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May 12, 2003

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
License Amendment Request: Extension of Diesel Generator Required Action Completion Time

Pursuant to 10 CFR 50.90, Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP) hereby requests an amendment to Renewed Operating License Nos. DPR-53 and DPR-69 to incorporate the changes described below into the Technical Specifications for Calvert Cliffs Unit Nos. 1 and 2. Specifically, CCNPP proposes to amend Technical Specification 3.8.1, "AC Sources-Operating" to extend several Required Action Completion Times for inoperable diesel generators (DGs). The Bases for Technical Specification 3.8.1 will be modified to address the proposed changes.

BACKGROUND

Calvert Cliffs is a two unit site. A total of four DGs, two dedicated to each unit, are provided to supply power to the engineered safety features loads. Three of these DGs are Fairbanks Morse diesels with generators, each with a continuous rating of 3000 kW. The fourth is a Societe Alsacienne De Constructions Mecaniques De Mulhouse (SACM) DG with a continuous rating of 5400 kW. Although the Fairbanks Morse and SACM DGs have different continuous ratings, either of the two DGs dedicated to a unit is capable of supplying all of the engineered safety features loads for the associated bus. In addition, an augmented-quality Station Blackout SACM DG (designated 0C DG) with a continuous rating of 5400 kW is installed. This DG can be aligned to any of the four 4160 Volt emergency buses to support station blackout loads or engineered safety features loads, if necessary. The site electrical distribution system has shared functions between the Units. Therefore, the dedicated DGs not only provide support to their specified Unit, but also to the opposite Unit. This dependency is reflected in the Technical Specifications.

DESCRIPTION

There are three Conditions that are proposed to have extended Completion Times. Each of the three proposed changes also have associated changes as shown on the Table below. A more complete, in depth explanation of these proposed changes is contained in Attachment (1). Attachment (3) contains the

A001

marked up Technical Specification pages. Attachment (4) contains the final Technical Specification pages.

Condition		Current Required Action	Current Completion Time	Proposed Required Action and/or Completion Times
One LCO 3.8.1.b DG inoperable		B.4	72 hours	14 days
	Associated Changes	A.3	6 days	17 days
		New B.1	N/A	Verify opposite unit DGs operable and 0C DG available
		New C.1.1 and C.1.2	N/A	If new B.1 is not met, meet B.1 or restore inoperable DG within 72 hours
One LCO 3.8.1.c DG inoperable		D.4	72 hours	21 days
	Associated Changes	New E.1	N/A	Verify other DGs operable and 0C DG available
		New F.1.1 and F.1.2	N/A	If new E.1 is not met, meet E.1 or restore inoperable DG within 72 hours
Two DGs inoperable		G.1	2 hours	12 hours
	Associated Changes	New I.1	N/A	Verify 0C DG available and one other DG operable
		New J.1.1 and J.1.2	N/A	If I.1 is not met, meet I.1 or restore one DG within 2 hours

Currently, the Required Action Completion Time for a single inoperable DG is 72 hours regardless of the status of the 0C DG or the other safety-related DGs. The first proposed change will increase the Required Action Completion Time for a single inoperable safety-related DG to 14 days, provided that the 0C DG is available and the other three safety-related DGs are operable.

The second proposed Technical Specification change involves the Required Action Completion Time for declaring the Control Room Emergency Ventilation System (CREVS), Control Room Emergency Temperature System, and H_2 Analyzer trains inoperable when the safety-related back-up power supply (DG) is inoperable. The proposed change extends the current 72 hours to 21 days when a single DG is inoperable (i.e., 0C DG is available and three other safety-related DGs are operable) before the CREVS, Control Room Emergency Temperature System, and H_2 Analyzer trains are declared inoperable.

Currently, when both DGs dedicated to redundant safety-related equipment are inoperable, the Required Action Completion Time is 2 hours. The third proposed change increases this Required Action Completion Time to 12 hours provided the 0C DG is available and one other safety-related DG is operable.

In addition to the above changes, an administrative proposed change will also make a correction to the Completion Time for what is currently Required Action D.1 so that it correctly reads "once per 8 hours thereafter" instead of "one per 8 hours thereafter." The final Technical Specification 3.8.1 Required Actions and pages will be renumbered to accommodate the proposed changes.

