of the proposed license amendment by August 2, 2004. Once approved, this amendment will be implemented within 90 days.

In accordance with 10 CFR 50.91, a copy of this application, with attachments, is being provided to the designated Kansas State Official. If you should have any questions regarding this submittal, please contact me at (620) 364-4112, or Mr. Kevin Moles, Manager Regulatory Affairs, at (620) 364-4126.

Sincerely,

Britt T. McKinney

Britt T. McKinney

BTM/rlg

Attachments:
- I - Evaluation
- II - Plant-Specific Information in Support of Responses to NRC Request for Additional Information Regarding WCAP-15622
- III - Marked-Up Technical Specifications
- IV - Proposed/Revised Technical Specifications
- V - TS Bases Changes (For Information Only)
- VI List of Commitments

cc: V. L. Cooper (KDHE), w/a
J. N. Donohew (NRC), w/a
D. N. Graves (NRC), w/a
B. S. Mallett (NRC), w/a
Senior Resident Inspector (NRC), w/a

STATE OF KANSAS)
) SS
COUNTY OF COFFEY)

Britt T. McKinney, of lawful age, being first duly sworn upon oath says that he is Site Vice President 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 Britt T. McKinney
Britt T. McKinney
Site Vice President

SUBSCRIBED and sworn to before me this 30TH day of Oct, 2003.

Mary E. Gifford
Notary Public

MARY E. GIFFORD
Notary Public - State of Kansas
My Appt. Expires 12/09/2003

Expiration Date 12/09/2003

EVALUATION

1.0 DESCRIPTION

Technical Specification 3.8.1, "AC Sources – Operating," specifies OPERABILITY requirements for the onsite and offsite AC electrical power sources. Included in the TS are the Required Actions to be taken when a source(s) is declared inoperable. In particular, with one diesel generator (DG) inoperable, Condition B applies so that it's associated Required Actions must be entered and met. This includes restoring the inoperable DG to OPERABLE status in accordance with Required Action B.4.

Required Action B.4 requires restoring the inoperable DG to OPERABLE status within a specified Completion Time which may also be referred to as the allowed outage time (AOT). If the inoperable DG is not or cannot be restored within the specified Completion Time of 72 hours, Condition G must be entered, which requires the plant to be in MODE 3 within 6 hours and in MODE 5 within 36 hours. The principal, proposed change to Required Action B.4 is to provide an alternative Completion Time in the form of a Note, that permits an extended DG Completion Time of 7 days, in comparison to the single Completion Time of 72 hours currently specified in Required Action B.4. This increased AOT or Completion Time would be applicable only on a once per cycle basis for each DG, and would be applicable only for the performance of voluntary, planned maintenance activities, as further described in Subsections 2.0 and 4.1 of this Attachment. The existing 72-hour Completion Time would still be retained and would apply in the same manner as it currently applies. Thus, there would be two Completion Times specified for Required Action B.4 such that either the existing 72-hour Completion Time would apply or the extended 7-day Completion Time as specified by the Note would apply (subject to the applicable provisions), depending on the circumstances for entering Condition B.

Technical Specification 3.8.9, "Distribution Systems – Operating," specifies OPERABILITY requirements for the AC, DC, and AC vital bus distribution systems. Included in the TS are the Required Actions to be taken when one AC vital bus subsystem is declared inoperable. With one AC vital bus subsystem inoperable, Condition C is entered and Required Action C.1 requires restoring the AC vital bus subsystem to OPERABLE status within the specified Completion Time of 2 hours. The principal, proposed change to Required Action C.1 permits an extended AC vital bus subsystem Completion Time of 24 hours.

The proposed DG Completion Time extension (from 72 hours to 7 days) and the proposed AC vital bus subsystem Completion Time extension (from 2 hours to 24 hours) is based on the methodology provided in Westinghouse Owners Group (WOG) Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times," (Reference 1), and associated Industry/Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-417, Rev. 0, (Reference 2).

2.0 PROPOSED CHANGES

The specific changes to the WCGS TSs for each of the changes described above are identified as follows:

LCO 3.8.1, Electrical Power Systems, AC Sources – Operating; Condition B, One DG inoperable

- A Note is added to the Completion Time for Required Action B.4, Restore DG to OPERABLE status, to allow an increased Completion Time. The Note states: "A Completion Time of 7 days and 10 days from discovery of failure to meet LCO may be used once per cycle per DG."

This Note to the Completion Time(s) means that only one of the two Completion Times applies at a time, i.e., either the 7-day Completion Time which is allowed only once per cycle for each DG (as analyzed per the methodology of WCAP-15622 to support on-line maintenance under the extended DG Completion Time) or the retained 72-hour Completion Time which applies in the same manner that it currently applies. This change is further explained and justified in Subsection 4.1.

- A Note is added to the Completion Time for Required Action A.3, Restore offsite circuit to OPERABLE status, to account for the Note added to the Completion Time of Required Action B.4. The Note states: "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 for an inoperable DG."

LCO 3.8.9, Electrical Power Systems, Distribution Systems – Operating Condition C, One AC vital bus inoperable

- The Completion Time for Required Action C.1, Restore AC vital bus subsystem to OPERABLE status, is revised to increase the Completion Time from "2 hours" to "24 hours."

- The second Completion Time in Required Actions B.1, C.1, and D.1, are revised from "16 hours from discovery of failure to meet LCO" to "34 hours from discovery of failure to meet LCO."

The marked-up and revised TS pages reflecting the above changes are provided in Attachments III and IV respectively. In addition, the associated TS Bases will be revised to reflect the changes to these TS. A marked-up copy of the proposed TS Bases changes is provided in Attachment V for information only. The TS Bases changes will be implemented in accordance with TS 5.5.14, "Technical Specifications (TS) Bases Control Program," as part of the implementation of this amendment after NRC approval.

3.0 BACKGROUND

Background information for supporting review of the proposed AC Electrical Power Systems Completion Time extension is provided in Subsection 3.1 below. This includes a description of the Class 1E AC power system at WCGS (Subsection 3.1.1), information concerning the development and applicability of WCAP-15622 and TSTF-417 (Subsection 3.1.2), and identification of another license amendment request from WCNOC that is related to this request (Subsection 3.1.3). Background information related to the proposed changes to the second Completion Times is provided in Subsection 3.2.

3.1 Extension of AC Electrical Power System Completion Times

3.1.1 Description of Class 1E Power System at WCGS

The onsite power system for WCGS is provided with preferred power from an offsite power source in accordance with 10 CFR 50, Appendix A, General Design Criterion (GDC) 17, GDC 18, and Regulatory Guide 1.32. Offsite power is supplied to the unit switchyard from the transmission network by three transmission lines. With respect to the safety related (Class 1E) power supply configuration, one preferred circuit from the switchyard supplies power to a multi-winding startup transformer, one winding of which feeds a 13.8/4.16-kV engineered safety features (ESF) transformer. The second preferred (offsite) circuit supplies power from the switchyard to the second 13.8/4.16-kV ESF transformer. Each ESF transformer supplies power to an associated Class 1E 4.16-kV bus. For each safety related bus normally fed by its associated ESF transformer, the capability exists for either bus to be ultimately supplied via the other preferred source connection. Each offsite power circuit can be manually aligned to supply power to the opposite or both 4.16-kV busses, if required.

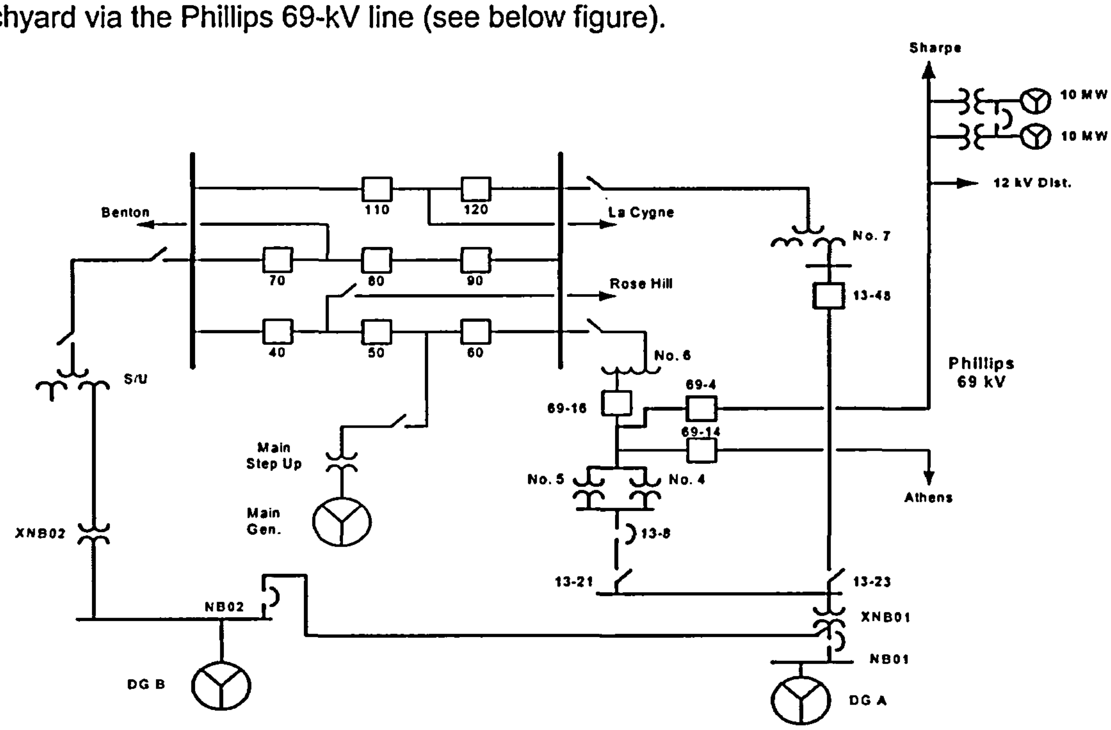
The onsite power system is generally divided into two load groups. Each load group consists of an arrangement of buses, transformers, switching equipment, and loads fed from a common power supply. Power is supplied to loads at 13.8 kV, 4.16 kV, 480 V, 480/277 V, 208/120 V, 120 VAC, 250 VDC, and 125 VDC. The Class 1E AC system loads are accordingly separated into two load groups which, as noted above, are powered from separate ESF transformers. Each load group has power distributed by a 4.16-kV bus (NB01 or NB02), 480-V load centers, and 480-V motor control centers. Each load group is independently capable of safely bringing the plant to a cold shutdown condition, as the Class 1E electrical power distribution system is designed to satisfy the single-failure criterion.

The onsite standby power system includes Class 1E AC and DC power supply capability for equipment used to achieve and maintain a cold shutdown of the plant and to mitigate the consequences of a design basis accident (DBA). With respect to Class 1E AC power, each of the two Class 1E load groups, at the 4.16-kV bus level, is capable of being powered from an independent DG (one per load group) which functions to provide power in the event of a loss of the preferred power source. Undervoltage relays are provided for each 4.16-kV bus to detect an undervoltage condition and automatically start the DG in response to such a condition. The Class 1E DC system includes four separate 125-VDC battery supplies for Class 1E controls, instrumentation, power, and control inverters.

A simplified one-line diagram of the electrical power distribution system described above is provided on Figure 1 on the next page (i.e., page 5 of 27). As can be seen from the figure, and as described above, each of the two 4.16-kV Class 1E buses is normally supplied by its preferred (offsite) power source (via its respective ESF transformer) and is capable of being exclusively supplied by its associated DG (as there is no automatic connection between the redundant load groups.)

In the event of a loss-of-coolant accident (LOCA) and/or loss of offsite power, the starting (or shedding and restarting) of Class 1E electrical loads is controlled by the load shedder emergency load sequencers (LSELS) (one for each 4.16 kV bus). In the event of a LOCA with preferred (offsite) power available to the 4.16-KV Class 1E bus(es), Class 1E loads are started in programmed time increments by the load sequencer(s). The associated DG(s) will be automatically started but not connected to the bus. However, in the event that preferred (offsite) power is lost, the load sequencer will function to shed selected loads and automatically start the associated standby DG (via the DG control circuitry). The load sequencer(s) will function to start the required Class 1E loads in programmed time increments.

In 2002, Kansas Electric Power Cooperative, Inc. (KEPCo) constructed an electric generating station (Sharpe Station) that consists of ten, two-megawatt Caterpillar 3516B engine-generator sets (gensets). The gensets are sited at a single location near an existing 69 kV substation near Sharpe, Kansas, approximately two miles north of WCGS. Siting it near WCGS provides emergency back-up power for WCGS, specifically, to improve availability and reliability of sufficient AC power for planned or postulated WCGS plant conditions including planned onsite DG maintenance, emergent failure of one onsite DG, complete loss of all onsite emergency AC power, and grid perturbations or loss of a normal offsite power source to WCGS. Currently, Sharpe Station is not an Alternate AC (AAC) power source as defined in Regulatory Guide 1.155, "Station Blackout," (Reference 4) Power from the Sharpe Station enters the WCGS switchyard via the Phillips 69-kV line (see below figure).



