May 30, 2007

Mr. Michael D. Wadley
Site Vice President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: EXTENSION OF TECHNICAL SPECIFICATIONS 3.8.1 "AC SOURCE-OPERATING," EMERGENCY DIESEL GENERATOR (EDG) COMPLETION TIME (TAC NOS. MC9001 AND MC9002)

Dear Mr. Wadley:

The Commission has issued the enclosed Amendment No. 178 to Facility Operating License No. DPR-42 and Amendment No. 168 to Facility Operating License No. DPR-60 for the Prairie Island Nuclear Generating Plant, Units 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated November 21, 2005, supplemented by letters dated June 16, August 31, September 29, and October 30, 2006, March 15, and May 10, 2007.

The amendments extend the Required Action Completion Times (CT) specified in TS 3.8.1, "AC Sources -Operating," to restore an inoperable EDG to operable status from the current 7 days to 14 days. Specifically, the proposed changes would revise the current 7-day CT specified in TS 3.8.1 Required Action B.4 to allow 14 days to restore an inoperable EDG to operable status.

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Mahesh L. Chawla, Project Manager
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-282 and 50-306

Enclosures:
1. Amendment No. 178 to DPR-42
2. Amendment No. 168 to DPR-60
3. Safety Evaluation

cc w/encls: See next page

May 30, 2007

Mr. Michael D. Wadley
Site Vice President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: EXTENSION OF TECHNICAL SPECIFICATIONS 3.8.1 "AC SOURCE-OPERATING," EMERGENCY DIESEL GENERATOR (EDG) COMPLETION TIME (TAC NOS. MC9001 AND MC9002)

Dear Mr. Wadley:

The Commission has issued the enclosed Amendment No. 178 to Facility Operating License No. DPR-42 and Amendment No. 168 to Facility Operating License No. DPR-60 for the Prairie Island Nuclear Generating Plant, Units 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated November 21, 2005, supplemented by letters dated June 16, August 31, September 29, and October 30, 2006, March 15, and May 10, 2007.

The amendments extend the Required Action Completion Times (CT) specified in TS 3.8.1, "AC Sources -Operating," to restore an inoperable EDG to operable status from the current 7 days to 14 days. Specifically, the proposed changes would revise the current 7-day CT specified in TS 3.8.1 Required Action B.4 to allow 14 days to restore an inoperable EDG to operable status.

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/RA/
Mahesh L. Chawla, Project Manager
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-282 and 50-306

Enclosures:
1. Amendment No. 178 to DPR-42
2. Amendment No. 168 to DPR-60
3. Safety Evaluation

cc w/encls: See next page

DISTRIBUTION

PUBLIC	LPL3-1 r/f	RidsNrrDorlLpl3-1	RidsNrrPMMChawla
RidsNrrLATHarris	RidsOGCRp	RidsAcrsAcnwMailCenter	RidsNrrDirsltsb
G. Hill, OIS	RidsRgn3MailCenter		GWilson
RidsNrrDorlDpr	OChopra	OHopkins	SLaur
MRubin	TKobetz	Rclark	

Adams Accession Number: ML071310023, Package: ML071490003, TS: ML071490004

OFFICE	NRR/LPL3-1/PM	NRR/LPL3-1/LA	EEEB:BC	APLA:BC	ITSB:BC	OGC/NLO w/comts	NRR/LPL3-1/BC
NAME	MChawla	THarris	GWilson	MRubin	TKobetz	JRund	L Raghavan
DATE	5/29/07	5/11/07	5/15/07	5/29/07	5/29/07	5/23/07	5/30/07

OFFICIAL RECORD COPY

Prairie Island Nuclear Generating Plant,
Units 1 and 2

cc:

Jonathan Rogoff, Esquire
Vice President, Counsel & Secretary
Nuclear Management Company, LLC
700 First Street
Hudson, WI 54016

Manager, Regulatory Affairs
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

Manager - Environmental Protection Division
Minnesota Attorney General's Office
445 Minnesota St., Suite 900
St. Paul, MN 55101-2127

U.S. Nuclear Regulatory Commission
Resident Inspector's Office
1719 Wakonade Drive East
Welch, MN 55089-9642

Regional Administrator, Region III
U.S. Nuclear Regulatory Commission
Suite 210
2443 Warrenville Road
Lisle, IL 60532-4351

Administrator
Goodhue County Courthouse
Box 408
Red Wing, MN 55066-0408

Commissioner
Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2198

Tribal Council
Prairie Island Indian Community
ATTN: Environmental Department
5636 Sturgeon Lake Road
Welch, MN 55089

Nuclear Asset Manager
Xcel Energy, Inc.
414 Nicollet Mall, R.S. 8
Minneapolis, MN 55401

Michael B. Sellman
President and Chief Executive Officer
Nuclear Management Company, LLC
700 First Street
Hudson, MI 54016

Douglas E. Cooper
Senior Vice President and Chief
Nuclear Officer
Nuclear Management Company, LLC
700 First Street
Hudson, WI 54016

NUCLEAR MANAGEMENT COMPANY, LLC

DOCKET NO. 50-282

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 178
License No. DPR-42

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Nuclear Management Company, LLC (the licensee), dated November 21, 2005, supplemented by letters dated June 16, August 31, September 29, and October 30, 2006, March 15, and May 10, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-42 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 178, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

L. Raghavan, Chief
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility Operating License
and Technical Specifications

Date of Issuance: May 30, 2007

NUCLEAR MANAGEMENT COMPANY, LLC

DOCKET NO. 50-306

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 168
License No. DPR-60

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Nuclear Management Company, LLC (the licensee), dated November 21, 2005, supplemented by letters dated June 16, August 31, September 29, and October 30, 2006, March 15, and May 10, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-60 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 168, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

L. Raghavan, Branch Chief
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Facility Operating License
and Technical Specifications

Date of Issuance: May 30, 2007

ATTACHMENT TO LICENSE AMENDMENT NOS. 178 AND 168

FACILITY OPERATING LICENSE NOS. DPR-42 AND DPR-60

DOCKET NOS. 50-282 AND 50-306

Replace the following pages of the Facility Operating License No. DPR-42 and DPR-60 with the attached revised pages. The changed areas are identified by a marginal line.

REMOVE	INSERT
DPR-42, License Page 3	DPR-42, License Page 3
DPR-60, License Page 3	DPR-60, License Page 3

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT
3.8.1-2	3.8.1-2
3.8.1-3	3.8.1-3

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, NMC to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, NMC to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility;

(6) Pursuant to the Act and 10 CFR Parts 30 and 70, NMC to transfer byproduct materials from other job sites owned by Northern States Power Company for the purpose of volume reduction and decontamination.