These proposed changes are supported by a probabilistic risk evaluation and deterministic discussion meeting the criteria of Regulatory Guide 1.174, An Approach for Using Probabilistic Risk Assessment in Risk Informed Decisions on Plant Specific Changes to the Licensing Basis.

These proposed Technical Specification changes result in a net reduction in risk and fully meet the requirements of Regulatory Guide 1.174. The complete risk evaluation is provided in Attachment (1).

ASSESSMENT

We have evaluated the significant hazards considerations associated with this proposed amendment, as required by 10 CFR 50.92, and have determined that there are none (See Attachment 2 for a complete discussion). We have also determined that operation with the proposed amendments will not result in any significant change in the types or significant increases in the amounts of any effluents that may be released offsite, and no significant increases in individual or cumulative occupational radiation exposure. Therefore, the proposed amendments are eligible for categorical exclusion as set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact assessment is needed in connection with the approval of the proposed amendments.

SAFETY COMMITTEE REVIEW

The Plant Operations and Safety Review Committee and the Offsite Safety Review Committee have reviewed these proposed amendments and concur that operation with the proposed amendments will not result in an undue risk to the health and safety of the public.

SCHEDULE

During the Unit 1 2004 Refueling Outage, the 5-year overhaul is scheduled for 1A DG. It is expected that this overhaul will result in 1A DG being inoperable for greater than 10 days. In accordance with the current Technical Specifications, this will require a shutdown on Unit 2 since CREVS will be declared inoperable with a single DG inoperable for greater than three days. The Unit 1 2004 Refueling Outage is currently scheduled for April 2004. Therefore, we request approval of this proposed amendment as soon as possible or by February 15, 2004 to allow for the necessary outage planning. Please note, additional licensing actions to request a one time extension for the CREVS Required Action Completion Time will be considered if approval of this proposed amendment is not received in time to allow for outage planning.

PRECEDENT

- Millstone Nuclear Power Station, Unit No. 2 – Amendment No. 261, dated January 4, 2002
- Byron Station Unit Nos. 1 and 2 – Amendment No. 114, dated September 1. 2000
- Braidwood Station Unit Nos. 1 and 2 – Amendment No. 108, dated September 1, 2000
- Perry Nuclear Plant – Amendment No. 99, dated February 24, 1999

Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

Peter E. Katz

STATE OF MARYLAND :
: **TO WIT:**
COUNTY OF CALVERT :

I, Peter E. Katz, being duly sworn, state that I am Vice President - Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP), and that I am duly authorized to execute and file this License Amendment Request on behalf of CCNPP. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other CCNPP employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Peter E. Katz

Subscribed and sworn before me, a Notary Public in and for the State of Maryland and County of St. Mary's, this 12th day of May, 2003.

WITNESS my Hand and Notarial Seal: Janet L. Scally
Notary Public

My Commission Expires: March 25 2007
Date

PEK/DJM/bjd

Attachments: (1) Diesel Generator Required Action Completion Time Risk Analysis
(2) Determination of Significant Hazards
(3) Marked Up Technical Specification Pages
(4) Final Technical Specification Pages

cc: J. Petro, Esquire
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S. J. Loeper
T. S. O'Meara

File # 09.04
Electronic Docket

NRC 03-027

COMMITMENTS IDENTIFIED IN THIS CORRESPONDENCE:

- Modify 0C Diesel Generator ventilation system to improve its seismic response.

Responsible Person/Organization: RL Szoch

Due Date: 2/1/2004

CLB Revision Required? If yes,

Type:

Initiation Date:

CT No.:

Posting Requirements for Responses -- NOV/Order No

ATTACHMENT (1)

DIESEL GENERATOR REQUIRED ACTION COMPLETION TIME

RISK ANALYSIS

CALVERT CLIFFS NUCLEAR POWER PLANT

RAN: 02-020
REV: 2

RELIABILITY ENGINEERING
REU QUALITY RECORD

Diesel Generator Required Action Completion Time

Risk Analysis

ORIGINATOR:	Robert Cavedo Robert F. Cavedo	5/6/2003 DATE
REVIEWER:	John Koelbel John H. Koelbel	5/6/2003 DATE
APPROVAL:	B S O'Meara	5/6/03 DATE