Simplified One-Line Diagram of Sharpe Station Power to WCGS

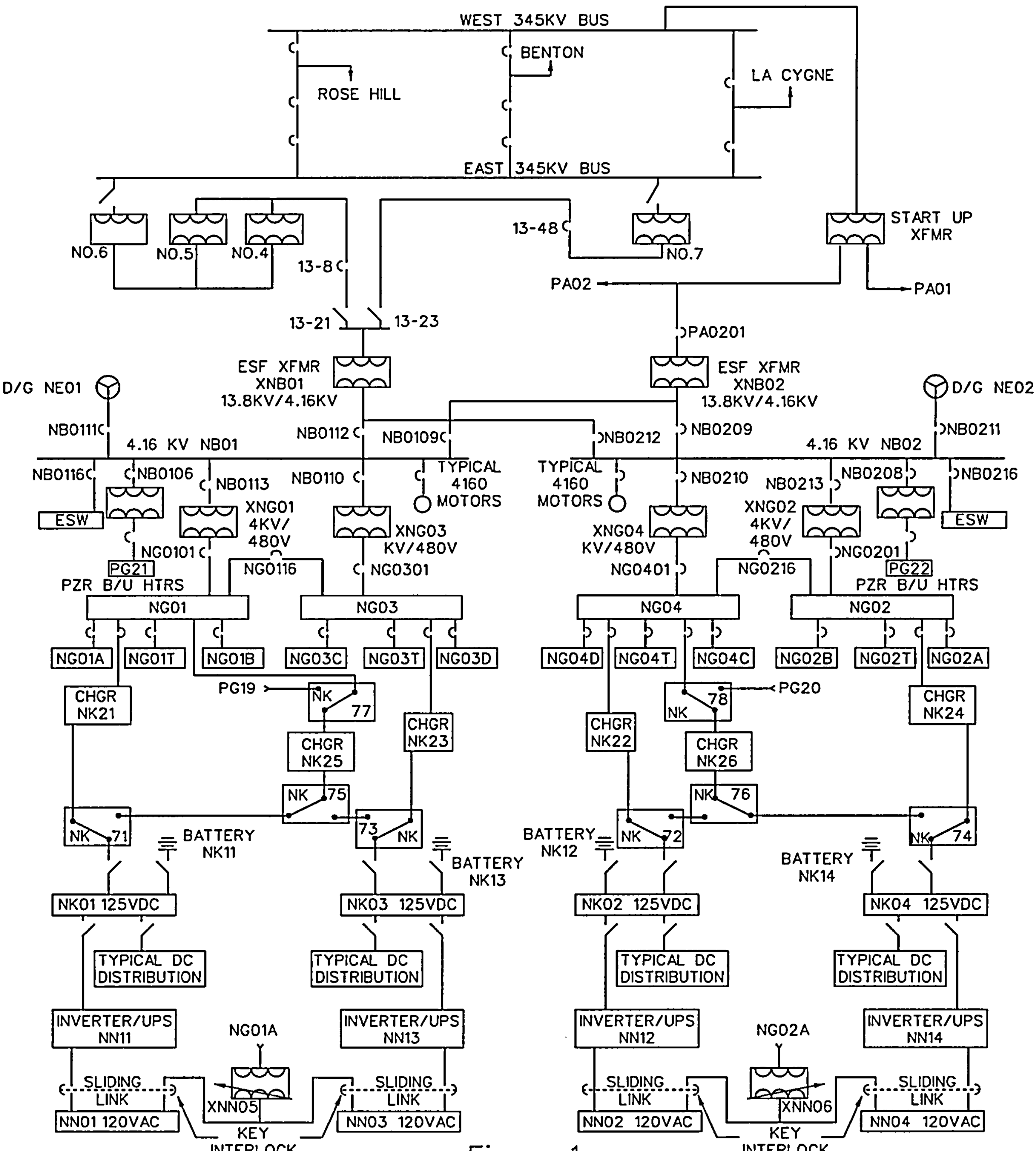

WEST 345KV BUS
BENTON
ROSE HILL
LA CYGNE
EAST 345KV BUS
NO.6
NO.5
NO.4
13-8
13-48
NO.7
START UP XFMR
PA02
PA01
13-21
13-23
PA0201
ESF XFMR XNB01 13.8KV/4.16KV
ESF XFMR XNB02 13.8KV/4.16KV
D/G NE01
D/G NE02
NB0111
4.16 KV NB01
NB0112
NB0109
NB0212
NB0209
4.16 KV NB02
NB0211
NB0116
NB0106
NB0113
NB0110
TYPICAL 4160 MOTORS
TYPICAL 4160 MOTORS
NB0210
NB0213
NB0208
NB0216
ESW
XNG01 4KV/480V
XNG03 KV/480V
XNG04 KV/480V
XNG02 4KV/480V
ESW
NG0101
NG0116
NG0301
NG0401
NG0216
NG0201
PG21
PG22
PZR B/U HTRS
PZR B/U HTRS
NG01
NG03
NG04
NG02
NG01A
NG01T
NG01B
NG03C
NG03T
NG03D
NG04D
NG04T
NG04C
NG02B
NG02T
NG02A
PG19
NK 77
PG20
NK 78
CHGR NK21
CHGR NK25
CHGR NK23
CHGR NK22
CHGR NK26
CHGR NK24
NK 75
NK 76
NK 71
73 NK
NK 72
NK 74
BATTERY NK11
BATTERY NK13
BATTERY NK12
BATTERY NK14
NK01 125VDC
NK03 125VDC
NK02 125VDC
NK04 125VDC
TYPICAL DC DISTRIBUTION
TYPICAL DC DISTRIBUTION
TYPICAL DC DISTRIBUTION
TYPICAL DC DISTRIBUTION
INVERTER/UPS NN11
INVERTER/UPS NN13
INVERTER/UPS NN12
INVERTER/UPS NN14
NG01A
NG02A
SLIDING LINK
SLIDING LINK
SLIDING LINK
SLIDING LINK
XNN05
XNN06
NN01 120VAC
NN03 120VAC
NN02 120VAC
NN04 120VAC
KEY INTERLOCK
KEY INTERLOCK

Figure 1

3.1.2 WCAP-15622 Program and TSTF-417

Topical Report WCAP-15622 evaluates several AC electrical power system Standard Technical Specification Completion Time changes as part of a larger program considering changes to a number of Standard Technical Specification Completion Times. The purpose of WCAP-15622 is to provide the technical justification for extending the Completion Times for the following specifications (based on the Improved Standard Technical Specifications, NUREG-1431, Rev. 2):

LCO 3.8.1, Electrical Power Systems, AC Sources - Operating; Required Actions B.3.1 or B.3.2

LCO 3.8.1, Electrical Power Systems, AC Sources - Operating; Required Action B.4

LCO 3.8.9, Electrical Power Systems, Distribution Systems - Operating; Required Action B.1

This effort was motivated by the recognition that current Completion Times specified in the TSs are, in some cases, insufficient to respond to OPERABILITY problems and perform maintenance activities at power. It was recognized that, through probabilistic risk assessment, a more risk-informed approach could be taken to justify more appropriate, extended Completion Times.

Although a WOG program was established for this effort, it was recognized that plant-specific evaluations would be needed. The thrust of the WOG program was to develop a common methodology and establish a means for providing cross comparisons between plant-specific results and designs. WCAP-15622 was developed from this effort, and is the topical report prepared specifically for evaluating Completion Time extensions for AC electrical power systems, including the standby/emergency DGs. The approach taken (for this and other topical reports prepared for Completion Time extensions) is consistent with the NRC's approach for using probabilistic risk assessment in making risk-informed decisions with regard to plant-specific changes to the current licensing basis. This approach is discussed in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," (Reference 9) and (with particular regard to Completion Time extensions) in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," (Reference 10).

Following submittal of WCAP-15622 (Rev. 0) to the NRC in June 2001 (Reference 5), the NRC staff issued two requests for additional information (RAIs) (References 6 and 7) in January 2002 regarding the topical report. Responses to both of the NRC's RAI letter were subsequently provided by the WOG via letter OG-02-052, dated November 27, 2002 (Reference 8).

In the WOG's response to the NRC requests, each individual request or question contained in the NRC's letters was assigned an RAI number, and the RAIs were categorized into groups based the subject and type of response required. It was identified that some of the RAIs would require plant-specific responses or additional plant-specific information, and that the participating plants/utilities would provide this information in their individual LARs. Accordingly, responses and information specific to WCNOC are provided in Attachment II of this LAR.

3.1.3 Related License Amendment Request

By letter WO 03-0009 (Reference 11) dated April 30, 2003, WCNOC submitted a LAR that also revises TSs related to the DGs. The changes proposed by that LAR, which is currently under review by the NRC staff, would eliminate or modify the MODE restrictions that are currently imposed on many of the Surveillance Requirements (SRs) specified in the TSs for the DGs.

As described in Attachment I to WO 03-0009, the testing monitoring and inspection activities required by all of the various SRs specified under TS 3.8.1 for the DGs are required to be performed on a periodic basis, but in some cases they may also be performed to verify or re-establish DG OPERABILITY following repairs or other unanticipated corrective maintenance. Under the current TSs, testing per some of the DG SRs is allowed to be performed during any plant MODE; however, many of the SRs contain the provision, in the form of a Note included with each affected SR, that the surveillance is not to be performed during certain plant MODES (in most cases, during plant operation). The changes proposed in letter WO 03-0009 would modify such MODE restrictions by revising or removing the Note associated with each applicable SR to either completely remove the MODE restrictions for the affected surveillance, or conditionally allow the surveillance to be performed (or partially performed) during currently prohibited MODES following corrective maintenance.

Two types of changes are thus proposed per WO 03-0009:

1. The MODE 1 and 2 restrictions currently specified for the following SRs would be completely removed: SR 3.8.1.10 (full load rejection test), SR 3.8.1.13 (protective-trip bypass test), and SR 3.8.1.14 (endurance and margin test). The changes would thus allow these DG surveillances to be performed periodically and/or following planned or unplanned maintenance, during any plant MODE.

2. For the remaining applicable DG SRs, the associated Notes that currently impose MODE restrictions would be modified to allow performance or partial performance of the affected surveillances during plant operation but only in order to re-establish OPERABILITY following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, or other unanticipated OPERABILITY concerns during plant operation. The DG SRs affected by these changes are as follows: SR 3.8.1.11 (loss-of-offsite-power test), SR 3.8.1.12 (safety injection actuation signal test), SR 3.8.1.16 (synchronizing test), SR 3.8.1.17 (test mode change-over test), SR 3.8.1.18 (load sequencing test), and SR 3.8.1.19 (combined safety injection actuation signal and loss-of-offsite-power test). These changes are being proposed consistent with NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-283, Revision 3.

The above changes are similar, the main difference being that the allowance for performing the affected SRs during plant operation would be conditional for the second set of changes, while it would be unconditional for the first set. In effect, the changes would permit SRs 3.8.1.10, 3.8.1.13, and 3.8.1.14 to be scheduled for routine performance (or to be performed for post-maintenance testing) during plant operation. The remaining affected SRs would continue to be scheduled for their routine performance during plant outages, except that they could be considered for performance (or partial performance) during plant operation if required to verify DG OPERABILITY following unanticipated corrective maintenance.

In other words, by removing the MODE restrictions that completely prohibit the performance of the affected SRs during plant operation, the change proposed per WO 03-0009 provides the flexibility to schedule a surveillance test like SR 3.8.1.14 for its routine performance during plant operation, or to perform such a surveillance for verifying OPERABILITY following on-line maintenance. Thus, although the scheduled performance of a routine surveillance (on-line) would most likely continue to be performed under the 72-hour Completion Time of Required Action B.4, the proposed, extended DG Completion Time provides additional time for including the performance of SRs (on-line) that may be needed for post-maintenance testing in the time period scheduled for on-line maintenance. In this regard, the proposed DG Completion Time change is supported by the change proposed in WO 03-0009.

Letter WO 03-0009 also provides additional information and details regarding the design and operation of the DGs at WCGS, including a description of how testing that would be allowed to be conducted during plant operation is expected to be conducted and how a DG would respond to an emergency demand or a protective trip during the performance of such testing.

3.2 Changes to Second Completion Times

Topical Report WCAP-15622 was submitted to the NRC for review in June 2001. The topical report justifies extending the Completion Times for certain AC electrical power systems/components, based on plant-specific probabilistic risk analysis. As such, the extended Completion Times are based on a risk-informed approach. This is in contrast to the generic Completion Times currently specified in the Improved Standard Technical Specifications, which are deterministically based, i.e., based primarily on engineering judgment including, for example, consideration of the OPERABILITY of redundant systems, trains or components and qualitative consideration of the low probability of an event occurring while the Completion Time is in effect.

Most of the Required Actions affected by the WCAP-supported Completion Time extensions each contain a second Completion Time for limiting the overall time that the associated LCO may not be met from initial entry into a Condition. These second Completion Times must be considered when extending a component or system Completion Time. Extending the component or system Completion Time necessitates revising the second Completion Times since the second Completion could be more limiting than the extended Completion Time and thus would negate the effect of the extended Completion Time.

WCAP-15622 and the corresponding TSTF-417, proposed to extend the second Completion Time (to accommodate the extended Completion Time) by adding the individual Completion Times associated with the affected Required Actions which includes the extended Completion Times. The NRC transmitted a letter to NEI in November 2001 discussing a staff concern identified during their review of Topical Reports WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (TSTF-417) and CE NSPD-1045, "Joint Applications Report, Modification to the Containment Spray System, and the Low Pressure Safety Injection System Technical Specifications" (TSTF-409). Specifically, the NRC indicated that increases in the Improved Standard Technical Specification Completion Time limits by adding together risk-informed and deterministic values using engineering judgment would not be approved. In subsequent discussions with the NRC in September, 2003, the NRC indicated it was acceptable to increase the second Completion Time by adding together risk-informed and deterministic values. This is further discussed in Subsection 4.2.

4.0 TECHNICAL ANALYSES

4.1 Extension of AC Electrical Power System Completion Times

4.1.1 Assessment of Impact on Risk

The methodology for this technical justification is consistent with the NRC approach for using probabilistic risk assessment (PRA) in risk-informed decisions on plant–specific changes to the current licensing basis. The risk evaluation considers the three-tiered approach as presented by the NRC in Regulatory Guide 1.177. Tier 1, PRA Capability and Insights, assessed the impact of the proposed Completion Time change on core damage frequency and incremental conditional core damage probability as well as large early release frequency and incremental conditional large early release probability. Tier 2, Avoidance of Risk-Significant Plant Configurations, considered potential risk-significant plant operating configurations during the condition in question. Tier 3, Risk-Informed Plant Configuration Control and Management is implemented consistent with the Maintenance Rule program.