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

NMC is authorized to operate the facility at steady state reactor core power levels not in excess of 1650 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No.178, are hereby incorporated in the license. NMC shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

NMC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Prairie Island Nuclear Generating Plant Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program," Revision 0, submitted by letter dated October 18, 2004.

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, NMC to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility;

(6) Pursuant to the Act and 10 CFR Parts 30 and 70, NMC to transfer byproduct materials from other job sites owned by Northern States Power Company for the purposes of volume reduction and decontamination.

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

NMC is authorized to operate the facility at steady state reactor core power levels not in excess of 1650 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No.168, are hereby incorporated in the license. NMC shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

NMC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: 'Prairie Island Nuclear Generating Plant Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program," Revision 0, submitted by letter dated October 18, 2004.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 178 TO FACILITY OPERATING LICENSE NO. DPR-42

AND AMENDMENT NO. 168 TO FACILITY OPERATION LICENSE NO. DPR-60

NUCLEAR MANAGEMENT COMPANY, LLC

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2

DOCKET NOS. 50-282 AND 50-306

1.0 INTRODUCTION

By letter dated November 21, 2005, supplemented by letters dated June 16, August 31, September 29, October 30, 2006, March 15, and May 10, 2007, Nuclear Management Company, LLC (the licensee) submitted a License Amendment Request (LAR), requesting a change to the Prairie Island Nuclear Generating Plant Unit 1 and 2 Facility Operating License in accordance with Title 10 of the *Code of Federal Regulations*, Part 50.90 (10 CFR 50.90). The supplements provided additional information that clarified the application, but did not expand the scope of the application as originally noticed and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 3, 2006 (71 FR 151).

The licensee proposed changes to Prairie Island Nuclear Generating Station (PINGP) Technical Specifications (TSs) related to emergency diesel generators (EDGs) to extend the Required Action Completion Times (CT) specified in TS 3.8.1, "AC Sources -Operating," to restore an inoperable DG to operable status from the current 7 to 14 days.

The purpose of the proposed change is to provide the licensee with needed flexibility in performing both corrective and preventive maintenance during power operation on EDGs. On February 1, 2006, the licensee met with the Nuclear Regulatory Commission (NRC) staff to discuss the amendment request. This was a post-submittal meeting with the staff to provide more information on the submittal and electrical distribution system at Prairie Island. On April 4, 2006, the NRC staff forwarded a request for additional information (RAI) to the licensee via e-mail (ADAMS Accession No. ML060950613). The licensee responded to the RAI by letter dated June 16, 2006. Based on this response, the NRC staff had additional questions concerning probabilistic risk assessment (PRA) which were discussed with the licensee on August 9, 2006, during a teleconference. There were additional teleconferences held with the licensee on August 22, and September 5, 2006, regarding load capabilities of the EDGs and the PRA aspects of the application.

On September 21, 2006, the licensee met with the NRC staff to further discuss the amendment request. The licensee presented information on the various loads that the EDGs would be subjected to during loss of offsite power (LOOP) and station blackout (SBO) events. The licensee presented the list of loads and the electrical schematics for the onsite distribution system at PINGP, Unit 1 and 2. At that time, the NRC staff requested that certain items of discussion be clarified on the docket. There were further follow-up telephone conversations held between the licensee and the staff on January 24, and April 5, 2007, regarding EDG loading, and testing requirements with respect to loadings and power factors used. In letters dated September 29, and October 30, 2006, March 15, and May 10, 2007, the licensee provided additional clarifications on the items discussed in the previous meetings and the subsequent telephone conversations.

The proposed CT extension is founded on the findings of both deterministic and PRA perspectives.

2.0 REGULATORY EVALUATION

2.1 Deterministic approach

PINGP, Unit 1 and 2 were designed and constructed to comply with the Atomic Energy Commission's "General Design Criterion for Nuclear Power Plant Construction Permits", as proposed on July 11, 1967 (32 FR 10213).

The regulatory requirements and guidance which the NRC staff applied in its review of the application include:

Draft General Design Criterion (GDC) 24, "Emergency Power for Protection Systems," requires that in the event of loss of all offsite power, sufficient alternate sources of power will be provided to permit the required functioning of the protection systems.

10 CFR 50.36, "Technical Specification," requires a licensee's TS include limiting conditions for operation (LCOs) and surveillance requirements (SRs) for equipment that is required for safe operation of the facility. Specifically, 10 CFR 50.36(c)(3) SRs.

Draft GDC 39, "Emergency Power for Engineered Safety Features," requires that alternate power systems will be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and a offsite power system will each, independently, provide this capacity assuming a failure of single active component in each power system.

10 CFR 50.63, "Loss of All Alternating Current Power" as it relates to the capability to withstand and recover from an SBO.

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires that in evaluating preventive maintenance activities, the overall availability of the systems, structures, and components is balanced against the objective of preventing failures of systems, structures, and components. It also requires that before performing maintenance

activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

Regulatory Guide (RG) 1.93, “Availability of Electric Power Sources,” provides guidance with respect to operating restrictions (i.e., CTs) if the number of available alternate current (AC) sources are less than that required by the TS LCOs. In particular, this guide prescribes a maximum CT of 72 hours for an inoperable onsite or offsite AC source. RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing-basis changes by considering engineering issues and applying risk insights. This regulatory guide also provides risk acceptance guidelines for evaluating the results of such evaluations.

2.2 Probabilistic Risk Assessment

The regulatory guidance which the NRC staff applied in its review of the application include:

1. RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," describes an acceptable risk-informed approach specifically for assessing proposed TS changes in allowed outage times (AOTs). (Note that the phrase “completion time” used in the PINGP TS is equivalent to the phrase “allowed outage time” used in RG 1.177.) This regulatory guide also provides risk acceptance guidelines for evaluating the results of such evaluations.

One acceptable approach to making risk-informed decisions about proposed TS changes is to show that the proposed changes meet five key principles stated in RG 1.174, Section 2 and RG 1.177, Section B:

1. The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.

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

3. The proposed change maintains sufficient safety margins.

4. When proposed changes result in an increase in core-damage frequency or risk, the increases should be small and consistent with the intent of the Commission’s Safety Goal Policy Statement.

5. The impact of the proposed change should be monitored using performance measurement strategies.

For permanent TS changes, RG 1.174 and RG 1.177 provide numerical risk acceptance guidelines that are helpful in determining whether or not the fourth key principle has been satisfied. These guidelines are not to be applied in an overly prescriptive manner; rather, they provide an indication, in numerical terms, of what is considered acceptable. The intent in comparing risk results with the risk acceptance guidelines is to demonstrate, with reasonable assurance, that the fourth key principle has been satisfied.

3.0 TECHNICAL EVALUATION

3.1 DETERMINISTIC EVALUATION

3.1.1 BACKGROUND

The PINGP safeguards distribution system AC sources consist of the offsite power sources and the onsite standby power sources (Train A and Train B EDGs). The onsite safeguards AC distribution system is divided into redundant trains so that the loss of anyone train does not prevent the minimum safety functions from being performed.