LIST OF EFFECTIVE PAGES

Pages	Revision
Cover	2
i	2
ii	2
iii	2
iv	2
v	2
vi	2
vii	2
viii	2
1-54	2

LIST OF EFFECTIVE SOFTWARE FILES

Reliability Software Number: RSN-308
Folder: G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\

File Name	Software	Description
02-020-Rev2.doc	WORD 97	Analysis

Folder: G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files

DG-Tech-Spec-Chart4.xls	EXCEL 97	Tech Spec Basis Document Chart
EDG-Q-Changes.xls	EXCEL 97	Unavailability Split Fraction changes
MFF for All-with-High-EDG Failure Rates.xls	EXCEL 97	MFF with the DG Failure Rates Increased

Folder: G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\Unavailability Data from KLG

DG Unavail Hrs1.xls	EXCEL 97	Process Unavailable Hours from EDH

Folder: G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\Sensitivity Files

Data-EDG-Sen-Cases.xls	EXCEL 97	Processed Data for the DG Sensitivity Cases
EDG-Cases-2-plus-SR-OOS-mb.csv	Comma Delimited Files	DG Cases with 2 or more DGs OOS
EDG-OOS-All-Impacts-mb.csv	Comma Delimited Files	Evaluator Input Files for DG Cases
EDG-OOS-All-Impacts-Wind-Removed-mb.csv	Comma Delimited Files	Evaluator Output Files for DG Cases
EDG-Sen-Cases.xls	EXCEL 97	DG Sensitivty Case Results
EDG-Sen-Cases-mb.csv	Comma Delimited Files	Evaluator Input Files for DG Sensitivity Cases Part 1
EDG-Sen-Cases-RB.csv	Comma Delimited Files	Evaluator Output Files for DG Sensitivity Cases Part 1
EDG-Sen-Cases-Sorted.xls	EXCEL 97	DG Sensitivty Case Results
More-EDG-Sen-Cases-mb.csv	Comma Delimited Files	Evaluator Input Files for DG Sensitivity Cases Part 1
More-EDG-Sen-Cases-RB.csv	Comma Delimited Files	Evaluator Output Files for DG Sensitivity Cases Part 1
New-All-EDG-OOS-Results-DEEP Run.xls	EXCEL 97	Truncation Impact for DG OOS
Sen-Figures.xls	EXCEL 97	Sensitivity Figures

LIST OF EFFECTIVE SOFTWARE FILES (Continued)

Directory of G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\MFF Store\Normal

BIN1.MFF	Text	Seismic Bin1 RISKMAN MFF Base Case
BIN2.MFF	Text	Seismic Bin2 RISKMAN MFF Base Case
BIN3.MFF	Text	Seismic Bin3 RISKMAN MFF Base Case
F_AB_MFF.MFF	Text	Fire Aux Bldg RISKMAN MFF Base Case
F_CR_MFF.MFF	Text	Fire Cntrl RM and CSR RISKMAN MFF Base Case
F_IN_MFF.MFF	Text	Fire Intake RISKMAN MFF Base Case
F_TB_MFF.MFF	Text	Fire Turbine Bldg RISKMAN MFF Base Case
F_YD_MFF.MFF	Text	Fire Yard RISKMAN MFF Base Case
UP3INTA.MFF	Text	Internal Events and Wind RISKMAN MFF Base Case

Directory of G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\MFF Store\EDG Up Sensitivity

BIN1.MFF	Text	Seismic Bin1 RISKMAN MFF DG Failure Probabilities Increased
BIN2.MFF	Text	Seismic Bin2 RISKMAN MFF DG Failure Probabilities Increased
BIN3.MFF	Text	Seismic Bin3 RISKMAN MFF DG Failure Probabilities Increased
F_AB_MFF.MFF	Text	Fire Aux Bldg RISKMAN MFF DG Failure Probabilities Increased
F_CR_MFF.MFF	Text	Fire Cntrl RM and CSR RISKMAN MFF DG Failure Probabilities Increased
F_IN_MFF.MFF	Text	Fire Intake RISKMAN MFF DG Failure Probabilities Increased
F_TB_MFF.MFF	Text	Fire Turbine Bldg RISKMAN MFF DG Failure Probabilities Increased
F_YD_MFF.MFF	Text	Fire Yard RISKMAN MFF DG Failure Probabilities Increased
UP3INTA.MFF	Text	Internal Events and Wind RISKMAN MFF DG Failure Probabilities Increased