Discussion of the methodology is described at greater length in the Westinghouse approach described in WCAP-15622. Westinghouse, with the input of several plants, submitted a methodology, via WCAP-15622, for extension of specific electrical power system TS Completion Times. WCAP-15622 is, in essence, a Regulatory Guide 1.177 risk-informed approach to this end. Regulatory Guide 1.177 defines specific risk criteria for change in Core Damage Frequency (CDF) and Incremental Conditional Core Damage Probability (ICCDP) to which changes to the TS should be gauged. Regulatory Guide 1.174, is also pertinent to permanent TS Completion Time changes. As such, it describes a "very small" increase in CDF as less than 1.0E-06, which demands consideration by the NRC. The NRC, however, will only consider an increase in CDF between 1.0E-06 and 1.0E-05 if it can be reasonably shown that the total CDF is less than 1.0E-04. Therefore, an increase in CDF of 1.0E-06 becomes the threshold risk criteria previously discussed.

The methodology is in accordance with the criteria set forth in Regulatory Guide 1.174 and Regulatory Guide 1.177.

The criteria are summarized here.

Reg.Guide	Criteria	Label	Per Reactor Year
1.174	Core Damage Frequency	CDF	< 1E-04
1.174	Change in Core Damage Frequency	ΔCDF	< 1E-06
1.174	Large Early Release Frequency	LERF	< 1E-05
1.174	Change in Large Early Release Frequency Increase	ΔLERF	< 1E-07
1.177	Incremental Conditional Core Damage Probability*	ICCDP	< 5E-07
1.177	Incremental Conditional Large Early Release Probability**	ICLERP	< 5E-08

* ICCDP = [(conditional CDF with the subject equipment out of service) – (baseline CDF with nominal expected equipment unavailabilities)] x duration of single Completion Time under consideration.

** ICLERP = [(conditional LERF CDF with the subject equipment out of service) – (baseline LERF with nominal expected equipment unavailabilities)] x duration of single Completion Time under consideration.

4.1.1.1 Tier 1: PRA Capability and Insights

Section 8.1 of WCAP-15622 provides a good discussion on the Tier 1 process. Briefly, the Tier 1 analysis provides the impact of the Completion Time changes on CDF and ICCDP. The primary impact of the Completion Time changes being considered is on CDF, the level 1 PRA measure. These changes do not independently impact containment systems, such as, containment cooling or sprays. That is, if a train of emergency AC power (DGs) is removed from service, the systems preventing containment failure are not impacted independent of the impact on the systems used to prevent core damage.

In several locations, a reference is made to additional information provided for a Request for Additional Information (RAI). These RAIs resulted from the NRC review process of the WCAP-15622. Attachment II contains the plant-specific responses as delineated in OG-02-052, "Westinghouse Owners Group Transmittal of RAI Responses for WCAP-15622, 'Risk-Informed Evaluation of Extensions To AC Electrical Power System Completion Times,'" dated November 27, 2002.

4.1.1.1.1 WCGS Probabilistic Safety Assessment (PSA) Model

The WCGS Level I internal events PSA model reflects the plant configuration (design and procedures) as of the end of 1998. Documentation for the model was completed in August 1999. Plant specific reliability and unavailability data values for major plant equipment reflect plant history through the end of 1994, with consideration of more recent component failure experience (through 1998). Due to resource limitations, the internal flooding evaluation was not included in the most recent PSA model update. The internal flooding evaluation was requantified in 1996 with one area flooding event added; but for the most part reflects plant configuration and data as utilized for the original PSA model developed for the Individual Plant Examination (IPE) (1992 submittal). The containment performance evaluation portion of the WCGS PSA model was developed for the IPE and has not been subject to an update. Implementation of the Safety Monitor™ at WCGS included development of a LERF top logic model (1997). A limited scope Shutdown modes PSA model was also developed as part of the development/implementation of the Scientech, Inc. Safety Monitor™ risk evaluation tool.

Changes to the model for this application are discussed in Subsection 4.1.1.1.5 and the response to RAI 2 in Attachment II.

4.1.1.1.2 PSA Model Development

Key milestones for the development of the WCGS PSA model are as follows:

Sept. 1992	Final comparison to the Callaway Plant PSA model under SNUPPs IPE
Sept. 1992	Original PSA (4.2E-05 CDF/rx yr) submitted in response to NRC Generic Letter 88-20 requirement to perform an IPE
Early 1995	Conversion from Westinghouse PSA Software to Scientech (NUS) PSA Software
June 1995	Individual Plant Examination of External Events (IPEEE) submitted to the NRC
July 1996	Response to NRC RAI on IPE resulted in July 1996 Quantification (6.3E-05 CDF/rx yr)
Nov. 1996	IPE Safety Evaluation Report (SER) received from the NRC
Dec. 1997	Implementation of the Safety Monitor™ at WCGS included development of a LERF top logic model
Feb. 1998	Self-Assessment to identify PSA weaknesses and guide update priorities
July 1998	Comprehensive PSA model '98 Update' (5.48E-05 CDF/rx yr)
Dec. 1999	Limited scope Shutdown modes PSA model developed as part of the Safety Monitor™ risk evaluation tool
Feb. 2000	IPEEE SER received from the NRC
Nov. 2001	WOG Peer Review report on WCGS PSA model issued
Aug. 2003	PSA model changes for proposed vital AC bus and DG Completion Time extension completed

4.1.1.1.3 1998 WCGS PSA Model Update Details

The 1998 model update was a comprehensive update and included significant changes and additions.

Notable Initiating Event Frequencies

Initiating Event / Frequency	IPE	1998 Update
Transient With Main Feedwater (MFW)	4.30	1.17
Transient Without MFW	0.19	0.17
Loss of Offsite Power	5.10E-02	2.84E-02
SGTR	1.10E-02	5.90E-03

(Changes based on Industry and WCGS plant-specific experience)

Computed Initiating Event Frequencies

Imported during final Quantification Process as Fault Tree Solution (cutset file)

- Loss of Component Cooling Water
- Loss of All Service Water
- Loss of 125 VDC Busses: NK01 and NK04

Allows impact of Component(s) Out-of-Service to be reflected in both the:

- Initiating Event Frequency
- Event Mitigation Probability

Event Tree Changes

- Event Trees changed to more readily accept Initiating Event cutset files and Train level system recovery values:
- Loss of Component Cooling Water
- Loss of All Service Water
- Loss of RCP Seal Cooling
- Interfacing Systems LOCA (ISL) re-evaluation using NUREG/CR-5928 and NUREG/CR-5744
- ATWS Event Tree revised to reflect WCAP-11992 ATWS evaluation structure

Reactor Protection Fault Trees

Added:

- Logic for failure of automatic actuation of Auxiliary Feedwater Pumps on Steam Generator Level
- Reactor trip failure due to mechanical control rod binding

Electrical Power System Fault Trees

- New Non-Safety AC and DC Power Fault Trees
- Consolidates failure logic located in several higher level system fault trees
- Swing Battery Chargers included in Loss of 125 VDC Bus Initiating Event fault trees
- Improved Dependency/Logic Loop break modeling

Essential Service Water / Normal Service Water System Fault Trees

Added:
- ESW/SW System failure caused by Frazil icing conditions/warming line failures
- ESW T&M Unavailability event when Service Water back-up is not feasible (e.g., ESW drained)

AFW and CCW System Fault Trees

Auxiliary Feedwater System
- Added undetected internal valve failure for CST AFW pumps suction header manual isolation valve APV0015

Component Cooling Water System
- Added T&M Unavailability event for entire CCW Train OOS (previously T&M events modeled at CCW pump level only)

Emergency Core Cooling/ RCP Seal Cooling System Fault Trees

- Replaced PDP With NCP
- Changed valves BGHV8357A/B to MOVs
- Added undetected internal valve failure for RWST ECCS pumps suction header manual isolation valve BNV0011
- Revise Accumulator Fault Tree in accordance with WCAP-15049 (Increased Completion Time from 1 hr to 24 hrs)
- Added Common Cause failure event for CCPs & SI Pumps due to gas entrainment/binding

New Fault Trees

Previously modeled as a single system level failure event (black box)
- Circulating Water System
- Condenser Vacuum System
- Fire Protection System
- Closed Cooling Water System

Data Analysis Changes

- Several generic data values
- Plant specific data updated through 1994
- Major active risk significant component groups
- Incorporated Maintenance Rule component failure history subsequent to 1994
- Parameter data file developed for rapid update of event values in basic event data (BED) file and fault trees
- Incorporation of new NRC Common Cause factors as appropriate
- Generic CCF retained when NRC CCF database applicability entries were sparse

Safety Monitor Tie-in

- Top logic fault tree developed to import model into the Safety Monitor. Top logic fault tree translates the Event Tree core damage sequences into a fault tree logic structure

4.1.1.1.4 PSA Model Maintenance

The WCGS PSA is based on a detailed model of the plant that was developed from the WCGS IPE. Improvements to the WCGS PSA model is an ongoing process. This is noted by the activities in Subsection 4.1.1.1.2. Planned updates to the PSA model are scheduled on a periodic basis by the PSA group. Planned updates include an information-gathering phase that is intended to capture plant changes that had not been previously identified by the PSA team. The PSA model has undergone an internal self-assessment and a Westinghouse Owner's Group Peer Review.

The Wolf Creek Nuclear Operating Corporation (WCNOC) engineering design process contains procedural screening questions to identify changes with potential impact to the PSA model. Example changes with identified impacts include changing an air-operated valve to a motor-operated valve and change-out of a reciprocating charging pump to a centrifugal pump with less cooling dependencies. With a mature plant and revised PSA model, plant changes that impact the model in a negative manner are becoming quite infrequent. Validation of operator action times for Safety Analysis purposes are used by the PSA group to confirm modeling of the human reliability analysis terms. PSA group judgment, of SSC performance issues identified under the Maintenance Rule, has altered the failure probabilities of an SSC until its performance was returned (or confirmed) to a satisfactory level.

4.1.1.1.5 Extension of 1998 WCGS PSA Model For DG Completion Time Extension

The PSA model to support the proposed extension of the DG Completion Time is a partial update that addresses the inclusion of Sharpe Station fault trees, DG T&M values, reactor coolant pump seal LOCA values, and Loss of Offsite Power initiating event frequencies for normal and protected conditions.

In 2002, an additional, nearby offsite power source (Sharpe Station) became available to Wolf Creek. The AC power source may be used during station blackout conditions. The 1998 PRA model was modified to make use of this new capability. Further discussion is included under RAI 5 in Attachment II.

The 1998 PRA model was modified to make use of the Sharpe Station capability. The WCGS model is constructed such that all cutsets that result in station blackout conditions are flagged. This flagging becomes a simple and effective way to consider the impact of having the Sharpe Station available to provide power to the plant through the switchyard.

As a flag event (i.e., value set to unity), the "SBO" term is present in any cutset combination that constitutes a station blackout. To utilize it to modify the probability of the plant to mitigate station blackout conditions with the added capability of the Sharpe Station, the value of SBO is changed to represent the top event failure probability of supplying power to the safety buses from the Sharpe Station. One limitation to applying this modified station blackout multiplier to all cutsets that result in a SBO event is that it non-conservatively reduces the value of cutsets that are essentially non-recoverable SBO scenarios. Such cutsets include failure of transformer XNB01 and coincident failures leading to both trains of essential service water (ESW) being functionally unavailable. These cutsets are considered non-recoverable since availability of the Sharpe Station to the switchyard does not mitigate progression to core damage. To account for this, a non-recoverable SBO fault tree was created to define these cutsets that effectively render the Sharpe Station ineffective.

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

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

4.1.1.1.6 Tabular Results as Presented in WCAP-15622

As noted previously, risk-informed support for the proposed extension of the Completion Time for an inoperable DG is based on PRA calculations performed to quantify the change in average CDF and average LERF. To determine the effect of the proposed change with respect to plant risk, the guidance provided in WCAP-15622 was used.

WCAP Table 8-1
Summary of Impact of DG Completion Time Change on Plant Risk
Completion Time Increase from 72 Hours to 7 Days

Parameter	
CDF (72 hr Completion Time) (per yr)	3.485E-05
CDF (7 day Completion Time) (per yr)	3.531E-05
CDF Increase (per yr)	4.56E-07
CCDF (DG in test or scheduled maintenance) (per yr)	5.17E-05
ICCDP (DG in test or scheduled maintenance)	4.56E-07

WCAP 15622 Table 8-2 Summary of Important PRA Assumptions and Modeling Features Relevant to the DG and DG CCF Completion Time Extensions		
Parameter	**DGs**	**Sharpe Station Diesels**
DG fail to start (per demand)	5.43E-03	3.0E-02
DG fail to run (per hour)	2.86E-02	4.8E-02
DG mission time (hours)	7	24
DG common cause failure model	Beta factor	MGL
DG fail to start common cause failure probability (per demand) Note 1	8.15E-05	2 of 5 9.17E-05 3 of 5 4.17E-05 4 of 5 5.24E-05 5 of 5 2.68E-04
DG fail to run common cause failure probability Note 1	6.28E-04	2 of 5 1.77E-04 3 of 5 1.11E-04 4 of 5 9.63E-05 5 of 5 5.34E-04
DG maintenance unavailability	5.16E-03	5.80E-03
Loss of offsite power initiating event frequency (per year) Note 2	Normal 2.848E-02 Protected 1.557E-02	

Note 1: Different values based on number of DGs involved. (NUREG/CR-5497)
Note 2: A Normal and Protected Loss of Offsite Power Initiating Event Frequency refers to the additional controls placed on switchyard work and other concurrent major maintenance.

WCAP 15622 Table 8-3 Summary of Plant Features Important to Loss of Offsite Power Events		
Plant	**DG Configuration**	**Alternate AC Source**
WCGS (1 Unit)	Two redundant Class 1E safety trains Each powered by 1 DG	Ten, two-megawatt Caterpillar 3516B engine-generator sets (Gensets) sited at a single location near an existing 69 kV substation near Sharpe, Kansas, approximately two miles north of WCGS (See Attachment II, RAI 5)

WCAP Table 8-4 Summary of Core Uncovery Probabilities During Station Blackout Events (Modified for Additional Work Restrictions)			
	Time	Normal	Protected
With RCS Cooldown	8 [1]	1.771E-02	1.886E-02
	12	1.236E-01	1.236E-01
Without RCS Cooldown	2	5.0E-03	5.0E-03
	8 [1]	2.203E-02	2.545E-02
	10	2.2E-01	2.2E-01

Note 1: While WCGS calculates an 8-hour term for both with and without RCS cooldown, only the value corresponding to "Without RCS Cooldown" is used. Therefore, values where "With RCS Cooldown" would be appropriate are considered conservative.