The output of the PINGP is delivered to a 345/161 kV Substation, which has five transmission lines. Four of these are 345 kV lines. The 345 kV portion is arranged in two buses with a breaker-and-one-half scheme. The 161 kV portion of the substation is a single bus arrangement connected to a single 161 kV transmission line. Three separate power systems are provided to the plant 4 kV safeguards buses. Each safeguards bus has two possible paths between it and the offsite transmission system.

Each safeguards bus has a normal and an alternate supply breakers from the offsite transmission system, and also a supply breaker from its associated EDG. Each safeguards bus also has two normally open bus tie breakers between itself and the same-train bus of the other unit.

Each PINGP unit is designed with two redundant 4 kV emergency buses. The onsite standby power source for each redundant 4 kV emergency bus is a dedicated EDG. The EDGs do not serve a function during normal plant operations. The normal power sources for the safeguards buses are the paths from the reserve auxiliary transformers and the cooling tower substation. If the reserve auxiliary transformers and the cooling tower substation paths should fail, backup power is provided by two EDGs in each unit.

Each EDG, as a backup to the normal standby AC power supply, is capable of sequentially starting and supplying the power requirements of one of the redundant sets of engineered safety features for its reactor unit. In addition, in the event of a SBO condition, each EDG is capable of sequentially starting and supplying the power requirements of the hot shutdown loads for its unit, as well as the essential loads of the blacked out unit, through the use of manual bus tie breakers interconnecting the buses.

The original plant design and construction included two Fairbanks-Morse opposed piston EDGs for the two unit site. These two diesels are now dedicated to Unit 1 to provide onsite standby power sources for 4 kV safeguards buses 15 and 16. The two Unit 1 EDGs are 4 kV, three phase, 2750 kW (continuous rating) synchronous generators.

In 1992, two Societe Alsacienne de Constructions Mecaniques de Mulhouse (SACM) EDGs, D5 and D6, were installed at PINGP Unit 2 to provide onsite standby power sources for 4 kV safeguards buses 25 and 26. Each SACM EDG comprises two tandem-drive diesel engines. The two Unit 2 EDGs are 4 kV, three phase, 5400 kW (continuous rating) synchronous generators. D5 and D6 are radiator cooled and thus independent of the plant safeguards cooling water system (similar to the service water system for other plants).

3.1.2 PROPOSED TS CHANGES

3.1.2.1 Diesel Generator Outage Time Extension

The proposed changes to TS 3.8.1 are as follows:

1. Condition A

The second CT to Required Action A.2 is revised from 14 days to 21 days. The second CT is there to limit the total time that LCO 3.8.1 is not met in Conditions A and B. Since the proposed request is to increase the EDG CT to 14 days, the new total time limit is 21.

Also, correction to a format error is proposed on page 3.8.1-2. A double line appears at the top of the ACTIONS table on this page. In accordance with TSTF-GG-05-01, "Writer's Guide for Plant-Specific Improved Technical Specifications," (previously known as NUMARC 93-03 and NEI 01 - 03, "Writer's Guide for the Improved Standard Technical Specifications"), double lines "Indicate the beginning and end of each Specifications Actions, SRs, or other table(s)." Since the ACTIONS table begins on the previous page, this double line will be replaced with a single line.

2. Condition B

The CT to Required Action B.4 is revised to state,"14 days AND 21 days from discovery of failure to meet LCO." These proposed changes will provide a CT extension for the PINGP EDGs from 7 days to 14 days.

3.1.3 DETERMINISTIC EVALUATION

Current TS 3.8.1, Condition B, Required Actions and associated CT require the inoperable EDG to be restored to operable status within 7 days or enter Condition F for which the required actions and CT require the plant to be in Mode 3 within 6 hours and mode 5 within 36 hours. The licensee has proposed to extend the CT for an inoperable EDG from the current 7 days to 14 days.

A minor format correction on the TS 3.8.1 Actions Table is also proposed. The NRC staff finds this minor correction to be acceptable. The main purpose of the proposed amendment is to extend the CT for EDGs from the current 7 days to 14 days. The licensee states that special EDG maintenance overhaul activities, such as periodic cylinder liner replacement, require more than 7 days to perform. Thus, these activities must be scheduled to be performed during a plant refueling outage to avoid shutdown due to the current 7 day CT. Extending the EDG CT to 14 days will allow more on-line special overhauls. The licensee intends to limit use of the extended CT for voluntary planned overhaul and vendor recommended inspections to once within an

operating cycle for each EDG. The licensee states that extending the CT for an inoperable EDG will provide the following benefits:

- Allows increased flexibility in the scheduling and performance of EDG preventive maintenance.

- Allows better control and allocation of resources. By allowing on-line preventive maintenance, including scheduled overhauls, provides the flexibility to focus more quality resources on any required or elective EDG maintenance.

- Improves EDG availability during shutdown. This should reduce the risk associated due to EDG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.

- Reduces the number of individual entries into required action statements by providing sufficient time to perform related maintenance tasks with a single entry.

PINGP's design satisfies SBO rule (10 CFR 50.63) by providing alternate ac (AAC) power source from the non-blacked out unit's EDGs within 10 minutes of the SBO event. The AAC power source to the blacked out unit will be a cross-tied EDG from the non-blacked-out unit. Connection of the AAC source for the blacked out unit, will be through manual bus tie breakers between buses of the same train on opposite units. After either EDG in the non-SBO unit has completed load sequencing and has provided power to the designated safeguards equipment, the operator will manually close two series bus tie breakers to the SBO unit's same-train safeguards bus. These breakers are normally open during plant operation and are administratively and procedurally controlled by the plant operating procedures. With the use of these two series breakers, with a complete loss of offsite power, any one EDG is able to provide power to its associated unit plus the same-train SBO loads of the other unit and remain within its continuous duty ratings. The licensee states that there is no single known component whose failure would cause the inoperability of both EDGs in a unit. Tests and analysis have shown that the non-SBO unit's EDG is available and the interconnecting bus ties can be closed within 10 minutes of the realization that an SBO condition exists. PINGP maintains an EDG reliability program based on RG 1.155, "Station Blackout." The program monitors and evaluates EDG performance and reliability consistent with guidance provided in NUMARC 87-00, "Guidelines for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors". The program requires remedial actions when one or more established reliability "trigger values" are exceeded, requires root cause evaluation, and requires corrective actions.