LIST OF EFFECTIVE SOFTWARE FILES (Continued)

Directory of G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\MFF Store\HA Up Sensitivity

BIN1.MFF	Text	Seismic Bin1 RISKMAN MFF HA Failure Probabilities Increased
BIN2.MFF	Text	Seismic Bin2 RISKMAN MFF HA Failure Probabilities Increased
BIN3.MFF	Text	Seismic Bin3 RISKMAN MFF HA Failure Probabilities Increased
F_AB_MFF.MFF	Text	Fire Aux Bldg RISKMAN MFF HA Failure Probabilities Increased
F_CR_MFF.MFF	Text	Fire Cntrl RM and CSR RISKMAN MFF HA Failure Probabilities Increased
F_IN_MFF.MFF	Text	Fire Intake RISKMAN MFF HA Failure Probabilities Increased
F_TB_MFF.MFF	Text	Fire Turbine Bldg RISKMAN MFF HA Failure Probabilities Increased
F_YD_MFF.MFF	Text	Fire Yard RISKMAN MFF HA Failure Probabilities Increased
UP3INTA.MFF	Text	Internal Events and Wind RISKMAN MFF HA Failure Probabilities Increased

Directory of G:\NED\REU\Controlled Documents\RANS\2002\02-020\REV02\Report Related Files\MFF Store\New EDG Qs Files

EDG Qs-Post-AOT-Unit-1.csv	Comma Delimited Files	Unit 1 DG Unavailability Changes Post AOT
EDG Qs-Post-AOT-Unit-2.csv	Comma Delimited Files	Unit 1 DG Unavailability Changes Post AOT
EDG-Up.csv	Comma Delimited Files	AOT Update File

REVISION HISTORY

Revision	Description
0	Initial issue.
1	As the 0C DG is not SR, all references to the 0C DG being operable are removed.
	All Files Unique to the DG Evaluation are explicitly listed in the report.
	Clarified the statement in Section 4.1 regarding the focus of maintenance resources.
	Clarified the estimated DG OOS times in Sections 4.4, 6.1.1.1 and Table 5.
	Clarified the benefit of the 0C DG ventilation system being seismically hardened in Section 5.2.
	Clarified the description of Assumption 7.
	Provided more detail in the sensitivity evaluation regarding the CDF changes associated with Unit 1 as compared to Unit 2.
	Made several editorial changes.
2	Removed sentence regarding cross-unit DG availability in Section 5.1. The cross-unit availability only increases for the 1A DG.
	Clarified the last paragraph in Section 6.1.1.1 regarding possible changes to the MR performance criteria.

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TABLES

FIGURES

1.0 Introduction

This document is a risk-informed analysis supporting proposed amendments to the technical specifications for the diesel generators.

1.1 Summary of Proposed Change

The proposed changes address a change to the diesel generator required action completion time (CT).

1.1.1 Diesel Generator Required Action Completion Time

The proposed amendments to Facility Operating Licenses DPR-53 for Calvert Cliffs Unit-1 and DPR-69 for Calvert Cliffs Unit-2 will revise the Technical Specifications:

- Currently, the required action completion time for the DGs is 72 hrs regardless of the status of the 0C DG or the other SR DGs. The change increases the required action completion time for a single inoperable DG to 14-days. The 14-day required action completion time is only allowed when the 0C DG is available and the other three SR DGs are operable. The 72 hr required action completion time (CT) for all other conditions remains the same.

- DGs 1A and 2B also act as the emergency power supply for the other Unit's Control Room Emergency Ventilation System (CREVS). The current Technical Specification describes this relationship in LCO 3.8.1.c. Currently, LCO 3.8.1.c (applies to DGs 1A and 2B) is effectively 10 days. The effective 10 day required action completion time for DGs 1A and 2B as the 3.8.1.c DGs is driven by the CREVS required action completion time (3 days for the DGs and 7 days for CREVS). This effective 10 day required action completion time applies regardless of the status of the 0C DG or the other SR DGs. This change increases the required action completion time for the 1A and 2B DGs when acting as the 3.8.1.c DG to effectively 28 days (21 days for the DG and 7 days for CREVS). The 21-day required action completion time for a DG inoperable to CREVS is only allowed when the 0C DG is available and the other three SR DGs are operable. The 72 hr required action completion time for a DG inoperable to CREVS for all other conditions remains the same.
  This DG required action completion time extension also impacts the maximum required action completion time for the Control Room Emergency Temperature System (CRETS) and H2 analyzer. The CREVS required action completion time is considered to bound the impact on the CRETS and the H2 analyzer.