WCAP Table 8-6 Summary of Impact of AC Vital Bus Completion Time Change on Plant Risk Completion Time Increase from 2 Hours to 24 Hours[1]	
Parameter	
CDF (2 hour Completion Time) (per yr)	3.485E-05
CDF (24 hour Completion Time) (per yr)	No change in practice for increase in OOS due to TM.
CDF Increase (per yr)(assumes 24 hour outage time)	2.867E-07
CCDF (vital bus in repair) (per yr)	1.491E-04
ICCDP (vital bus in repair)	3.128E-07
Common cause model	MGL [2]
Common cause failure factor for failure of multiple buses [3]	2.14E-02

Notes:
1. These values corresponds to the highest importance vital bus.
2. MGL – Multiple Greek Letter
3. Common Cause terms are at the component level, not the bus level. Common Cause Factor listed for inverters.

WCAP 15622 Table 8-7 Summary of Plant Features Important to Vital AC Bus Completion Time Extension		
Plant	**120 Volt AC Vital Bus Configuration**	**Loss of Vital AC Power as an Initiating Event**
WCGS	Two safety trains with two vital buses per train Each vital bus normally powered from an inverter Alternate power from 120-volt ac inverter backup bus associated with the same load group through the manual transfer switch (USAR Figure 8.3-6)	Loss of a single vital AC bus should not lead to a reactor trip. Loss of two vital buses leads to a reactor trip.

4.1.1.1.7 Conclusions of Risk Analysis

Notwithstanding the noted changes, the plant-specific analysis that was performed for WCGS remains consistent with the approach described in the WCAP, and the conclusion supported by WCAP-15622 remains valid for supporting an extended DG Completion Time of 7 days when used for the purpose of performing planned, on-line DG maintenance at WCGS. The above-noted results obtained for WCGS demonstrate that the risk of performing DG on-line maintenance at power under an extended Completion Time of 7 days is acceptably small.

The overall results indicate that the loss of a vital AC bus is not a large contributor to plant risk. As indicated by these results, increasing the Completion Time for an inoperable vital bus to 24 hours, from 2 hours, has a relatively small impact on CDF and LERF. In addition, the ICCDP and ICLERP values are reasonable for a 24 hour period.

Since the analysis was based on the assumption of one such Completion Time for each DG per cycle, the extended Completion Time is to be specified as such in the WCGS TSs (i.e., "once per cycle for each DG"), as described in Subsection 2.1 and as reflected in the marked-up and revised TSs provided in Attachments III and IV, respectively. It should be noted that, as suggested previously, the analysis performed for supporting on-line DG maintenance (under the extended Completion Time) does not take into account the risk averted by moving such activities from shutdown modes to plant operation.

Although the results obtained from the evaluation demonstrate that the risk of performing DG on-line maintenance under the extended Completion Time is acceptably small, the analysis is conservative with respect to an assessment of overall risk since reduced shutdown risk would contribute to a reduction in the overall risk associated with the proposed change. Section 8.2.6 of the WCAP addresses this point, and provides further discussion about how moving DG maintenance activities out of shutdown conditions constitutes a reduction in shutdown risk. A quantitative assessment of this reduced risk is provided in the WCAP using the shutdown PRA model for Comanche Peak. As noted in the WCAP, the results of that analysis are considered to be generally applicable to all of the participating plants, and therefore this conclusion is supported for WCGS as well.

4.1.1.2 Tier 2: Avoidance of Risk-Significant Plant Conditions

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

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

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

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

4.1.1.3 Tier 3: Risk-Informed Plant Configuration Control and Management

The objective of the third tier is to ensure that the risk impact of out-of-service equipment is evaluated prior to performing any maintenance activity. As stated in Section 2.3 of Regulatory Guide 1.177, "a viable program would be one that is able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation." The third-tier requirement is an extension of the second-tier requirement, but addresses the limitation of not being able to identify all possible risk-significant plant configurations in the second-tier evaluation.

The risk impact associated with performance of maintenance and testing activities is evaluated in accordance with the WCGS Operational Risk Assessment Program (administrative procedure AP 22C-003). An Operational Risk Assessment is performed for activities within a weekly schedule. Compensatory measures are addressed for activities deemed to be risk significant. The weekly scheduled activities and associated Operational Risk Assessment are reviewed by the WCGS PSA Group and approved by the Plant Manager or designee. The Operational Risk Assessment Program also addresses the impact on the Operational Risk Assessment due to added or emergent activities and activities which have slipped from the scheduled completion time.

4.2 Changes to Second Completion Times

As discussed in Subsection 3.2, the second Completion Time is included in the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions of inoperability during any single continuous failure to meet the LCO. The intent of the second Completion Time is to preclude entry into and out of the ACTIONS for an indefinite period of time by providing a limit on the amount of time that the LCO could not be met for various combinations of Conditions.

The addition of the Note to Required Action A.3 and Required Action B.4 provides an additional second Completion Time of 10 days from discovery of failure to meet the LCO. The second Completion Times in TS 3.8.9 are revised from "16 hours from discovery of failure to meet LCO" to "34 hours from discovery of failure to meet LCO." The second Completion Times are an administrative limit intended to prevent the plant from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO (*i.e.*, "*flip flopping*"). The second Completion Times are generally the sum of the component Completion Times that could be successively entered. This administrative limit is calculated without regard to the method used to determine the component Completion Times. Therefore, an extension of one of the component Completion Times will result in a corresponding extension of the "modified time zero" Completion Time. The changes to the second Completion Times are consistent with that approved in Reference 3.

5.0 REGULATORY ANALYSIS

5.1 NO SIGNIFICANT HAZARDS CONSIDERATION

WCNOC has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

(1) Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes to the Completion Times do not change the response of the plant to any accidents and have an insignificant impact on the reliability of the electrical power sources and distribution systems. The proposed changes to the second Completion Times are administrative in nature and only intended to prevent the plant from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO. The electrical power sources and distribution subsystems will remain highly reliable and the proposed changes will not result in a significant increase in the risk of plant operation. This is demonstrated by showing that the impact on plant safety as measured by core damage frequency (CDF) and large early release frequency (LERF) is acceptable. In addition, for the Completion Time change, the incremental conditional core damage probabilities (ICCDP) and incremental conditional large early release probabilities (ICLERP) are also acceptable. These changes are consistent with the acceptance criteria in Regulatory Guides 1.174 and 1.177. Therefore, since the electrical sources and distribution subsystems will continue to perform their functions with high reliability as originally assumed, and the increase in risk as measured by CDF, LERF, ICCDP, ICLERP is acceptable, there will not be a significant increase in the consequences of any accidents.

The proposed changes do not adversely affect accident initiators or precursors nor alter the design assumptions, conditions, or configuration of the facility or the manner in which the plant is operated and maintained. The proposed changes do not alter or prevent the ability of structures, systems, and components (SSCs) from performing their intended function to mitigate the consequences of an initiating event within the assumed acceptance limits. The proposed changes do not affect the source term, containment isolation, or radiological release assumptions used in evaluating the radiological consequences of an accident previously evaluated. Further, the proposed changes do not increase the types or amounts of radioactive effluent that may be released offsite, nor significantly increase individual or cumulative occupational/public radiation exposures. The proposed changes are consistent with the safety analysis assumptions and resultant consequences.

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

(2) Does the proposed change create the possibility of a new or different accident from any accident previously evaluated?

Response: No.

The proposed changes do not result in a change in the manner in which the electrical distribution subsystems provide plant protection. The use of the Sharpe Station will provide an alternate AC power source in the event of emergent inoperability of a WCGS DG or a complete loss of all WCGS emergency AC power. The changes do not alter assumptions made in the safety analysis. The changes to Completion Times do not change any existing accident scenarios, nor create any new or different accident scenarios. The proposed changes are consistent with the safety analysis assumptions and current plant operating practice.

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

(3) Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed changes do not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined. The safety analysis acceptance criteria are not impacted by these changes. The proposed changes will not result in plant operation in a configuration outside the design basis. The calculated impact on risk is insignificant and is consistent with the acceptance criteria contained in Regulatory Guides 1.174 and 1.177.

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

Based on the above evaluation, WCNOC concludes that the proposed amendment involves no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

5.1 APPLICABLE REGULATORY REQUIREMENTS

This amendment application would revise Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Times for the Required Actions associated with an inoperable DG. This amendment application requests revision of TS 3.8.9, "Distribution Systems – Operating," to extend the Completion Time for one AC vital bus subsystem inoperable. The proposed Technical Specification changes have been developed in accordance with the NRC's Safety Goal Policy Statement, Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p. 42622, August 18, 1995, and guidance contained in Regulatory Guide 1.174 and Regulatory Guide 1.177. Evaluation of the proposed changes has determined that the associated risk is acceptably small, as the acceptance criteria specified in the above Regulatory Guides are met. The proposed changes to the second Completion Times are administrative in nature and only intended to prevent the plant from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO.

Based on the considerations discussed above, (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.

6.0 ENVIRONMENTAL CONSIDERATION

WCNOC has evaluated the proposed amendment for environmental considerations. The review has determined that 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, and would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendments.

7.0 REFERENCES

1. Westinghouse Owners Group Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times,: Non-Proprietary Class 3.

2. Industry/Technical Specifications Task Force (TSTF) Standard Technical Specification (STS) Change Traveler TSTF-417, "AC Electrical Power System Completion Times (WCAP-15622)," Revision 0.

3. NRC Letter, D. Jaffe to W. Eaton, "Grand Gulf Nuclear Station, Unit 1, Issuance of Amendment RE: Extended Allowed Outage Time for Diesel Generators (TAC NO. MB3973)," July 16, 2002.

4. Regulatory Guide 1.155, "Station Blackout," August 1998.

5. WOG Letter, R. Bryan to Document Control Desk, "Transmittal of WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times'," OG-01-039, June 15, 2001.

6. NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, "Risk- Informed Evaluation of Extensions to AC Electrical Power System Completion Times, Request for Additional Information (TAC No. 2257)."

7. NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, "Risk- Informed Evaluation of Extensions to AC Electrical Power System Completion Times," January 15, 2002.

8. WOG Letter, R. Bryan to Document Control Desk, "Transmittal of RAI Responses for WCAP-15622, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times," OG-02-052, November 27, 2002.

9. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.

10. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," August 1998.

11. WCNOC Letter, B. McKinney to Document Control Desk, "Revision to Technical Specifications 3.8.1, 'AC Sources – Operating,' and 3.8.4, 'DC Sources – Operating,'" WO 03-0009, April 30, 2003.

8.0 PRECEDENTS

The NRC staff has approved similar license amendments for other plants including Nos. 114, 114, 108, and 108 for Byron Station, Units 1 and 2, and Braidwood Stations Units 1 and 2, respectively, on September 1, 2000; No. 141 for Clinton Power Station, Unit 1, on November 8, 2001; and Nos. 150 and 136 for LaSalle County Station, Units 1 and 2, respectively, on January 30, 2002. Additionally, the changes to the second Completion Times are consistent with Amendment No. 151 for Grand Gulf Nuclear Station, Unit 1.

Plant Specific Information in Support of Responses to NRC Request for Additional Information Regarding WCAP-15622

Following submittal of the subject Topical Report (WCAP-15622, Rev. 0) by the Westinghouse Owners Group (WOG) in June 2001, the NRC staff issued two requests for additional information (RAIs) in January 2002. Response to both of the NRC's RAI letters were subsequently provided by the WOG in letter OG-02-052, dated November 27, 2002, specifically in Attachments 1 and 2 of that letter respectively. In the WOG's response to the NRC requests, each individual request or question contained in the NRC's letters was assigned an RAI number. In addition, the RAIs addressed in the WOG letter of Attachment 1 were categorized into groups based on the subject and type of response required, including consideration of which responses would require plant-specific responses or additional plant-specific information, from licensee's in their individual license amendment requests.

The generic WOG responses that were provided for these RAIs in the Attachments of the WOG letter are repeated here for context. WCNOC is providing plant-specific responses or additional plant-specific information as identified in the WOG responses to the RAIs.

RAI 2. The staff noted that WCAP-15622 review methodology does not include probabilistic risk assessment (PRA) quality criteria for the evaluation of AC electrical power source completion times. Discuss PRA quality measures, including peer reviews, and how WCAP-15622 addressed individual plant PRA quality for the proposed plants and PRA quality guidance for subsequent plant specific submittals, including those plants not included in WCAP-15622.

WOG Response: The detailed response to this RAI will be provided in each licensee's License Amendment Request (LAR) following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the changes proposed in this WCAP, those included in the WCAP and those referencing the WCAP in future LARs, will provide a discussion of the following:

- Utility's PRA quality program and how it ensures that the model represents the as-built, as-operated plant.
- IPE findings, related to the AC systems, and how they were addressed.
- Peer review findings, related to the AC systems, and how they were addressed. If the peer review findings, related to the AC power system, have not yet been addressed, the possible impact of these findings on the results presented in WCAP-15622 will be discussed.
- Findings of any other PRA reviews, related to the AC systems, and how they were addressed.

WCNOC Response:

- Utility's PRA quality program and how it ensures that the model represents the as-built, as-operated plant.

Subsection 4.1.1.1.3 of Attachment I of this letter discusses the WCGS Probabilistic Safety Assessment (PSA) maintenance program. Those activities cause the PSA model to reflect the plant condition.

- IPE findings, related to the AC systems, and how they were addressed.

No significant issues were identified in the Individual Plant Examination (IPE) for the AC power systems that require additional consideration in this evaluation of Completion Time extension. NRC RAI Front End Question 7 f) sought to identify credit for changes as a result of the Station Blackout Rule. At that time, high temperature qualified reactor coolant pump seals were not installed. The PSA model for this completion time extension evaluation does credit the new style seals. The final Reactor Coolant Pump (RCP) seal upgrade is to be implemented during the upcoming Fall 2003 Refueling Outage.