On February 1, 2006, the licensee met with NRC staff to discuss the amendment request to extend the completion time for EDGs at PINGP from 7 days to 14 days. The licensee provided background information on PINGP onsite and offsite power systems and described the design strengths of PINGP distribution system. The licensee also discussed the capabilities of EDGs as an AAC source for SBO mitigation. Licensee's presentation indicated that each of the EDGs has sufficient capacity to supply the SBO loads in the blacked-out and the required LOOP loads in the non-blacked out (NBO) unit. The NRC staff requested the licensee to provide information on the excess capacity of each EDG beyond its normally available safe shutdown capability for the LOOP loads to establish that the AAC power source has sufficient capacity to power not only its loads, but also the required loads of the inoperable EDG bus.

On September 21, 2006, a second meeting was held between the NRC staff and the licensee to discuss the capabilities of EDGs at PINGP to power not only its own unit's LOOP safe shutdown loads of one train, but also the other unit's inoperable EDG bus LOOP safe shutdown loads. The licensee presented information to demonstrate that each EDG at PINGP can bring both units to safe shutdown and maintain it there for an indefinite period of time. The licensee presented the shutdown evaluation by assuming Unit 1 in LOOP condition and Unit 2 in SBO and described the procedure to shutdown both units in parallel. The LOOP safe shutdown loads for Unit 1 are 1370 kW for Train A and 1702 kW for Train B. Similarly, the LOOP safe shutdown loads for Unit 2 are 2602 kW for train A and 2453 kW for Train B. The SBO loads for Unit 1 are 846 kW for Train A and 1199 kW for Train B and for Unit 2 are 756 kW for Train A and 922 kW for Train B. The maximum predicted load during a Unit 2 SBO on either D1 or D2, acting as the AAC source is the Mode 3, hot standby/LOOP load for its unit plus the SBO load from Unit 2 is 2624 kW. Similarly, for a Unit 1 SBO, the maximum predicted loads on D5 or D6 is 3652 kW. Each of these is within the continuous rating of the respective unit's EDG.

In addition to the above, the NRC staff reviewed the TS SR of the PINGP EDGs to determine their suitability for granting a 14 day CT extension and noted the following testing deficiencies could challenge the assurance that these EDGs can handle the above-mentioned loads:

SR 3.8.1.3 for EDGs D1 and D2 requires verification every month that each EDG is synchronized, loaded, and operated for ≥1650 kW. This loading is well below the maximum design basis loading of 2453 kW for these EDGs. On the other hand, a majority of the plants demonstrate full load carrying capability of their EDGs every month consistent with NUREG-1431, "Technical Specifications for Westinghouse Plants," and Regulatory Guide 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants." These documents require that every 31 days each EDG should be tested at 90 percent of continuous rating to demonstrate its full load carrying capability. The TS loading limit should envelope design accident loads. Since the design accident loading is 2453 kW, the limit should be ≥2453 kW in the TS.

In a conference call dated April 5, 2007, the NRC staff expressed its concerns to the licensee for not testing Unit 1 EDGs at or above 90 percent of its continuous rating. Subsequently, in a letter dated May 10, 2007, the licensee committed to submit a license amendment request to revise its PINGP TS to include the above EDG testing requirements.

SR 3.8.1.9 requires verification that every 24 months each EDG operates for ≥ 24 hours. Included in this 24 run, the Unit 1 EDG needs to run for ≥2 hours at a load ≥ 2832 kW and ≤ 3000 kW and Unit 2 EDGs at a load ≥5562 kW and ≤5940 kW. For the remaining 22 hours of the test the loading requirement is ≥2475 kW for the Unit 1 EDGs, and the loading requirement is ≥4860 kW for the Unit 2 EDGs. However, the NRC staff observed that these tests are performed at a unity power factor (no power factor is specified in the TS) rather than the design load power factor. The power factor requirement ensures that the generator and excitation system is appropriately loaded during the test since, for a given real power, the current loading on both will increase as the power factor decreases. In order to fully test the capabilities of the EDGs, they should be tested as close as possible to the actual conditions they will be exposed to under emergency operation. Therefore, testing at the appropriate power factor ensures that actual conditions are met. An EDG

operating at a .85 power factor will carry approximately 18 percent more armature (output) current than a machine operating at unity (1.0) power factor. This additional current will result in additional generator heating thereby providing additional stress on the generator and regulator components. Testing at a design power factor ensures that failures or incipient failures related to power factor will not long go undetected. Since surveillance testing is not conducted at the design load power factor, the effect that the load power factor has on the capacity requirements for these EDGs is not considered at PINGP. Therefore, the 24-month testing should be performed at the design load power factor in order to provide additional assurance of health and safety.

The NRC staff also concludes that the following additional compensatory measures would provide additional assurance of health and safety as regulatory commitments for limiting plant vulnerabilities during the extended DG outages. In a letter dated May 10, 2007, the licensee made the following commitments:

- A Configuration Risk Management Program is in place to assess the overall impact of maintenance on plant risk before entering the LCO action statement for planned activities.

- The Cross-tie will be verified to be available before entering the extended outage.

In view of the above, the NRC staff concludes that EDGs D1, D2, D5 and D6 have sufficient capacity to supply LOOP safe shutdown loads of its own unit and LOOP safe shutdown loads of the other unit inoperable EDG bus. Although the transient effects of manually connecting Unit 2 SBO loads onto the Unit 1 EDGs subsequent to a LOOP event on Unit 1 was not performed, the licensee demonstrated that for the worst case event the transient effects on the Unit 1 EDGs would be bounded by the Unit 1 large break LOCA analysis. Therefore, these EDGs are qualified as excess capacity AAC sources for the purpose of granting EDG CT extension from the current 7 days to 14 days provided the licensee revised PINGP TS to include specifications corresponding to NUREG-1431, 3.8.1.3 and 3.8.1.14.

The NRC staff finds the licensee's request to extend the CT specified in TS 3.8.1 to restore an inoperable EDG to operable status from the current 7 days to 14 days to be acceptable. All the regulatory commitments for limiting plant vulnerabilities during the extended DG outages are listed in Section 5.0.

3.1.4 DETERMINISTIC CONCLUSION

Based on the considerations discussed above, the NRC staff concludes that the licensee's request to extend the CT specified in TS 3.8.1 to restore an inoperable EDG to operable status from the current 7 days to 14 days is justified for Unit 1 and Unit 2 EDGs from a deterministic stand point. Therefore, extending the CT for an inoperable DG from the current 7 days to 14 days is acceptable based on the following considerations:

(1) The extended CT will be typically used to perform infrequent (i.e., once every 24 months) diesel manufacturer's recommended inspections and preventive maintenance activities;

(2) The extended CT would reduce entries into the LCO and reduce the number of EDG starts for major EDG maintenance activities;

(3) The licensee will implement its configuration risk management program (CRMP) during the extended outage.

Further, the NRC staff believes that regulatory commitments to implement other restrictions and compensatory measures provide additional assurance with regard to the availability of the remaining sources of AC power during the extended CT. The NRC staff also concludes that the proposed changes have no affect on PINGP's conformance with the requirements of Draft GDC 24 and 39.