- Currently, when both DGs dedicated to redundant SR equipment are inoperable (e.g. 1A and 1B, 2A and 2B, or 1A and 2B), the required action completion time is 2 hours. The change increases the required action completion time to 12 hours. The 12-hour required action completion time is only allowed when the 0C DG is available and two other SR DGs are operable.

The proposed changes result in a net reduction in risk and fully meet the requirements of Reg. Guide 1.174. The benefit of making the 0C DG more seismically robust and the improvement in maintenance effectiveness outweighs the adverse impact of the increased required action completion time duration. Improving 0C DG seismically strengthens the overall plant's ability to respond to seismic challenges. The gain in maintenance efficiency will result from the need for fewer required action completion time entries for routine maintenance and therefore less unavailability associated with preparation and return-to-service activities. These two factors counterbalance the increase in unavailability that results from on-line overhauls.

Table 1
Proposed Required Action Completion Time Durations

Diesel Unavailable	Unit-1 Required Action Completion Time	Unit-2 Required Action Completion Time
1 of 5 Diesels Unavailable (Notes 1 and 2)		
1A	14 days	21 days
1B	14 days	N/A (Note 3)
2A	N/A (Note 3)	14 days
2B	21 days	14 days

Note 1: The case for the 0C DG OOS is not presented because the 0C DG remains without a required action completion time

Note 2: When both 1E DGs on the same Unit are inoperable, the 0C DG is available, and the other two SR on the other Unit are operable, then the required action completion time increases from 2 hours to 12 hours. For all other combinations where two or more of the five site diesel generators are unavailable, the proposed technical specifications are identical to the current technical specifications.

Note 3: The current Unit 2 technical specifications do not restrict the amount of time the 1B DG can be inoperable. The current Unit 1 technical specifications do not restrict the amount of time the 2A DG can be inoperable. This will not change in the proposed technical specifications.

1.2 Analysis Approach

The analysis includes an integrated review and assessment of plant operations, deterministic design basis factors, and an evaluation of overall plant risk using probabilistic risk assessment (PRA) techniques. Deterministically, the proposed change is supported by the defense-in-depth basis that is incorporated into the plant design as well as in the approach to maintenance and operation. With respect to plant risk, the proposed change is supported by a plant-specific risk analysis performed in accordance with NRC guidance for making risk-informed decisions and risk-informed changes to the plant Technical Specifications.

2.0 BACKGROUND

The site has four safety-related diesel generators (DGs) and one Station Blackout (SBO) diesel generator. Two DGs are dedicated to Unit-1 and two are dedicated to Unit-2. The site electrical distribution system has shared functions between the units. Therefore, the dedicated DGs not only provide support to their specified unit, but also to the opposite unit. The SBO diesel generator can support a single 4kV safety-related bus on either unit.

2.1 Electrical Distribution System

The CCNPP switchyard is connected to the grid by three physically independent 500kV transmission lines. Load flow and stability studies indicate that the tripping of one or both fully loaded CCNPP generating units would not impair the ability of the system to supply plant service. These studies were made at the projected peak load conditions and also at minimum load conditions when the two Calvert Cliffs units were supplying the entire Baltimore system (Calvert Cliffs UFSAR, Rev. 31, Section 8.2).

Two physically independent circuits from the switchyard to the onsite electrical system are also provided from two 500kV/13.8kV plant service transformers that are fed from separate 500kV switchyard busses. When available, the Southern Maryland Electric Cooperative (SMECO) substation is capable of supplying the power required to maintain both units in a safe shutdown condition (UFSAR, Rev. 31, Section 8.2).