<u>1998 Self-Assessment to Identify PSA Weaknesses and Guide Update Priorities</u>

Performance Improvement Report 1998-1669 called for non-standard mission times to be validated and documented. The mission time for the diesel generators (DGs) was changed from 2.5 hours in the 1996 quantification to 7 hours. From Calculation AN 98-046:

> "A seven hour mission time is appropriate for core damage sequences with failure of one DG to run, failure of the other DG to start (e.g., DG-FS, DG-TM) and failure of offsite power recovery within 8 hours (the turbine driven AFW pump operates successfully). Sequences with failure of offsite power recovery within 8 hours and failure of both DG to run were estimated to require a DG mission time of 9 hours with no credit for recovery of a failed DG. However, it is judged that with reasonable consideration for recovery of a failed DG that a seven hour DG mission time is appropriate even for these limiting sequences. Additionally there are many sequences for which a seven hour mission time will be conservative (e.g., for sequences with successful recovery within 8 hours but core uncovery has occurred before the time of core uncovery an appropriate mission time would be less than 6.5 hours since about 90 minutes are required to uncover following a loss of seal cooling). Therefore a 7 hour mission time is judged to be a conservative average DG mission time for CDF sequences."

- Peer review findings, related to the AC systems, and how they were addressed. If the peer review findings, related to the AC power system, have not yet been addressed, the possible impact of these findings on the results presented in WCAP-15622 will be discussed.

The objective of the PSA Peer Review process is to provide a method for establishing the technical quality and adequacy of a PSA for a spectrum of potential risk-informed plant applications for which the PSA may be used.

The two Significance Level 'A' Facts and Observations (F&O) are described and addressed below. In addition, there was one additional F&O that was a potential impact to the extended 1998 PSA Model for this application.

F&O IE-3 questioned the method of Bayesian updates. The LOSP initiating event frequency was the only one impacted by the calculational technique. In this application, Bayesian updating of the LOSP initiating event frequency was not performed. Additional discussion is found with the response to RAI 8.

Significant WOG Peer Review Findings on the 1998 WCGS PSA Model:

The first 'A' significance Fact & Observation (F&O, identified as DA-2) basically states that no unique time frame is established for plant data collection for use in developing plant specific data variables. A review of WCGS PSA documents, including a draft data updating desktop guidance, did not reveal any specific instruction as to the periodicity for plant data collection. Additionally, review of a similar data update guidance document from another utility indicated no set period for data collection. Subsequent to these reviews, this issue was forwarded to Scientech, Inc., who currently is under contract to WCNOC to provide technical support and advice for updating the WCGS PSA model. Scientech's response follows:

Recommendation:

It is accepted practice to use different time intervals for different components or initiating events in a PSA. It is standard practice to combine generic data with plant specific data collected over a different time period.

Basis for Recommendation

Industry Documents
The ASME Standard suggests collecting plant specific data from "as broad a time period as possible, consistent with uniformity in design, operational practices, and experience". As long as the data remains applicable to the components, the additional information better defines the failure rate and its uncertainty.

Background
When obtaining generic data, one is limited by the data collection studies readily available for public use. Typically, such data collection studies do not contain all of the components necessary for a complete PSA for a given plant. Therefore, several different data collection studies, and possibly expert judgment, may be needed to obtain a complete set of generic data that is deemed applicable to the equipment being modeled at a specific plant (e.g., NUREG/CR-4639 and NUREG/CR-4550 for component failure rates, NUREG/CR-5497 and NUREG/CR-6268 for common cause failures, and NUREG/CR-5496 and

NUREG/CR-5032 for AC power recovery). As a direct result, there will necessarily be different exposure times, run times, etc.

Typically, a process is outlined for determining generic component failure rates where the generic data is selected from a specific reference document. If the generic data from this first source is determined to be not applicable to the plant in question, then a second (or third, expert judgment, etc.) is considered until a suitable generic value is determined. This process is repeated for each component in the plant model.

Generic Data and the Update Process

It is standard practice to combine generic data collected over one time frame with plant specific data collected over a different time period. For example, the data in a study that has just been published will be at least 1 year old. This is because the end date of the study period must be chosen prior to the initiation of the collection task. By the time the data has been collected, analyzed, and processed and the draft report written, reviewed, finalized, and published, the data is at least 1 year old. When one considers that large-scale data studies are performed only every 3 or 4 years, the most commonly used references are several years old. By contrast, plant specific data can be as little as a few months old.

When generic data is combined with plant specific data, typically a single-stage Bayesian Update process is used. This process incorporates the "strength" of the plant specific data in terms of the number of demands or operational hrs. and the number of failure events. If the rather more complex two-stage Bayesian Update process is used, the "strength" of both the generic data and the plant specific data is incorporated in the update process.

Plant Specific Data

This discussion applies to both component hardware failure data and initiating event data. However, there is no requirement that the same data collection timeframe be used for both sets of data. Typically, the more plant years included in the initiating event database the better, as these events have a low frequencies and the additional time provides a more accurate assessment of the initiating event frequencies.

While it may be desirable to have the same time frame for all components in the plant specific data, in practice this may not be possible. This could be due to things such as plant record keeping for non-safety grade components, etc. If a component has been replaced with a non-identical new component, then there will be a shorter time period over which to collect data for the new component (as the data from the old component is no longer applicable). Any such occurrences should be well documented. Additionally, if a particular component is found to be significant to the CDF, a more detailed analysis of that component's performance may be performed considering a longer or shorter time period (with justification). All of these are valid and accepted reasons to have different periods of collection time in the plant specific component database.

As with the selection of generic data, the collection of plant specific data should follow a set procedure. A time frame over which plant data is collected should be determined based on the availability of records, etc. A systematic approach should be outlined that explains how to handle cases where it is not possible to obtain data for all of the specified time period, or where (for various reasons) it is not desirable to use the selected period (missing or unavailable records, component replaced with a non-identical new component, inconclusive operational history, etc.).

A typical data update process would be:

- Determine time frame for data collection (e.g., 01-01-1985 through 31-12-2001)
- Collect data, document problem areas (missing data records)
- Determine component demands, operational hrs., and exposure times
- Process data (evaluate plant specific data, update generic data), document results
- Quantify PSA, identify important components
- Review data for important components

Based on the results of the importance review, additional review and potential revision of specific data values may be performed. This could include:

- Review of the selected generic data for applicability
- Review of the selected generic data to verify that it is reasonably current
- Review of the identified failure events to verify that they are all independent failures (e.g., look for potential cases where a component fails repeatedly till properly repaired - such events should only be counted as one failure if they occur sequentially).
- Review the component demands, operational hrs., and exposure times

Note that plant specific data is no longer plant specific if it is used as the basis for extrapolation to cover a longer period of time. This would skew the results of a Bayesian Update process in terms of both the mean value and error factor.

At this point, the options available to reduce a component failure are:

- Obtain more applicable generic data (this may increase or decrease)
- Collect additional plant data (additional operational years)
- Review component history (has it been significantly rebuilt or replaced, and if so, when?)
- Compare the failure history with the component history (for each specific component in the component group), looking for patterns between rebuild/replacement and failures.
- Review operating procedures to determine if a change in component usage has occurred.
- Perform a trend analysis.

Based on the results of the above process, the use of a different data time frame may be justified. Just because throwing out or including a few years reduces the failure rate does not justify doing so, there must be a documented rational. The data value can then be recalculated and the PSA requantified. Sensitivity analysis should be performed to provide insight into the significance of a data change.

Such a process should be documented in a procedure or guideline and consistently implemented on all plant specific data. For each piece of data that has been modified the supporting rational must be documented in the database discussion. This applies to cases where data is not available for the complete data period or cases where additional analysis is performed.

Per the previous discussion, provided by Scientech, the issue of F&O DA-2 is, at most, a concern of no significance. WCNOC's ongoing update of the PSA model is utilizing plant specific component failure data and system/train unavailabilities as documented in the WCGS Maintenance Rule database.

The second 'A' significance Fact & Observation (F&O, identified as QU-2) discussed the Loss of All Service Water (SWS) Initiating Event, and other transient type initiators for which the Essential Service Water (ESW) pumps do not receive an automatic start signal. This F&O is not applicable to this application. The F&O was written because the reviewers observed specific Loss of SW cutsets where the recovery terms were not intuitive and not adequately explained.

RAI 5. Information Notice 97-02, "Availability of Alternate AC Power Source Designed for Station Blackout Event" addressed potential unavailability of alternate AC power sources and noted that the capability to start on demand depends on the unavailability of support systems that may require AC or DC power. Determine the applicability of information notice 97-02 to WCAP-15622 review methodology and implementation guidelines.

(Note that Information Notice 97-02 is "Cracks Found in Jet Pump Riser Assembly Elbows at BWRs". Information Notice 97-21 is "Availability of Alternate AC Power Source Designed for Station Blackout Event". Information Notice 97-21 is the document applicable to this WCAP.)

WOG Response: The detailed response to this RAI will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the DG CT extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future LARs, will provide a discussion on the applicability of this Information Notice.

WCNOC Response: Kansas Electric Power Cooperative, Inc. (KEPCo), Kansas Gas and Electric Company (a wholly owned subsidiary of Western Resources, Inc.) doing business as Westar Energy, and Kansas City Power & Light Company (a wholly owned subsidiary of Great Plains Energy, Inc.) are WCNOC's owner companies.

In 2002, KEPCo constructed an electric generating station that consists of ten, two-megawatt Caterpillar 3516B engine-generator sets (Gensets). They are arranged in two banks of five with separate transformers. The Gensets are sited at a single location near an existing 69 kV substation near Sharpe, Kansas, approximately two miles north of WCGS. Siting it near WCGS provides emergency back-up power for WCGS, specifically, to improve availability and reliability of sufficient AC power for planned or postulated WCGS plant conditions including planned onsite DG maintenance, emergent failure of one onsite DG, complete loss of all onsite emergency AC power, and grid perturbations or loss of a normal offsite power source to WCGS. An Operating Agreement is in effect between KEPCo and WCNOC for the use and maintenance of the Sharpe Station.

Sharpe Station generation has been modified for blackstart. Power from the Sharpe Station enters the WCGS switchyard via the existing Phillips 69-kV line (see figure on Page 5 of 27 in Attachment I and also see USAR Figure 8.2-4-00, G-6). The Phillips line is lightly loaded and radial fed from the WCGS 69-kV substation. Four-out-of-ten gensets are required to support one safety buss with LOCA Loads. The logic for breaker 69-4 will be modified to close with the line side energized and the 69 kV bus de-energized.

With the installation of ten Gensets north of the WCGS site as the Sharpe Station, evaluations were initiated to determine potential benefit to WCGS as an alternate AC (AAC) power source. A review of Regulatory Guide 1.155, "Station Blackout," regarding characteristics of an AAC power source for station blackout (SBO) scenario, revealed the following design criteria:

1. The AAC power source should not normally be directly connected to the preferred or the blacked-out unit's onsite emergency ac power system.

2. There should be a minimum potential for common cause failure with the preferred or the blacked-out unit's onsite emergency ac power sources. No single-point vulnerability should exist whereby a weather-related event or single active failure could disable any portion of the blacked-out unit's onsite emergency ac power sources or the preferred power sources and simultaneously fail the AAC power source.

3. The AAC power source should be available in a timely manner after the onset of station blackout and have provisions to be manually connected to one or all of the redundant safety buses as required. The time required for making this equipment available should not be more than 1 hour as demonstrated by test. If the AAC power source can be demonstrated by test to be available to power the shutdown buses within 10 minutes of the onset of station blackout, no coping analysis is required.

4. The AAC power source should have sufficient capacity to operate the systems necessary for coping with a station blackout for the time required to bring and maintain the plant in safe shutdown.

5. The AAC power system should be inspected, maintained, and tested periodically to demonstrate operability and reliability. The reliability of the AAC power system should met or exceed 95 percent as determined in accordance with NSAC-108 or equivalent methodology.

The Sharpe Station meets items 1 and 4 above.

Item 2 is met by the overall design of the WCGS switchyard. However, severe weather that impacts the switchyard can be postulated, thereby affecting the normal offsite power sources and the Sharpe Station line. Additional discussion is provided in RAI-7.

For Item 3, AC power from the Sharpe Station will be available without delay. The extended DG maintenance period is a scheduled and planned evolution, and appropriate contacts will be prepared to take action in a very timely manner. Possible changes to plant operating procedures will be reviewed for further enhancements in power restoration. It is not the intent of WCNOC, at this time, to make the Sharpe Station available within a 10-minute period for the purpose of avoiding a station blackout coping analysis.

Item 5 addresses acceptable performance. KEPCo added the Sharpe Station for commercial considerations. An Operating Agreement between WCNOC and KEPCo calls for maintenance consistent with the manufacturers' recommendations and prudent utility practice. Maintenance runs are performed on each Genset on a monthly basis. WCNOC has priority dispatch status in the event of emergent inoperability of a WCGS DG or a complete loss of all WCGS emergency AC power. In addition WCNOC will be notified without delay when the Sharpe Station unit capability is determined to be less than 50% of design capacity. Performance information, such as status of each Genset (daily), component failures of the Gensets and supporting electrical switchgear will be available to WCGS.

In consideration of the above, the Sharpe Station is credited as an additional AC power source in the 1998 PSA model modified for the DG Completion Time extension. Sharpe Station is not credited as an Alternate AC (AAC) power source as defined in Regulatory Guide 1.155, "Station Blackout."

RAI 6. Provide the values for emergency diesel generator (EDG) reliability and unavailability used in the PRA calculations including SBO (include alternate AC source if applicable). Discuss these values in relationship to the maintenance rule implementation goals and comparison to actual EDG performance and SBO commitments. Discuss incorporation into WCAP-15622 implementation guidelines.