4.0 PROBABILISTIC RISK ASSESSMENT

The staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment, which are described in Sections 4 and 5 of the licensee's submittal (Reference 1), as supplemented (References 2, 3, and 4). The detailed evaluation described in this section supports the conclusion that: (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.

4.1 Detailed Description of the Proposed Change

The following provides a description of the proposed TS changes.

The proposed changes will allow a CT of 14 days for the EDG maintenance or testing activities. This will allow an additional 7 days beyond the current TS-allowed CT. A format error is also corrected by removal of the double lines at the top of the Actions Table on TS page 3.8.1-2.

The duration required to perform planned and corrective EDG maintenance has challenged the licensee ability to complete these activities within the current TS requirements. The longer CT will likely reduce the regulatory burden associated with EDG maintenance activities and avoid or minimize TS-required plant shutdown time due to EDG maintenance or testing.

The extended CT for EDGs improves effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities are associated with preparation and return to service activities, such as, tagging, fluid system drain-down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. The longer CT will allow more maintenance to be accomplished during a given on-line maintenance period and, therefore, would improve maintenance efficiency and may result in fewer maintenance periods. Thus, the total EDG unavailability may be reduced with this proposed change.

This change will allow some maintenance activities, which would otherwise require performance during a refueling outage, to be performed on-line. On-line preventive maintenance and

scheduled overhauls provide the flexibility to focus more quality resources on any required or elective diesel generator maintenance. For example, during refueling outages, resources are required to support many systems during online maintenance and plant resources can be more focused on the diesel generator overhaul.

Performance of more diesel generator maintenance online, will improve EDG availability during plant refueling outages. Performing more EDG overhaul activities online, should reduce the risk and synergistic effects on risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

4.2 Staff Review Methodology

As set forth in the Standard Review Plan (SRP), Chapter 16.1, "Risk-Informed Decision making: Technical Specifications," the staff reviewed the submittal against the five key principles of the staff's philosophy of risk-informed Decision making listed in RG 1.177, Section B.

4.3 Key Information Used in Staff Review

The key information used in the staff's review of the risk evaluation is contained in Exhibit A of the licensee's submittal (Reference 1), as supplemented by the licensee in response to staff questions (References 2, 3 and 4). In addition, the staff consulted the staff evaluation reports on the individual plant examinations (IPEs) and individual plant examinations - external events (IPEEEs) submitted by the licensee (References 5 and 6).

4.4 Comparison Against Regulatory Criteria/Guidelines

The staff's comparison of the licensee's proposed license amendment for extending the CT of TS 3.8.1 required action B.4 from 7 days to 14 days against the five key principles of risk-informed decision making is presented in the following sections.

4.4.1 Traditional Engineering Evaluation

The traditional engineering evaluation consists of the first three key principles of the staff's philosophy of risk-informed decision making, which concern compliance with current regulations, evaluation of defense-in-depth, and evaluation of safety margins. The traditional Engineering evaluation is performed in Section 3.1, Deterministic Evaluation.

4.4.2 Risk Evaluation

The risk evaluation presented below addresses the last two key principles of the staff's philosophy of risk-informed decision making, those which concern changes in risk and performance measurement strategies. These key principles were evaluated by using the three-tiered approach described in Chapter 16.1 of the SRP and RG 1.177.

- Tier 1 - The first tier evaluates the licensee's PRA and the impact of the change on plant operational risk, as expressed by the change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF). The change in risk is compared against the acceptance guidelines presented in RG 1.174. The first tier also evaluates plant risk during the period when equipment is taken out of service (OOS) per the license amendment, as expressed by the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). The incremental risk is compared against the acceptance guidelines presented in RG 1.177.

- Tier 2 - The second tier addresses the need to preclude potentially high-risk plant configurations that could result if equipment, in addition to that associated with the proposed license amendment, is taken OOS simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The objective of this part of the review is to ensure that appropriate restrictions on dominant risk-significant plant configurations associated with the CT extension are in place.

- Tier 3 - The third tier addresses the licensee's overall CRMP to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and taking appropriate compensatory measures to avoid such configurations. The CRMP is to ensure that equipment removed from service prior to or during the proposed extended CT period will be appropriately assessed from a risk perspective.

4.4.2.1 Tier 1: PRA Capability and Insights

The staff review involved two aspects: (1) evaluation of the validity of the PRA and its application to the proposed CT extension; and (2) evaluation of the PRA results and insights stemming from its application.

4.4.2.1.1 Evaluation of PRA Validity

To determine whether the PRA used in support of the proposed CT extension is of sufficient quality, scope, and level of detail, the staff evaluated the relevant information provided by the licensee in their submittal and supplements. The staff's review of the licensee's submittal focused on the validity of the licensee's PRA model to analyze the risks stemming from the proposed CT extension and did not involve an in-depth review of the licensee's PRA. The following information from the licensee’s submittal provided the basis for this portion of the staff’s review.

The PINGP PRA models address internal events at full power and are updates of the original IPE submitted in response to Generic Letter 88-20. The licensee provided a summary of the revisions since the submittal of the PRA to satisfy the IPE requirements. The level 1 and level 2 PRA model are currently on Revision 2.1. In addition to incorporating recent advances in PRA technology across all elements of the PRA, a special effort was made to ensure that elements of the PRA are

adequate to evaluate the risk impacts of the increased CT for the EDGs. These elements include the proper characterization of initiating events involving LOOP, treatment of time dependent offsite power recovery, treatment of operator actions to implement bus ties and other emergency operating procedures actions, and data analysis of key parameters such as EDG failure rates, maintenance unavailabilities, and common cause failure probabilities.

LERF was estimated using the methodologies in NUREG/CR-6595, January 1999, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This approach to LERF evaluation, while somewhat simplified, supports realistic quantification of systematic contributions to containment isolation failures, bypass sequences that are derived from the Level 1 (core damage) model, and conservative evaluation of severe accident challenges which are less important for pressurized-water reactors with large, dry containments.

Peer review certification of the PINGP PRA model using the Westinghouse Owners Group (WOG) Peer Review Certification Guidelines was performed during the week of September 25, 2000. A team of independent PRA experts from nuclear utility groups and PRA consulting organizations carried out this Peer Review Certification. This intensive peer review involved about two person-months of engineering effort by the review team and provided a comprehensive assessment of the strengths and limitations of each element of the PRA model. The findings and observations from this assessment that were considered important by the review team and that are needed to evaluate the proposed CT extension have been dispositioned. The Peer Review Certification of the PINGP PRA model performed by WOG resulted in five Findings and Observations (F&Os) with the significance level of "A" and 32 F&Os with a significance level of "B." This peer review resulted in a number of enhancements to the PRA model prior to its use to support the proposed CT extension.