The two plant service transformers feed six 13.8kV/4.16kV service transformers, three of which are capable of supplying the total plant 4.16kV auxiliary load. Four engineered safety features (ESF) busses are supported by these transformers. These busses can be supplied from the DGs or from the SBO diesel generator (UFSAR, Rev, 31, Sections 8.1 and 8.2)

2.2 Safety-Related Diesel Generators (DGs)

Any combination of two of the safety related DGs (one from each unit) is capable of supplying sufficient power for the operation of necessary engineered safety features (ESF) loads during accident conditions on one unit and shutdown loads of the alternate unit concurrent with a loss of offsite power and for the safe and orderly shutdown of both units under loss of offsite power conditions. The diesel generators start automatically following a safety injection actuation signal (SIAS) or an undervoltage condition on the busses that supply vital loads and are ready to accept loads within ten seconds (UFSAR, Rev. 31, Section 8.1). Table 2 summarizes the DG configuration.

The SACM safety-related diesel generator (1A DG) is installed in a separate and independent Category I building. This diesel also includes redundant air receivers, redundant air compressors, and a dedicated fuel oil storage tank within its building (UFSAR, Rev. 31, Section 8.4).

Table 2
CCNPP Diesel Generators

DG	Make	Design	Rating (Continuous)	Cooling	Unit	4.16kV Bus
1A	SACM (Societe Alsacienne De Constructions Mecaniques De Mulhouse)	4.16kV, three-phase, 60 cycle tandem-engine	5400 kW	outdoor ambient air	1	11
1B	FM (Fairbanks Morse)	4.16kV, three phase, 60 cycle single engine	3000 kW	SRW Header 12	1	14
2A	FM (Fairbanks Morse)	4,16kV, three phase, 60 cycle single engine	3000 kW	SRW Header 21	2	21
2B	FM (Fairbanks Morse)	4.16kV, three phase, 60 cycle single engine	3000 kW	SRW Header 22	2	24
0C	SACM (Societe Alsacienne De Constructions Mecaniques De Mulhouse)	4.16kV, three-phase, 60 cycle tandem-engine	5400 kW	outdoor ambient air	Either	Manually Align

2.3 Augmented Quality Station Blackout (SBO) Diesel Generator (0C DG)

The SBO diesel generator, designated as 0C DG, is designed to provide a power source capable of starting and supplying the essential loads necessary to safely shutdown one unit and maintain it in a safe shutdown condition during a SBO event (UFSAR, Rev. 31, Section 8.4). 0C DG is capable of supplying the same emergency plant loads as the DGs. The SBO DG can be aligned to any of the four ESF busses (UFSAR, Rev. 31, Section 8.1).

The 0C DG is similar to the safety-related 1A DG. The 0C DG's supporting systems and associated switchgear are housed in the SBO Diesel Generator Building. The 0C DG configuration is summarized in Table 2.

The 0C DG is classified as augmented quality. 0C DG and 1A DG were purchased under one safety-related equipment specification. The non-SACM components (e.g. structures and piping) associated with the 0C DG are not qualified or certified to industry and regulatory requirements applicable to a Class 1E diesel generator (UFSAR, Rev. 31, Section 8.4).

The SBO Diesel Generator Building is designed to withstand likely weather-related loads as addressed in the local Standard Building Codes. It is not explicitly protected against the effects of tornadoes or hurricanes (UFSAR, Rev. 31, Section 8.4).

0C DG is electrically isolated from the ESF busses by two breakers (one Class 1E and one non-Class 1E) and a Class 1E disconnect switch. The design of power connections from the 0C DG allow for manual alignment to any one safety-related train in either unit via a Class 1E ESF bus. Manual switching capability is provided through Class 1E disconnect switches and Class 1E breakers (UFSAR, Rev. 31, Section 8.4).

The SBO diesel is started manually. The diesel is loaded onto a 4.16kV bus when it is determined that the DG dedicated to that bus is not available to supply the plant loads. For planned maintenance of a DG, the 0C DG is "pre-aligned" by closing the local disconnect switches to the 4.16kV bus affected by the DG maintenance.

2.4 Current Technical Specification

Technical Specification 3.8.1 contains the requirements for the safety-related diesel generators (DGs) for Modes 1 through 4. The TS requires the unit's 2 DGs and the other unit's DG that supplies power to Control Room Emergency Ventilation System (CREVS), Control Room Emergency Temperature System (CRETS) and H2 Analyzer to be operable. Currently, the required action completion time for one of the unit's safety-related DGs is 72 hours.

The current Technical Specification allows the other unit's DG that supplies emergency power to the CREVS, CRETS, and H2 Analyzer to be inoperable for 72 hours before these components are to be declared inoperable. An operating Unit currently has a 7-day LCO for an inoperable CREV train. This results in an effective 10 day required action completion time for a DG on the other Unit that supports CREVS (DG 1A or DG 2B).