WOG Response: The additional information requested regarding the Maintenance Rule implementation goals, and comparison of actual EDG performance and SBO commitments (including the alternate AC source if applicable) will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the DG CT extension proposed in this WCAP, those currently included in the WCAP and those referencing the WCAP in future requests, will provide the following:

- EDG fail to start and fail to run values
- EDG maintenance unavailability with 3 day CT and with 7 day CT
- Alternate AC source failure probability values (if applicable)
- Alternate AC source maintenance unavailability (if applicable)
- Short discussion with regard to these values relative to Maintenance Rule goals, actual EDG performance, and SBO commitments.

WCNOC Response:

WCAP 15622 Table 8-2 Summary of Important PSA Assumptions and Modeling Features Relevant to the DG and DG CCF Completion Time Extensions

Parameter	DGs	Sharpe Station Diesels
DG fail to start (per demand)	5.43E-03	3.0E-02
DG fail to run (per hour)	2.86E-02	4.8E-02
DG mission time (hours)	7	24
DG common cause failure model	Beta factor	MGL
DG fail to start common cause failure probability (per demand) Note 1	8.15E-05	2 of 5 9.17E-05 3 of 5 4.17E-05 4 of 5 5.24E-05 5 of 5 2.68E-04
DG fail to run common cause failure probability Note 1	6.28E-04	2 of 5 1.77E-04 3 of 5 1.11E-04 4 of 5 9.63E-05 5 of 5 5.34E-04
DG maintenance unavailability	5.16E-03	5.80E-03
Loss of Offsite Power Initiating Event Frequency (per year) Note 2	Normal 2.848E-02 Protected 1.557E-02	

Note 1: Different values based on number of DGs involved. (NUREG/CR-5497)
Note 2: A Normal and Protected Loss of Offsite Power Initiating Event Frequency refers to the additional controls placed on switchyard work and other concurrent major maintenance.

For the purposes of the Maintenance Rule, three criteria were established to monitor the performance of the DGs. The first criterion is DG unavailability. For WCGS, the DG unavailability goal is ≤ 265 hours per train per 18 months. Current data indicates that DG unavailability is approximately one half of the established goal.

The second criterion 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 goal.

The third criterion is associated with the DG Reliability Program for 1) no more than 3 start or load/run failures in the last 20 demands, 2) no more than 5 start or load/run failures in the last 50 valid demands, and 3) no more than 8 start or load/run failures in the last 100 valid demands. Since 1990, a total of 2 start failures and 3 load/run failures have occurred. The last failure was a load/run failure on February 11, 2000. The reliability of the DGs is 99.109%.

RAI 7. For plants that take credit for an alternate AC source, provide a discussion on the vulnerability of the alternate AC source to external events (including weather-related events) that could disable the alternate AC power source, the emergency AC power source, or the normal offsite power sources. Include common cause failure mechanisms between the normal electrical distribution system and the alternate AC source. Discuss the impact of external events on the availability of alternate sources of AC power (SBO diesels for example) with respect to WCAP-15622 and the included implementation guidelines. Provide a discussion as to the assumptions (qualification) and risk impact of the alternate AC source.

WOG Response: The detailed response to this RAI will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the DG CT extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future requests, will provide a discussion on the vulnerability of their alternate AC power source to external events as requested above. Note that Catawba and McGuire are the only plants currently included in the WCAP that credit an alternate AC power source.

WCNOC Response: The Sharpe Station discussed in RAI 5 is a new source of AC power available to WCGS. It is connected to the WCGS switchyard through the existing Phillips line. Four (4) gensets are required to support one safety bus with LOCA loads. The incoming power line-up utilizes different transformers from the normal lineup (#4 and #5 versus #7 transformer). On a total loss of offsite power, 345 kV (and 69 kV) lost, both NB01 and NB02 can be tied together using tie breaker from ESF transformer XNB01 to safety bus NB02, breaker NB0212.

There are no commonalties between the WCGS DGs and Sharpe Station. Severe weather that impacts the WCGS switchyard can be postulated, thereby affecting the normal offsite power sources and the Phillips (Sharpe Station) line. To minimize this possibility, WCNOC intends to perform the extended DG maintenance period during historical time frames of low severe weather frequency. Favorable weather periods also tend to avoid time periods of high grid demand. The response to RAI 8 discusses changes to the Loss of Offsite Power Initiating Event Frequency.

Prior to entering the planned DG maintenance, WCNOC will check weather forecasts for severe weather predictions. If the forecast is not favorable, the maintenance start will be delayed or rescheduled if necessary. Other external events, such as flooding and transportation, do not involve significant hazards to the Sharpe Station due to its location away from major highways and water sources.

The representation of the Sharpe Station in the PSA model includes common cause failure terms in its fault trees. Due to the Sharpe station design, common cause is not an important contributor of failure to deliver power to the emergency plant equipment.

RAI 8. The results for Delta CDF and incremental conditional core damage probability (ICCDP) shown in Table 8-1, Table 8-5 and Table 8-6 are not consistent with the Regulatory Guide (RG) 1.174 , "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.174 (correction, 1.177), "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications" guidance. Numerous results show what appears to be substantial differences from the guidelines. Discuss these differences and include any compensatory measures (or guidance) before and during diesel generator maintenance or AC bus restoration including 10 CFR 50.65 maintenance rule provisions or surveillances to be performed to ensure operability of systems associated with the remaining equipment (EDG, AC Bus). Include how these measures will be documented. Discuss any suggested revisions to the requested LCOs that will bring impacts into alignment with RG 1.174 and RG 1.177 guidelines or propose an alternate basis for acceptability.

WOG Response: Only portions of the WOG response in letter OG-02-052 are provided. Not all the results presented in the WCAP differ substantially form the acceptance guidelines provided in RG 1.174 and RG 1.177.
The utilities with plant specific information included in the WCAP have reviewed their results and are reconsidering their Completion Time extension requests. Several changes to the analyses have been considered and implemented. These include:

- Revised analyses based on updated PRA models
- Revised analyses crediting reduced LOSP frequencies during maintenance activities
- (Note that this approach is only used for plants that need to 1) credit restrictions on plant activities concurrent with DG outages and/or 2) restrict DG outages to times of high grid reliability to meet the risk acceptance criteria in Regulatory Guides 1.174 and 1.177. This is discussed in more detail below.)
- Reduced Completion Time extension requests
- Shorter Completion Time extension requests for the higher importance buses

The analysis changes implemented by each licensee are plant specific and are discussed with the plant specific revised results on the following pages.

Reduced LOSP frequencies during maintenance activities

For scheduled DG maintenance activities and repairs that follow scheduled test activities it is possible to control other plant activities that are scheduled and also the time of the year when the activity is planned. Control of these elements can result in a reduced probability of a loss of offsite power event when scheduled DG maintenance activities are in progress. Restrictions can be placed on:

- Concurrent (with the DG outage) electrical switchyard activities

- Concurrent (with the DG outage) activities that can impact the reliability of the electrical switchyard
- Access to the electrical switchyard
- Time of the year when the activity is scheduled

An approach was developed for utilities to use to calculate a plant specific LOSP initiating event frequency for scheduled maintenance activities. This approach requires a review of the LOSP events that have occurred along with a plant specific assessment of the applicability of these events given the possible restrictions listed above. Based on this review and the restrictions utilities will put in place when in an extended DG outage for a scheduled activity, a number of LOSP events can be eliminated from the database. Based on the remaining events, a generic LOSP initiating event frequency can be calculated for scheduled maintenance activities. This generic value can then be Bayesian updated with plant specific experience. The steps in this process are:

1: Identify Plant Restrictions
2: Assess the Applicability of Plant-Centered Events
3: Assess the Applicability of Grid-Related Events
4: Assess Applicability of Weather-Related Events
5: Calculate Generic LOSP IE Frequency
6: Calculate Plant Specific LOSP IE Frequency
7: Bayesian Update of Generic LOSP IE Frequency with Plant Specific Information

Several of the participating utilities used this approach to justify the extended Completion Time for scheduled activities on the DGs. This approach may or may not result in a split Technical Specification Completion Time; the current Completion Time (72 hours) for repair activities and an extended Completion Time (7 days or greater) for scheduled maintenance activities (or repair activities that follow scheduled test activities). This approach may also result in restrictions or preconditions when performing scheduled activities on the DGs. These restrictions will be documented in plant procedures or through the plant specific configuration risk management program per (a)(4) of the Maintenance Rule.

WCNOC Response: This question refers to information provided in the original submittal of WCAP-15622. WCNOC intends to follow the Regulatory Guide 1.174 and Regulatory Guide 1.177 guidelines in developing and proposing these changes to Technical Specifications.

Changes to the WCGS 1998 PSA Model for this application make use of the above-described plant-specific LOSP initiating event frequency modification. An EPRI database of 72 LOSP events covering 1980 through 2002 was reviewed and categorized per 2, 3, and 4 above (EPRI-TR-106306, 1002987 & 1008052). They were further reviewed to determine the basic cause of the event. For plant-centered events, consideration is given to equipment failures, maintenance related, and operator errors. For grid related events, consideration is given to grid stability issues and external events (other than weather related) that could impact the grid. For weather related events, consideration is given to plant location and time of year for planned extended maintenance activities. Bayesian updating was not done and, therefore, these generic numbers are considered conservative.

To take credit for the reduction in severe threat, historical severe weather data was collected. Data was obtained from the National Oceanic and Atmospheric Administration's (NOAA) National Severe Storms Laboratory Severe Thunderstorm Climatology website (http://www.nssl.noaa.gov/hazard/) specific to wind, hail, and tornadic activity for the WCGS area -- averages from 1980 to 1999. This data was then used to determine a percent reduction in the probability of occurrence of severe weather during a specified time of year. This percentage would then be representative of the reduction of expected weather centered loss of offsite power events.

The resultant Normal and Protected LOSP Initiating Event Frequencies are shown in Subsection 4.1.1.1.6 and in the response to RAI 6.

RAI 9. RG 1.177 states that when multiple TS changes are being considered, the combined impact of the changes should be considered in addition to the individual impacts. Appendix C, Step 7, states that cumulative risk needs to be determined but the results are not discussed in WCAP-15622. Provide a discussion of the combined impact of the proposed changes with respect to WCAP-15622.

WOG Response: Only a portion of the WOG response in letter OG-02-052 is provided. The CT extensions are, for the most part, independent of each other. Therefore, to determine the cumulative impact it is only necessary to sum the individual contributions. This is shown on Table RAI 9-1 in terms of CDF and in Table RAI 9-2 in terms of LERF for the plants providing updated risk results. All increases in CDF and LERF are less than the 1E-06/yr CDF guideline and the 1E-07/yr LERF guideline in Regulatory Guide 1.174.

WCNOC Response: The Completion Time extensions requested in this LAR are, for the most part, independent of each other. Therefore, to determine the cumulative impact it is only necessary to sum the individual contributions. The values for WCGS are shown on Table RAI 9-1 in terms of CDF and in Table RAI 9-2 in terms of LERF. All increases in CDF and LERF are less than the 1E-06/yr CDF guideline and the 1E-07/yr LERF guideline in Regulatory Guide 1.174.

Table RAI 9-1
Combined Core Damage Frequency Impact of the Individual Technical Specification Completion Time Extensions

TS Completion Time Change	Core Damage Frequency Change
DG Completion Time Increase (LCO 3.8.1, Required Action B.4)	ΔCDF = 4.56E-07
Vital AC Bus Completion Time Increase (LCO 3.8.9, Required Action B.1)	ΔCDF = 2.867E-07
Total	ΔCDF_{Total} = 7.43E-07

Table RAI 9-2 Combined Large Early Release Frequency Impact of the Individual Technical Specification Completion Time Extensions	
TS Completion Time Change	Large Early Release Frequency Change
DG Completion Time Increase (LCO 3.8.1, Required Action B.4)	ΔLERF = 1.070E-08
Vital AC Bus Completion Time Increase (LCO 3.8.9, Required Action B.1)	ΔLERF = 4.92E-09
Total	$\Delta LERF_{Total}$ = 1.56E-08

RAI 10. For alternate AC sources credited in the analysis, confirm that the credited AC source meets the criteria set forth for SBO performance in industry and staff guidance (RG 1.155 and NUMARC 8700).

WOG Response: The detailed response to this RAI will be provided in each licensee's License Amendment Request following the NRC's approval of the changes proposed in WCAP-15622. Each licensee requesting the DG completion time extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future LARs, will provide the requested information.

WCNOC Response: The nearby Sharpe Station is credited in the WCGS 1998 PSA extended model used to support this license amendment request. The Sharpe Station is not an alternate AC source as defined by Regulatory Guide 1.155. Additional discussion of Sharpe Station is given in the response to RAI 5 and RAI 7.

RAI 11. The proposed completion times are requested in part to facilitate on-line maintenance or at-power preventive maintenance. Although the frequency and duration of the completion time may be estimated with the resulting unavailability calculated, discuss the effects that additional testing at power might have on plant risk due to improper maintenance or additional testing required that would have previously been performed during shutdown and not directly related to the extended completion time itself. Studies have shown that restoration failures have the potential to initiate a second loss of power that is difficult to diagnose and recover when that restoration was not always performed in accordance with established procedures.

WOG Response: The CT increase for the diesel generators is the proposed change that will be primarily used by the utilities for performing preventive maintenance activities during power operation. The other CT extensions proposed will be primarily used to provide additional time to perform troubleshooting and component repair during power operation.

As stated in the Bases for Technical Specification 3.8 (Electrical Power Systems) of NUREG-1431, Rev. 2, the AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The surveillance requirements for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9, Regulatory Guide 1.108, and Regulatory Guide 1.137, as addressed in the FSAR.

The issues in this RAI are related to the availability of the DG following additional at-power preventive maintenance activities and also the potential for inducing electrical system transients during the preventive maintenance activities or during the post maintenance testing. As stated in the previous paragraph, surveillance requirements on the AC sources are designed in accordance with the noted Regulatory Guides to ensure OPERABILITY of the DGs. These issues are addressed as follows:

- After maintenance activities, components/systems are subject to post maintenance testing and system alignment verification. Both are directed at demonstrating that the system is operable and will perform as required if demanded. These tests are performed regardless of the mode in which the testing is completed. Following the DG at-power maintenance activity, a test will be completed to demonstrate operability of the DG. This test is typically the monthly DG test required in plant Technical Specifications. This monthly test is designed to be performed with the plant at-power and demonstrates DG operability.
- DG maintenance activities are completed with the DG disconnected from the plant electrical distribution system. This configuration inhibits electrical transients from being introduced into the plant's electrical system.