The certification team determined that, given acceptable resolution of the peer review comments, the quality of all elements of the PINGP PRA model is sufficient to support "risk significant evaluations with deterministic input." As a result of the effort to incorporate the latest industry insights into the PRA model upgrades and certification peer reviews, NMC has concluded that the results of the risk evaluation are technically sound and consistent with the expectations for PRA quality set forth in RG 1.174 and RG 1.177.

The staff reviewed NMC's resolution of the F&O's for the peer review of the PRA model. F&O's related to the EDG CT extension have been dispositioned by the licensee. The staff noted during the review of the model update summaries that the PINGP Unit 2 model was developed from the Unit 1 model after the peer certification. In response to an NRC staff question, NMC provided the following discussion of Unit 2 PRA model validity:

Shared plant systems, e.g., 4kv AV power, cooling water, auxiliary feedwater system cross-ties, and instrument air, were in the Unit 1 PRA model at the time of the peer review. The Unit 2 specific portions of the PINGP PRA model are essentially a mirror image of the corresponding Unit 1 model portions (which were peer reviewed). The only differences between the Unit 1 and Unit 2 symmetric system fault trees are the basic event names, descriptions (which reflect Unit 2 equipment), and support system linkages such as power supplies that are specific to Unit 2 equipment.
The licensee also stated that the methodology and assumptions used in the Unit 1 portion of the model, not driven by physical differences between the units, are applied in the same way in the Unit

2 portion of the model. In addition, the updates that have been performed to address peer review issues have been applied to modeling for both units. Additionally, upon expansion to include Unit 2 CDF and LERF risk metric quantification, the licensee added that the model was subjected to a series of reviews intended to identify incorrect modeling assumptions and errors in modeling.

Based upon the above, the staff finds that the PRA used in support of the proposed EDG CT extension is of sufficient quality, scope, and level of detail to analyze the risks stemming from the proposed CT extension, consistent with the guidance in RG 1.174 (section 2.2.3), SRP 19.0 (Sections III.2.2.2, III.2.2.3, III.2.2.4 and Appendix A) and SRP 19.1.

4.4.2.1.2 Evaluation of PRA Results and Insights

The licensee provided a risk assessment of the proposed license amendment for extending the EDG CT of TS 3.8.1 Required Action B.4 from 7 days to 14 days.

To determine the effect of the proposed 14-day CT for restoration of an inoperable EDG, the guidance in RG 1.174 and 1.177 was used.

The current maintenance unavailabilities in the PINGP PRA models are based on actual plant data and reflect the on-line maintenance that is currently performed on each EDG. It should be noted that, although the CT may be relaxed, PINGP does not intend to relax the EDG performance criteria established in response to 10 CFR 50.63 (station blackout rule) and 10 CFR 50.65 (the maintenance rule).

It is assumed for the purposes of this analysis that the EDG preventive maintenance (PM) term will increase as a result of performing the major overhaul on-line. The PM term in the PRA model is assumed to increase to account for a 14-day major overhaul once per refueling cycle for each EDG. The refueling cycle length is assumed to be 18 months with an assumed total planned and unplanned outage duration of 30 days, which yields a cycle length of 518 days. This corresponds to about 10 additional days of PM per EDG per year, on average. The PM increases were made simultaneously to all EDGs. The ΔCDF and ΔLERF results for increased preventive maintenance can be found in Table 1.

Table 1
ΔCDF and ΔLERF Results for Increased PM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 Criteria
Baseline CDF	1.5E-05	1.6E-05	N/A
Baseline LERF	5.7E-07	5.7E-07	N/A
Delta CDF	3.8E-07	5.1E-07	< 1E-6
Delta LERF	< 5E-10	< 5E-10	< 1E-7

The above results are considered very small using the RG 1.174 acceptance guidelines.

As a sensitivity study, it is assumed that the corrective maintenance (CM) term may increase as a result of extended outage time available for emergent work. The existing CM term was scaled by the ratio of the proposed and current CT or 14/7. The PM and CM increases were made simultaneously to all EDGs. The ΔCDF and ΔLERF results for increased preventive and corrective maintenance can be found in the Table 2 below.

Table 2
Sensitivity Study: PM and CM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 Criteria
Baseline CDF	1.5E-05	1.6E-05	NA
Baseline LERF	5.7E-07	5.7E-07	NA
Delta CDF	5.0E-07	6.7E-07	< 1E-6
Delta LERF	< 5E-10	< 5E-10	< 1E-7

The licensee calculated the ICCDP and ICLERP for the requested EDG CT extension. The results are shown in Table 3. The ICCDP and ICLERP are computed for each unit with the target EDG inoperable and the remaining EDGs in service, with no other PM and CM terms changed.

Table 3
ICCDP and ICLERP for EDG
When EDG is Inoperable for Preventative Maintenance

Unit	EDG Inoperable	ICCDP	ICLERP
1	D1	1.5E-7	< 5E-10
	D2	1.8E-07	< 5E-10
	D5	2.0E-07	< 5E-10
	D6	2.2E-07	< 5E-10
2	D1	2.0E-07	< 5E-10
	D2	1.3E-07	< 5E-10
	D5	3.0E-07	< 5E-10
	D6	2.5E-07	< 5E-10

The calculated ICCDP and ICLERP are less than the RG 1.177 acceptance guidelines of 5.0E-07 for ICCDP and 5.0E-08 for ICLERP. The results in Table 3 show that in all cases, the calculated ICCDP when an EDG is inoperable for PM are less than the 5E-07 criteria listed in RG 1.177.

The licensee provided some insights into the ICCDP values provided in Table 3:

- Each 4 kV safeguards bus on each unit is supported with its own dedicated EDG with
- cross-tie capability between the same train across units;
- There is limited common-cause potential between the Unit 1 and Unit 2 EDG as they are of different design and manufacture; and
- Cross-tie capability across Unit 1 and Unit 2 4kV buses between the same train is easily accomplished from the control room.

The licensee provided an explanation of the asymmetry in the risk importance among the EDGs. D1 EDG has a higher ICCDP for Unit 2 than for its associated Unit 1. Because D1 EDG does not provide power to an auxiliary feedwater (AFW) pump for Unit 1, it is more important to Unit 2, as it supplies power to an air compressor that can supply air for bleed and feed cooling for Unit 2 following a dual unit LOOP and failure of D5 EDG. D5 EDG provides power to an air compressor, but also to the Unit 2 motor-driven AFW pump. Failure of D5 EDG following a dual unit LOOP increases the importance of D1 EDG.

In response to an NRC question, the licensee provided the detailed human reliability analysis for the manual action to cross-tie the 4kV buses between units. This action is proceduralized and performed entirely from the control room. The licensee has validated on the plant-specific simulator that this action can be performed within 10 minutes of an SBO. Actual bus cross-tie is demonstrated every refueling outage.