This is illustrated in the following example with Unit-1 operating and Unit-2 shut down.
DG 2B is removed from service for maintenance. Since Unit-2 is shutdown, Unit-2 requires only one of its two dedicated DGs (in this case DG 2A). Unit 1 is operating and requires DGs 1A and 1B and also DG 2B because it is the emergency power supply for one of the sites two common CREV/CRETs trains. When the 2B DG is taken OOS for maintenance, Unit-1 enters a 72-hour LCO because this back-up power source to one of the two required CREV trains is OOS. At the end of the 72 hours, with the 2B DG remaining OOS, the affected CREV train is declared inoperable for Unit-1. Unit-1 then enters a seven-day CREV LCO because only one of the two required CREV trains is operable. Therefore, in this example with Unit-2 shut down and Unit-1 operating, the total effective required action completion time for DG 2B in support of Unit-1 is ten days (3 days for the DG plus 7 days for CREVS).

For the CRETS and H2 Analyzer, this results in a total required action completion time of 33 days (3 days for the DG plus 30 days for CRET and H2 Analyzer). If two DGs dedicated to redundant safety-related equipment are inoperable, the required action completion time is 2 hours.

2.5 Regulatory Guide 1.155 DG Reliability Program

CCNPP maintains a DG reliability program based on Regulatory Guide 1.155, "Station Blackout." The program monitors and evaluates DG performance and reliability consistent with guidance provided in NUMARC 87-00, "Guidelines and Technical Bases 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 corrective actions for individual DG failures, and monitors DG unavailability. Table 3 shows the status of the DG Reliability Program as of August 2002.

Table 3
NUMARC 87-00 DG Target Reliability Levels

	Failures in last 20 demands	Failures in last 50 demands	Failures in last 100 demands	Targets for 0.975 DG reliability (failures in last 20/50/100 demands)
Unit-1	0	1	1	3 / 4 / 5
Unit-2	0	0	0	3 / 4 / 5
SBO*	0	1	1	3 / 4 / 5

* 0C DG is the station blackout diesel generator and is not reportable under the diesel reliability program.

The DG reliability program will not be negatively impacted by the proposed amendment. However, there is a potential that, due to the improved maintenance effectiveness and flexibility that will result from implementation of this amendment, the DG performance may improve.

2.6 Maintenance Rule (MR) (10CFR 50.65)

CCNPP monitors the reliability and availability of the DGs and the SBO DG as risk significant functions within the scope of the Maintenance Rule. The following Maintenance Rule criteria is currently used:

Table 4
Current Maintenance Rule Performance Criteria

Diesel Generator	Availability Criteria (unavailable hours per 2 years)	Availability Performance (unavailable hours per 2 years as of 6/30/2002)	Reliability Criteria (Functional Failures per 2 years)	Reliability Performance (Functional Failures) as of 6/30/2002)
1A	<300	172	<2	1
1B	<200	100	<2	0
2A	<200	257	<2	0
2B	<200	104	<2	0
0C	<800	405	<2	0

All diesels with the exception of the 2A DG are in the 10 CFR 50.65 a(2) MR category. Maintenance personnel identified degradation of the 2A DG flex gear during a routine surveillance: Repair efforts resulted in the 2A DG exceeding the unavailability performance criteria.

The proposed change to the Maintenance Rule performance indicators is discussed later in this document.

3.0 Description of Proposed TS Changes

The following proposed changes apply to CCNPP Unit-1 and Unit-2.

- Currently, the Required Action Completion Time for the DGs is 72 hrs regardless of the status of the 0C DG or the other SR DGs. The change increases the required action completion time for a single inoperable DG to 14-days. The 14-day required action completion time is only allowed when the 0C DG is available and the other three SR DGs are operable. The 72 hr required action completion time for all other conditions remains the same.