- The testing is typically completed in a configuration that will not induce electrical system transients. The test used to demonstrate DG operability is the same as that used to meet the Technical Specification monthly test requirement. This test is designed to be performed at-power and not introduce electrical system transients that could impact plant operation.

The licensees requesting this change will confirm the above in their LAR submittals. Information to be provided by each licensee includes:

- The test that will be used following at-power maintenance activities to demonstrate DG operability.

- Confirmation that the DG is disconnected from the plant's electrical system during at-power preventive maintenance activities.

- The precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during the maintenance activity or follow-on testing.

WCNOC Response: Procedure AP 22C-003, "Operational Risk Assessment Program," provides guidance for the assessment and management of operational risks inherent with scheduling of system/component maintenance, testing and outages. This procedure provides guidance for risk assessments of maintenance and testing activities at WCGS in accordance with the requirements of 10 CFR 50.65. At WCGS, the Operational Risk Assessment Program for on-line daily maintenance and testing activities shall be 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:

- Ensuring systems, structures, and components (SSCs) are maintained to support key functions necessary for safe shutdown, accident mitigation, and commercial operation.
- Plan and schedule daily work activities in a manner that optimizes SSCs availability.
- Developing compensatory measures to manage and minimize the operational risks associated with planned or emergent activities that are categorized as risk significant by this procedure.
- 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.
- Preplan and sequence maintenance activities to minimize repeated entries of Technical Specification Limiting Conditions for Operation action statements and to control system out of service time.
- Maintaining a high degree of confidence that, prior to removing train related or redundant equipment from service, that backup equipment will remain available. The aggregate health of the train or component that will serve as the backup shall be greater than the one to be removed from service.
- 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.

Procedure AP 21E-001, "Clearance Orders," covers the use of Do Not Operate tags. The procedure provides a tagging method to ensure personnel safety, equipment protection, and to establish administrative controls when deemed necessary by the Operations department. The procedure provides guidance on how to properly isolate systems or components to ensure proper protection of personnel, equipment protection and isolation from operating systems.

- After maintenance activities, components/systems are subject to post maintenance testing and system alignment verification. Both are directed at demonstrating that the system is operable and will perform as required if demanded. These tests are performed regardless of the mode in which the testing is completed.

Following maintenance either procedure SYS KJ-123, "Post Maintenance Run of Emergency Diesel Generator A," or SYS KJ-124 "Post Maintenance Run of Emergency Diesel Generator B" will be performed. The purpose of these procedures is to provide instructions for verifying system alignment and performing maintenance runs of the DGs prior to performing surveillance OPERABILITY runs. The procedures provide instructions to perform the following activities:

- Roll the DG engine to check for fluid in the cylinders.
- Air rolls the DG engine to prime the fuel system following maintenance on the fuel system.
- Start the DG engine locally at slow speed (below synchronous) under governor control.
- Start and load the DG as required to perform maintenance checks following periods of extensive work
- Single air start tests of the starting system.
- Over speed testing of the DG if required.
- Resetting the DG engine high and low speed stops after adjusting for over speed testing or other reasons.

If work is performed on the DG governor system procedures MPE NE-003, "Governor Adjustments for Emergency Diesel Generator NE01," or MPE NE-002, "Governor Adjustments for Emergency Diesel Generator NE02," will be performed. The purpose of these procedures is to provide instructions for setting up and testing of the governor system.

- Following the DG at-power maintenance activity, a test will be completed to demonstrate OPERABILITY of the DG. This test is typically the monthly DG test required by Technical Specifications. The monthly test is designed for performance with the plant at-power to demonstrate DG OPERABILITY and completed in a configuration that will not induce electrical system transients.

There are separate procedures for performing either a slow or fast start of the DGs. Which procedure used will depend on the maintenance work performed and/or surveillance test which is due. This monthly test is designed for performance with the plant at-power and demonstrates DG OPERABILITY. Surveillance test procedures STS KJ-005A "Manual/Auto Start Synchronization & Loading of Emergency D/G NE01," or STS KJ-005B "Manual/Auto Start Synchronization & Loading of Emergency D/G NE02," cover the slow starting and loading of the DGs. Surveillance test procedures STS KJ-015A, "Manual/Auto Fast Start Sync & Loading of EDG NE01," or STS KJ-005B "Manual/Auto Fast Start Sync & Loading of EDG NE02," cover the fast starting and loading of the DGs.

RAI 12. WCAP-15622 discusses the risk impact of moving diesel maintenance activities from shutdown to at-power operation. WCAP-15622 found that performing scheduled maintenance activities at-power results in ICCDPs significantly smaller than for shutdown. The conclusion presented by WCAP-15622 were based on the analysis for one plant and were expected to be applicable for all plants that schedule EDG maintenance at the beginning of the outage. It is not clear that a neutral or net risk impact improvement will result from the proposed shift to on-line EDG maintenance. While a qualitative argument could be made with regard to performing maintenance on-line as opposed to shutdown, it is not clear that a quantitative argument applicable to all plants would be bounding. Previous studies (NUREG/CR-5994) have indicated that with respect to CDF, taking an EDG out-of-service for maintenance during the early stages of an outage is comparable to short interval maintenance performed during power operation. However, the likelihood of core damage can be reduced substantially by scheduling long duration maintenance during refueling when decay heat is low as opposed to power operation. The staff also notes that the standard TSs do not differentiate when work may be performed (what plant state) and therefore any risk averted by performing maintenance during power operation is problematic. Provide a discussion as to the generic applicability of WCAP-15622 results including plants without low power shutdown risk models.

WOG Response: Numerous scheduling schemes can be developed for completing DG maintenance during an outage. Section 8.2.6 of the WCAP provides one scheme used by Comanche Peak. This involves removing the DG from service in Mode 5. The purpose of providing this information is to demonstrate that these activities are not risk free. Section 8.2.6 also discusses, on a qualitative basis, the possible risk of doing these activities while shutdown. As discussed, if DG maintenance activities are completed in Mode 6, then the primary issue is loss of decay heat removal following a loss of offsite power event. Decay heat removal is important and can only be provided by the residual heat removal system that requires AC power for operation. AC power will be available, but degraded when one DG is out of service.

The placement of DG maintenance in the outage schedule is dependent on several elements including other activities that are planned for the outage and the planned outage length. DG maintenance activities can become critical path items to an outage. To eliminate this as a critical path element, it may be necessary to initiate the activities in Mode 5, which, as noted above, is in compliance with the Technical Specifications.

The risk results provided in Section 8.2.6 are applicable to other plants that also begin DG outages in Mode 5. The absolute values of the ICCDPs provided will vary depending on the plant, but in general, plant specific results would also show similar results, that is, a non negligible risk. But these plants may also defer removing DGs from service until later in the outage when the risk level is lower.

The point is, the risk of doing DG maintenance in the outage is not risk free and needs to be considered, at least qualitatively, in the decision process. The level of risk will change from outage-to-outage and also from plant-to-plant, depending on the utility's outage approach. But, the exact value is not crucial. As demonstrated in the WCAP and in responses to RAIs #8 and #16, the impact of the CT increase on risk (CDF, LERF, ICCDP, and ICLERP) meets the guidelines provided in Regulatory Guides 1.174

and 1.177, therefore, the argument for the acceptability of this change is based on the low impact of this change on at-power plant risk, not the tradeoff with shutdown risk.

WCNOC Response: WCGS has a shutdown PSA, although it is not fully documented and therefore will not be used quantitatively herein. The insights from the use of the shutdown model emphasize the importance and significance of reliable power for all activities. Reliable electrical power is extremely important during refueling outages. Switchyard activities must be carefully integrated into refueling outage schedules. While the point is taken in the question, there is merit to focusing resources to one task of short duration. Defense-in-depth reviews of multiple versus minimal maintenance activities are likely to come to the same conclusion.

RAI 13. The TR does not discuss whether each EDG at a plant is equivalent from a risk perspective when taken out of service. Discuss any differences and the impact on the TR conclusions. Additionally, discuss whether combining plant reliability data that may obscure the performance of individual EDGs at multi-unit sites.

WOG Response: Only a portion of the WOG response in letter OG-02-052 is provided. The following discusses the equivalence of the diesel generators and the reliability of the individual EDGs. Information provided includes RAW values for each DG, DG reliability history, list of loads on each DG, and a concluding statement of why the results are applicable to both (all) DGs.

WCNOC Response: The following discusses the equivalence of the DGs and the reliability of the individual DGs. Information provided includes RAW values for each DG, DG reliability history, list of loads on each DG, and a concluding statement of why the results are applicable to both (all) DGs.

1. <u>DG RAW values</u>

The RAW values for the DG test/maintenance basic events are:
NE01 (DG1): 5.42
NE02 (DG2): 4.29

2. <u>Reliability information for each DG</u>

WCGS has incurred the following DG failures over the five year period from 1/1/90 to 12/31/94:

NE01: One (1) failure to start over 183 start demands. (Corresponding failure rate is 5.41E-03 per demand.) No failures to run.

NE02: One (1) failure to start over 185 start demands. (Corresponding failure rate is 5.46E-03 per demand.)

NE02: One (1) failure to run over 145 hours of run time. (Corresponding failure rate is 6.9E-03 per hour.)

Formal collection and incorporation of failure data for the years 1995 to 1998 was beyond the scope of the 1998 failure update. However, the Maintenance Rule failure database was reviewed and whenever a noticeable degradation in plant failure data was observed relative to the data contained in AN-96-063, an effort was made to incorporate the recent failure data. This was not necessary because the failure data was satisfactory or seemed to be on an improving trend relative to the historical data.

3. List of loads on each DG

USAR Figure 8.3-2-00, "Wolf Creek, List of Loads Supplied by the Emergency Diesel Generator," summarizes the DG loads. A review shows that the loads on the DGs are essentially symmetrical. Some of the loads on each DG that are modeled in the WCGS PSA are provided in the following table:

Table RAI 13-1
Key DG Loads for WCGS

System/Train/Component	DG NE01	DG NE02
Motor Driven Auxiliary Feedwater Pump	A	B
Residual Heat Removal Pump	A	B
Essential Service Water Pump	A	B
Component Cooling Water Pump	A, C	B, D
Fuel Oil Transfer Pump	A	B
Centrifugal Charging Pump	A	B
Battery Chargers	NK21, 23, 25	NK22, 24, 26
Class 1E Equipment A/C	A	B
Containment Spray Pump	A	B
Containment Coolers	A, C	B, D

4. Discussion on Applicability of Results to Both DGs

The WCGS risk calculation results supporting the DG Completion Time extension are applicable to both DGs for the following reasons:

- The RAW values for the DGs are essentially the same. Slightly different RAWs may be observed depending on which train is in service. In a zero test and maintenance mode, the RAWs are different in the third significant figure. Therefore, the values for the risk metrics calculated using DG NE01 will bound the corresponding values for DG NE02.
- The loads on the DGs are essentially symmetrical.
- WCGS specific data shows that both DGs have exhibited similar reliability performance, as noted above, with respect to failures to start and failures to run.

RAI 16. Large early release frequency (LERF) or incremental conditional large early release probability (ICLERP) is not presented in WCAP-15622. Please provide results and a discussion.

WOG Response: Only a portion of the WOG response in letter OG-02-052 is provided. Tables RAI 16-1, RAI 16-2, and RAI 1-3 provide the LERF and ICLERP values for Callaway, Comanche Peak, McGuire, and Sequoyah for the CT increases of interest.

WCNOC Response: The below Table RAI 16-1 provides the LERF and ICLERP values for WCGS for the Completion Time increases of interest. The following discusses these results.

The WCGS results show that the impact on LERF for extending the DG Completion Time to 7 days for only scheduled activities meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP for scheduled activities meets the acceptance guideline in Regulatory Guide 1.177 (less than 5E-08). In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF. As previously discussed, restrictions on activities that could impact the reliability of the switchyard while a DG is out of service will be implemented, and DG outage activities will be planned during favorable weather periods. These restrictions have been accounted for in the calculations providing the LERF impact and ICLERP values.

Table RAI 16-1
Impact of DG Completion Time Increase on Large Early Release Related Parameters

Parameter	**Completion Time[1]**
	7 days
LERF (72 hr Completion Time) (per yr)	7.735E-07
LERF (extended Completion Time) (per yr)	7.842E-07
LERF Increase (per yr)	1.070E-08
CLERF (DG in test or scheduled maintenance) (per yr)	1.169E-06
ICLERP (DG in test or scheduled maintenance)	1.070E-08

Note 1: As discussed previously, WCGS is requesting the Completion Time extension only for scheduled activities and plans on implementing restrictions on activities that could impact the reliability of the switchyard and will plan DG outage activities during a favorable weather period. These restrictions have been accounted for in the calculations to determine the large early release parameters provided above.

RAI 17. Discuss considerations to prohibit entry or termination of an extended AOTs (maintenance) should external event conditions or warnings exist.

WOG Response: Only the DG CT extension will be used primarily to perform additional preventive maintenance activities when the plant is at-power. This type of activity is planned in advance and licensees can take precautions to reduce the probability of a loss of offsite power event from occurring when operating with a DG unavailable due to maintenance. External event conditions that are important with regard to loss of offsite power events are conditions that can impact the availability of offsite power to the plant. Of specific interest in this study is severe weather conditions.

To address this, utilities implementing the DG CT extension and crediting a reduced LOSP initiating event frequency, due to weather related restrictions, will develop a procedure or include restrictions in appropriate procedures or in their configuration risk management program as part of Maintenance Rule implementation (if such restrictions do not already exist) to prohibit entry into the CT for preventive maintenance activities if severe weather is forecast. In addition, if DG preventive maintenance is ongoing and severe weather is forecast, the procedures will require the DG to be restored to service as soon as possible. Affected licensees will develop and implement a procedure or appropriate guideline, if not already addressed by the Maintenance Rule, to meet this restriction. In addition, the severe weather restriction will also be included in the list of Tier 2 restrictions identified by the licensees.