The licensee performed a sensitivity analysis at the staff's request to explore how the risk metrics would change if the human error probability associated with the manual actions to cross tie the 4kv buses were increased by an order of magnitude.

The sensitivity analysis showed that, even increasing the 4kV bus cross-tie human error probability by a factor of 10, the CDF, LERF, ΔCDF and ΔLERF are within the acceptance guidelines of RG 1.174 for being "very small." All but two plant configurations are within the RG 1.177 acceptance guidelines for ICCDP and ICLERP. The Unit 2 ICCDP's for EDG D3 and D4 OOS are slightly above the RG 1.177 acceptance guidelines. The staff concludes that the risk metrics would still meet the applicable acceptance guidelines even given some uncertainty in the human error probability assigned to the 4kV bus cross-tie action.

In response to a staff question, the licensee increased the loop frequency to the industry mean (68 percent increase) and performed a sensitivity study. The sensitivity study showed that all but one diesel (EDG D5) was below the RG 1.174 acceptance guidelines. The licensee performed a sensitivity study on the proposed CT extension with respect to core damage contributions. The sensitivity study did not identify new outliers or major changes in the risk profile.

The staff concludes that the risk impact of the extension of the AOT of the EDG lies in Region III of Figures 3 and 4 contained in RG 1.174. Therefore, in accordance with the RG 1.174 risk acceptance guidelines, the licensee's proposed license amendment results in an acceptable increase in risk that is very small and consistent with the NRC's Safety Goal Policy Statement.

The staff also concludes that the calculated ICCDP and ICLERP when an EDG is unavailable for preventive maintenance during the extended AOT are less than the RG 1.177 acceptance guidelines of 5.0E-07 for ICCDP and 5.0E-08 for ICLERP for the full 14-day CT. Therefore, the staff finds that the licensee's first tier risk evaluation, is acceptable.

4.4.2.1.3 External Events

4.4.2.1.3.1 Internal Fire

The licensee provided a brief explanation of the fire modeling performed at PINGP in the LAR. The LAR states that the fire modeling performed for the IPEEE Fire PRA was limited to those areas that were of highest risk significance to Unit 1, which included a number of common areas (including control and cable spreading rooms, the AFW instrument air compressor rooms, and the lower level of the screenhouse). Only one fire area receiving detailed fire modeling can be considered to be a "Unit 1 only" fire area (Fire Area 58, basement of the auxiliary building on the Unit 1 side). The modeling that was performed in each case was done to support an analysis of Unit 1 risk. Nevertheless, for the Unit 1 and common areas that received detailed fire modeling for the IPEEE analysis, the Unit 2 counterpart fire areas are nearly symmetrical in terms of fire area geometry, equipment contained within the fire areas, equipment locations within the compartments and proximity to potential ignition sources, and cable routings, such that similar results could be expected from a full Unit 2 Fire PRA model.

The licensee states that the extension of the TS CT for the EDGs does not have any significant impact on the likelihood of occurrence of fires at PINGP, or on their location within the plant. Also, the EDG's safety function is to start and run to provide onsite power to safeguards equipment in the event that offsite power is lost. The licensee stated that the likelihood of a fire resulting in a complete SBO is low at PINGP. The IPEEE analysis identified only one fire (a large unsuppressed fire within an electrical panel in the control room) in which loss of offsite power sources to both Unit 1 safeguards 4kV buses was credible and only three additional fire areas in which LOOP offsite sources to both Unit 2 4kV buses was credible. In all other areas, a complete LOOP power requires additional equipment failures. Therefore, the licensee limited the analysis scope for increased fire risk due to the proposed EDG CT extension to an assessment of the increased risk of SBO and loss of individual safeguards 4 kV AC bus events.

The licensee analyzed the change in fire risk for SBO and safeguards bus failures assuming that the EDG unavailability was increased by a factor of two as a result of the increased EDG CT. The calculated risk increase was on the order of 1E-6 per year. The licensee stated that the results were conservative for several reasons, including:

- Spurious actuation of equipment due to fire was assigned a probability of 1.0
- It took no credit for suppression of fires in the bus rooms.
- IPEEE vintage fire modeling was used; it is expected that more detailed fire modeling would result in lower risk increases.

The licensee concluded that the increase in risk of an SBO event or even loss of an individual safeguards bus, due to the proposed EDG CT extension is extremely low.

The staff finds that, based on the conservative fire risk assessment performed by the licensee, the fire risk of extending the EDG CT is small and consistent with RG 1.174 guidance.

4.4.2.1.3.2 Seismic and Other External Events

The licensee stated that the evaluation of seismic events performed as part of the IPEEE used the Electric Power Research Institute Seismic Margins Assessment methodology. Both trains of EDG for each unit were included in the list of components analyzed for safe shutdown following an earthquake. The EDG buildings were also analyzed. No significant seismic concerns were identified and it was concluded that the plant possesses significant seismic margin.

Evaluation of high winds, external floods, and other external events in the PINGP IPEEE per NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," published in June 1991, revealed no potential vulnerabilities. The proposed changes to the EDG CT have negligible effect on the risk profile at PINGP from other external events.

Therefore, the staff finds that the licensee's Fire and External Events evaluation is acceptable.

4.4.2.1.3.3 Shutdown Risk

The licensee stated that extending the EDG CT to 14 days will allow more on-line special overhauls which will improve EDG availability during plant refueling outages and should reduce the risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

Therefore, the staff finds that the licensee's shutdown risk evaluation is acceptable.

4.4.2.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

The second tier evaluates the capability of the licensee to recognize and avoid risk-significant plant configurations that could result if equipment, in addition to that associated with the proposed license amendment, is taken OOS simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved.

RG 1.177, Section 2.3, describes one possible method for performing a Tier 2 evaluation for risk-informed TS CT Extension LARs. This method involves evaluation of combinations of equipment OOS (including the specific equipment for which the LAR is requesting the CT extension) against the Tier 1 ICCDP acceptance guideline (ICCDP < 5E-7). For combinations of equipment unavailability (configurations) found to exceed this risk threshold, a discussion of the controls in place to prevent these configurations from occurring, or the compensatory measures that will be put in place to limit the risk increase, during the CT extension period is required.

In response to an NRC staff question, the licensee evaluated potential risk-significant configurations that may be encountered during the extended CT period should other risk-significant equipment experience unplanned unavailability (Reference 2). The licensee stated that unavailability of diesel generators only impacts the mitigation of the LOOP power initiating event, by performing the function to restore power to safeguards equipment. Therefore, equipment unavailability configurations providing the highest increase in risk when a diesel generator is unavailable are those that provide or support a redundant and/or diverse means of

performing this function. The licensee identified for each EDG OOS, which equipment would result in an ICCDP above the RG 1.177 acceptance guidelines. The licensee stated the TS restrictions were sufficient to limit time in many of these plant configurations and made commitments (Section 4.0) to control plant configurations where TS restrictions were deemed insufficient.