WCNOC Response: Subsection 4.1.1.2 of Attachment I provides a discussion of weather related restrictions and is included in the list of Tier 2 restrictions.

EP RAI 3. The first bullet in Section 7.1 conveys that the likelihood of a transient occurring during the increased CT for an ac onsite electric power system has not been impacted and that some new activities may be performed on the diesel generators (DG) while at power. Explain how and why these new activities will not affect or impact the likelihood of maintenance or test induced transients.

WOG Response: A similar question was asked in PRA RAI #11 and a response provided. This response is provided in the following.

As stated in Bases B3.8 (Electrical Power Systems) of the Standard Technical Specifications for Westinghouse Plants (NUREG 1431, Rev. 2), the AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The surveillance requirements for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9, Regulatory Guide 1.108, and Regulatory Guide 1.137, as addressed in the FSAR.

The issues in this RAI are related to the availability of the DG following additional at-power preventive maintenance activities and also the potential for inducing electrical system transients during the preventive maintenance activities or during the post maintenance testing. As stated in the previous paragraph, surveillance requirements on the AC sources are designed in accordance with the noted Regulatory Guides to ensure OPERABILITY of the DGs. These issues are addressed as follows:

- After maintenance activities, components/systems are subject to post maintenance testing and system alignment verification. Both are directed at demonstrating that the system is operable and will perform as required if demanded. These tests are performed regardless of the mode in which the testing is completed.

- DG maintenance activities are completed with the DG disconnected from the plant electrical distribution system. This configuration inhibits electrical transients from being introduced into the plant's electrical system.

- The testing is typically completed in a configuration that will not induce electrical system transients. The test used to demonstrate DG operability is the same as that used to meet the Technical Specification monthly test requirement. This test is designed to be performed at-power and not introduce electrical system transients that could impact plant operation.

The licensees requesting this change will confirm the above in their License Amendment Request (LAR) submittals. Information to be provided by each licensee includes:

- The test that will be used following at-power maintenance activities to demonstrate DG operability.
- Confirmation that the DG is disconnected from the plant's electrical system during at-power preventive maintenance activities.

- The precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during the maintenance activity or follow-on testing.

WCNOC Response: Following maintenance, either procedure SYS KJ-123, "Post Maintenance Run of Emergency Diesel Generator A," or SYS KJ-124, "Post Maintenance Run of Emergency Diesel Generator B," will be performed. The purpose of these procedures is to provide instructions for verifying system alignment and performing maintenance runs of the DGs prior to performing surveillance OPERABILITY runs. The procedures provide instructions to perform the following activities.

- Roll the DG engine to check for fluid in the cylinders.

- Air rolls the DG engine to prime the fuel system following maintenance on the fuel system.

- Start the DG engine locally at slow speed (below synchronous) under governor control.

- Start and load the DG as required to perform maintenance checks following periods of extensive work

- Single air start tests of the starting system.

- Over speed testing of the DG if required.

- Resetting the engine high and low speed stops after adjusting for over speed testing or other reasons.

If work is performed on the governor system, procedures MPE NE-003, "Governor Adjustments for Emergency Diesel Generator NE01," or MPE NE-002, "Governor Adjustments for Emergency Diesel Generator NE02," will be performed. The purpose of these procedures is to provide instructions for setting up and testing of the governor system.

Procedure AP 21E-001 "Clearance Orders," covers the use of Do Not Operate tags. The procedure provides a tagging method to ensure personnel safety, equipment protection, and to establish administrative controls when deemed necessary by the Operations department. The procedure provides guidance on how to properly isolate systems or components to ensure proper protection of personnel, equipment protection and isolation from operating systems.

There are separate procedures for performing either a slow or fast start of the DGs. Which procedure used will depend on the maintenance work performed and/or surveillance test which is due. This monthly test is designed for performance with the plant at-power and demonstrates DG OPERABILITY. Surveillance test procedures STS KJ-005A "Manual/Auto Start Synchronization & Loading of Emergency D/G NE01," or STS KJ-005B "Manual/Auto Start Synchronization & Loading of Emergency D/G NE02," cover the slow starting and loading of the DGs. Surveillance test procedures STS KJ-015A, "Manual/Auto Fast Start Sync & Loading of EDG NE01," or STS KJ-005B "Manual/Auto Fast Start Sync & Loading of EDG NE02," cover the fast starting and loading of the DGs.

MARKED-UP TECHNICAL SPECIFICATIONS

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 6 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	------------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		
			(continued)

------- 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 for an inoperable DG.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	---------NOTE--------- The Required Action of B.3.2 is satisfied by the automatic start and sequence loading of the DG. ------------------------	
		Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		
	B.4	Restore DG to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO

------NOTE------
A Completion Time of 7days and 10 days from discovery of failure to meet the LCO may be used once per cycle per DG.

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. NG05E or NG06E inoperable.	A.1	Enter applicable Condition and Required Action of LCO 3.7.8, "Essential Service Water (ESW) System" for ESW train without electrical power.	Immediately
B. One AC electrical power distribution subsystem other than NG05E or NG06E inoperable.	B.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours AND 34 16 hours from discovery of failure to meet LCO
C. One AC vital bus subsystem inoperable.	C.1	Restore AC vital bus subsystem to OPERABLE status.	24 2 hours AND 34 18 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One DC electrical power distribution subsystem inoperable.	D.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 34 16 hours from discovery of failure to meet LCO
E. Required Action and associated Completion Time not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 5.	36 hours
F. Two trains with inoperable distribution subsystems that result in a loss of safety function.	F.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

PROPOSED/REVISED TECHNICAL SPECIFICATIONS

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 LCO may be used with the 7 day Completion Time of Required Action B.4 for an inoperable DG. ------------------------ 72 hours AND 6 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
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	-----------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.3.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	-----------NOTE----------- The Required Action of B.3.2 is satisfied by the automatic start and sequence loading of the DG. ------------------------------ Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.4	Restore DG to OPERABLE status.	---------NOTE-------- A Completion Time of 7 days and 10 days from discovery of failure to meet LCO may be used once per cycle per DG. ------------------------ 72 hours <u>OR</u> 6 days from discovery of failure to meet LCO
C. Two offsite circuits inoperable.	C.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 C concurrent with inoperability of redundant required features
	<u>AND</u>		
	C.2	Restore one offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. 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 D is entered with no AC power source to any train. --------------- D.1 Restore offsite circuit to OPERABLE status. OR D.2 Restore DG to OPERABLE status.	 12 hours 12 hours
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. One load shedder and emergency load sequencer inoperable.	F.1 Declare affected DG and offsite circuit inoperable. AND F.2 Restore load shedder and emergency load sequencer to OPERABLE status.	Immediately 12 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours
H. Three or more required AC sources inoperable.	H.1 Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. NG05E or NG06E inoperable.	A.1 Enter applicable Condition and Required Action of LCO 3.7.8, "Essential Service Water (ESW) System" for ESW train without electrical power.	Immediately
B. One AC electrical power distribution subsystem other than NG05E or NG06E inoperable.	B.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours <u>AND</u> 34 hours from discovery of failure to meet LCO
C. One AC vital bus subsystem inoperable.	C.1 Restore AC vital bus subsystem to OPERABLE status.	24 hours <u>AND</u> 34 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One DC electrical power distribution subsystem inoperable.	D.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 34 hours from discovery of failure to meet LCO
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours
F. Two trains with inoperable distribution subsystems that result in a loss of safety function.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

TS BASES CHANGES
(For Information Only)

BASES

ACTIONS

A.2 (continued)

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 total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, ~~the circuit restored OPERABLE~~ and an additional 72 hours ~~for a total of 9 days~~ allowed prior to complete restoration of the LCO. This could continue indefinitely if not limited. The 6 day Completion Time provides a limit on the time allowed in a specified

This limits the time the plant can alternate between Conditions A, B, and D (see Completion Time Example 1.3-3).

ACTIONS

A.3 (continued)

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. 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.

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

INSERT A

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.

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 systems. These features are designed with redundant safety related trains. 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.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This

INSERT A

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 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 Note in Condition B.

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 Note 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. 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).

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 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 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.

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.

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.4

INSERT B

~~According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.~~

~~In Condition B, the remaining OPERABLE DG and offsite circuits 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 B.4 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, ~~and that circuit is subsequently restored OPERABLE~~ 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 DG~~ compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable, ~~the DG restored OPERABLE~~ and an additional 72 hours ~~(for a total of 9 days)~~ allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. This limits the time the plant can alternate between Conditions A, B, and D (see Completion Time Example 1.3-3). This could occur indefinitely if not limited. 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.

BASES

ACTIONS

B.4 (continued)

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

INSERT C

C.1 and C.2

Required Action C.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 safety functions. 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. 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 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.

The Completion Time for Required Action C.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.

INSERT B

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 applies when a DG is discovered or determined to be inoperable, such as due to a component 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.

INSERT C

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 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 7 days once per cycle for each DG. The Note only applies when a DG is declared or rendered inoperable for the performance of voluntary, planned maintenance activities. The 7-day Completion Time is a risk-informed allowed outage time (AOT) based on a plant-specific risk analysis using the methodology in WCAP-15622 (Ref. 14). The Completion Time provided in the Note was established on the assumption that it would be used only for voluntary planned maintenance, inspections and testing. Use of the Note is limited to once within an operating cycle (18 months) for each DG. Administrative controls applied during use of the Note for voluntary planned maintenance activities ensure or require that:

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

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

c. Sharpe Station is available to provide greater than 8 MW power to a dead bus (station blackout conditions) to power 1 ESF train.

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 the Note is being used, one (or more) of the above systems or components is determined or discovered to be inoperable, or if 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 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 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. 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 D (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 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 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.

BASES

ACTIONS

B.1 (continued)

Condition B worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of :

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

also

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition ~~A~~ B is entered while, for instance, a DC bus is inoperable (Condition D) and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a ~~DC circuit~~ vital bus could ~~again~~ become inoperable ~~and AC distribution restored OPERABLE~~ INSERT B-1. This could continue indefinitely if not limited.

INSERT B-2

~~The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

C.1

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE

INSERT B-1

and an additional 24 hours allowed prior to complete restoration of the LCO, for a total of 34 hours.

INSERT B-2

The 34 hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B, C, and D are entered concurrently. The "AND" connector between the 8 hour and 34 hour Completion Times mean that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the 34 hour 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 34 hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 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 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

BASES

ACTIONS

C.1 (continued)

24

status within 2 hours by powering the bus from the associated inverter via inverted DC or Class 1E constant voltage (Sola) transformer.

Condition C represents one AC vital bus without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected vital bus.

24 some

This 2 hour limit is more conservative than Completion Times allowed for ~~the vast majority of~~ components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

24

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

24

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

and is justified based on the methodology in WCAP-15622 (Ref. 4)

also

The second Completion Time for Required Action C.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable ~~and subsequently returned OPERABLE~~, the LCO may already have been not met for up to 8 hours. ~~This~~ could lead to a total of 10 hours, since initial failure of the LCO, to restore the vital bus ~~distribution system~~. At this time, ~~an AC train~~ could ~~again~~ become

time

(Condition B)

If the AC bus is restored to OPERABLE status within the required 2 hours, this

32

to restore compliance with the LCO, (i.e.,

to meet

a DC bus

BASES

ACTIONS

C.1 (continued)

and an additional 2 hours allowed prior to complete restoration of the LCO, for a total of 34 hours.

inoperable ~~and vital bus distribution restored OPERABLE.~~ This could continue indefinitely if not limited.

INSERT B-3

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

D.1

With DC bus(es) in one train inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition D represents one train without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

INSERT B-3

The 34 hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B, C, and D are entered concurrently. The "AND" connector between the 8 hour and 34 hour Completion Times mean that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the 34 hour 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 34 hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 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 C "time zero," and the "time zero" when LCO 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

BASES

ACTIONS

D.1 (continued)

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action D.1 also establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition D is entered while, for instance, an AC bus is inoperable (Condition B) and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, ~~an AC train~~ a vital bus could ~~again~~ become inoperable~~, and DC distribution restored OPERABLE. This could continue indefinitely.~~ INSERT B-4

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~ INSERT B-5

E.1 and E.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, 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.

INSERT B-4

and an additional 24 hours allowed prior to complete restoration of the LCO, for a total of 34 hours. This could continue indefinitely if not limited.

INSERT B-5

The 34 hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B, C, and D are entered concurrently. The "AND" connector between the 8 hour and 34 hour Completion Times mean that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the 34 hour 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 34 hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 was initially not met, instead of at the time Condition D was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition C "time zero," and the "time zero" when LCO 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

LIST OF COMMITMENTS

The following table identifies those actions committed to by Wolf Creek Nuclear Operating Corporation (WCNOC) in this document. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. Kevin Moles, Manager Regulatory Affairs at Wolf Creek Generating Station, (620) 364-4126.

COMMITMENT	Due Date/Event
Revision to the TS Bases will be implemented pursuant to the TS Bases Control Program, TS 5.5.14, upon implementation of this license amendment.	Within 90 days of NRC approval.
the license amendment will be implemented within 90 days from the date of issuance.	Within 90 days of NRC approval.
The logic for breaker 69-4 will be modified to close with the line side energized and the 69 kV bus de-energized.	Prior to implementation of amendment
Additional compensatory measures and configuration risk management controls that will apply when entering the proposed planned, extended DG Completion Time (greater than 72 hours and up to 7 days) include: • Perform work during a favorable weather period (Sept. 6 through April 22) • Weather forecast checked for severe weather conditions • Elective testing and maintenance activities are precluded in the WCGS switchyard that could cause a line outage or challenge offsite power availability • Additional AC power Sharpe Station available and performance acceptable • Concurrent work on other key SSCs is not planned (Essential Service Water System, Component Cooling Water System, Motor/Turbine Driven Auxiliary Feedwater Pumps, Residual Heat Removal System) While in the proposed extended DG Completion Time, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.	Prior to implementation of amendment