In addition, NMC has implemented unavailability monitoring performance criteria for key risk-significant equipment at PINGP that is shared between the units during shutdown conditions, including the safeguards 4 kV buses under the plant Maintenance Rule program. These criteria include, as a significant part of their basis, the risk-significance of the unavailability of the bus cross-tie capability (to the at-power unit) while the bus is unavailable for maintenance.

The information provided by the licensee indicates the capability of the licensee to recognize and avoid risk-significant plant configurations that could result if equipment, in addition to that associated with the proposed license amendment, is taken OOS simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The existing TS and the commitments made by the licensee provide effective control over this equipment. Therefore, the staff finds that the licensee's second tier risk evaluation, as described in Chapter 16.1 of the SRP and RG 1.177, is acceptable.

4.4.2.3 Tier 3: Risk-Informed Configuration Risk Management

The third tier assesses the licensee's program to ensure that the risk impact of OOS equipment is appropriately evaluated prior to performing any maintenance activity. The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under the second tier that could ever be encountered. The licensee's submittal discusses implementation of the third tier.

NMC has developed a CRMP for PINGP, governed by a plant procedure that ensures that the risk impact of equipment OOS is appropriately evaluated prior to performing any maintenance activity. The CRMP is used to satisfy Maintenance rule 10 CFR 50.65 (a)(4) requirement. This program requires an integrated view (i.e., both deterministic and probabilistic) to identify risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities like testing, or load dispatching and weather conditions.

NMC currently has the capability at PINGP to perform a configuration-dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure, malfunction, or emergent condition produces a plant configuration that has not previously been assessed. For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed prior to scheduled work. The assessment includes the following considerations:

- Maintenance activities that affect redundant and diverse systems, structures, and components (SSCs) that provide backup for the same function are minimized.

- Maintenance is not scheduled that is highly likely to exceed a TS or Technical Requirements Manual CT requiring a plant shutdown. For activities that are expected to exceed 50 percent of a TS CT, a voluntary LCO plan is developed to minimize SSC unavailability, maximize SSC reliability, and ensure contingency and compensatory actions are in place.

- For Maintenance Rule risk-significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the current Level 1 PRA model. The results of the risk assessment are classified by a color code based on the increased risk of the activity. Increasing levels of risk require increasing management approval.

- Plant operation's management during non-business hours reviews emergent work to ensure that it does not invalidate risk analyses made during the work management process, and if it does, they are capable of updating the risk analyses.

- If the risk of losing offsite power increases as a result of severe weather or as a result of unavailability or degradation of an offsite source, the CRMP is able to reflect this in the risk analysis.

In response to a staff question, the licensee confirmed that the CRMP in use at PINGP does not credit recovery of the OOS equipment.

Based on the licensee’s description of their CRMP, the staff finds that the licensee’s third tier risk evaluation is acceptable.

4.5 Staff Findings

In summary, the staff finds that the licensee's proposed change to extend the CT associated with TS 3.8.1 Required Action B.4 from 7 days to 14 days is acceptable because the five key principles of risk-informed decision-making identified in RG 1.174 and RG 1.177 have been satisfied. Thus, the staff has concluded that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in this manner; (2) such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 REGULATORY COMMITMENTS

The licensee made the following commitments in References 1 and 2, to be put into effect upon implementation of the requested license amendment.

Procedures shall be established to assure that the following provisions are invoked when an EDG is inoperable for an extended CT in TS 3.8.1 Condition B.

1. The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended EDG CT for elective maintenance. NMC will develop a procedure to determine acceptable grid conditions for entering an extended EDG CT to perform elective

maintenance. An extended EDG CT will not be entered to perform elective maintenance when grid stress conditions are high such as during extreme summer - temperatures or high demand.

2. No elective maintenance will be scheduled in the switchyard that would challenge offsite power availability and no elective maintenance will be scheduled on the main, auxiliary, or startup transformers associated with the unit during the proposed extended EDG CT.

3. The system dispatcher will be contacted once per day to ensure no significant grid perturbations are expected during the extended EDG CT. The system dispatcher will be informed of the EDG status, the power needs of the facility and requested to inform PINGP if conditions change such that unacceptable voltage would occur following a unit trip.

4. The LCO statement requirements of TS 3.8.1 and TS 3.8.9, for safeguards ac buses will be met on the opposite unit (regardless of mode) during the extended EDG CT (required emergent corrective maintenance or TS required surveillance testing on EDGs, offsite paths or safeguards ac buses may be performed).

5. The turbine-driven AFW pump on the associated unit will not be removed from service for planned maintenance activities during the extended EDG CT.

6. Assure operating crews are briefed on the EDG work plan and procedural actions regarding:

   - o LOOP and SBO
   - o 4 kV safeguards bus cross-tie
   - o Reactor Coolant System bleed and feed

7. Weather conditions will be evaluated prior to entering the extended EDG CT for elective maintenance. An extended EDG CT will not be entered for elective maintenance purposes if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings).

8. 12 and 22 cooling water (CL) pumps will be operable and 121 CL pump will be available and aligned to the operable Unit 2 EDG when a Unit 2 EDG is in an extended CT, except required emergent corrective maintenance or TS-required surveillance testing on these CL pumps or Unit 2 EDGs may be performed if required.

9. Assess the overall impact of maintenance on plant risk using a Configuration Risk Management Program before entering TS 3.8.1 Condition B for planned EDG maintenance activities.

10. Verify that the safeguards bus cross-tie between the Unit 1 and Unit 2 safeguards buses are available before entering the TS 3.8.1 Condition B for extended EDG maintenance activities.

11. NMC shall submit a License Amendment Request which proposes changes to the Technical Specifications in Appendix A, similar to current plant procedural practices, which will require the Unit 1 monthly Emergency Diesel Generators load test (SR 3.8.1.3) to be performed at or above 90% of the diesel generator's continuous power rating.

12. NMC shall submit a License Amendment Request which proposes changes to the

Technical Specifications in Appendix A which will require the 24-hour Emergency Diesel Generators load test (SR 3.8.1.9) to be performed at or below a specified power factor. These changes shall be consistent with the guidance in NUREG-1431, “Improved Technical Specifications, Westinghouse Plants”, Revision 3.1, SR 3.8.1.14.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitment(s) are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (i.e., items requiring prior NRC approval of subsequent changes).

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Minnesota State official was notified of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendment changes the requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (71 FR 151). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (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.

Principal Contributor: Ogbana Hopkins, Stephen Laur, Om Chopra

Date: May 30, 2007