- DGs 1A and 2B also act as the emergency power supply for the other Unit's Control Room Emergency Ventilation System (CREVS). The current Technical Specification describes this relationship in LCO 3.8.1.c. Currently, LCO 3.8.1.c (applies to DGs 1A and 2B) is effectively 10 days. The effective 10 day required action completion time for DGs 1A and 2B as the 3.8.1.c DGs is driven by the CREVS required action completion time (3 days for the DGs and 7 days for CREVS). This effective 10 day required action completion time applies regardless of the status of the 0C DG or the other SR DGs. This change increases the required action completion time for the 1A and 2B DGs when acting as the 3.8.1.c DG to effectively 28 days (21 days for the DG and 7 days for CREVS). The 21-day required action completion time for a DG inoperable to CREVS is only allowed when the 0C DG is available and the other three SR DGs are operable. The 72 hr required action completion time for a DG inoperable to CREVS for all other conditions remains the same.
  This DG required action completion time extension also impacts the maximum required action completion time for the Control Room Emergency Temperature System (CRETS) and H2 analyzer. The CREVS required action completion time is considered to bound the impact on the CRETS and the H2 analyzer.

- Currently, when both DGs dedicated to redundant SR equipment are inoperable (e.g. 1A and 1B, 2A and 2B, or 1A and 2B), the required action completion time is 2 hours. The change increases the required action completion time to 12 hours. The 12-hour required action completion time is only allowed when the 0C DG is available and two other SR DGs are operable.

4.0 Basis for Proposed TS Changes

The longer required action completion time will help to avert a potential unplanned shutdown by providing margin for the performance of corrective maintenance that may be needed to resolve DG deficiencies discovered during equipment surveillances or scheduled preventive maintenance activities. In addition, the proposed required action completion time of fourteen days for a single inoperable DG will allow CCNPP to perform preventive maintenance work on-line that currently can only be performed during shutdown.

Plant configuration changes for planned and unplanned maintenance of the DGs, as well as the maintenance of equipment having risk significance, will be managed pursuant to the procedures and programs implemented at CCNPP for compliance with 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (the Maintenance Rule). Pertinent details of the plant Maintenance Rule Program are discussed later in this document.

4.1 Improved Maintenance Effectiveness

A significant portion of on-line maintenance activities is 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. Longer required action completion time durations would allow more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency.

Also, by allowing on-line preventive maintenance and scheduled overhauls, the change provides the flexibility to focus more quality resources on any required or elected diesel generator maintenance. For example, during plant outages resources are required to support many systems. However, during online maintenance plant resources can be more focused on the diesel generators.

4.2 Reduction of Need to Request Regulatory Relief

Planned and corrective maintenance has challenged the site ability to complete diesel generator maintenance within the TS requirements. This proposed amendment averts unplanned plant shutdowns and minimizes the potential need for Notice of Enforcement Discretion (NOED). A NOED was submitted and approved in 2002 for the 2A DG. Several other one-time amendment requests to facilitate maintenance during shutdown conditions have been submitted. Longer required action completion time durations will reduce the regulatory burden associated with effectively maintaining the DGs.

4.3 Improved DG Availability During Shutdown

Performing DG overhauls at-power should reduce the risk associated with DG maintenance and the synergistic effects on risk due to DG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

4.4 Improved Ability to Support Maintenance Overhaul Durations

The three FM DGs have an estimated workload of 9 days (per 2 years) to complete all maintenance requirements. Each of these diesels has twelve ported cylinders.

The SACM DG has thirty-two valved cylinders resulting in many more parts than the FM DGs. The SACM DG has an estimated workload of 12 days (per 2 years) to complete most maintenance requirements (except the 5-yr and 10-yr PMs). This diesel also has a five-year preventive maintenance requirement that is estimated to take less than two weeks to complete. There is also a ten-year maintenance requirement with a duration that is estimated to be less than 28 days. The proposed twenty-eight-day required action completion time for the outage impact on the opposite unit is being requested to support these longer duration maintenance requirements. Work is underway to reduce the frequency of the five-year and ten-year maintenance requirements. This analysis assumes that the frequencies are not changed.

The proposed required action completion time extension of fourteen days is adequate to support periodic major overhauls of the DGs during at-power operation. For such cases, the intent would be that a major overhaul of each DG would be performed at a frequency of no more than once per DG per operating cycle.

5.0 Deterministic Assessment of the Proposed DG Required Action Completion Time Extension

The plant has four safety-related diesel generators and one Station Blackout diesel generator. Any combination of two of the DGs (one from each unit) is capable of supplying sufficient power for the operation of necessary engineered safety features (ESF) loads during accident conditions on one unit and shutdown loads of the alternate unit concurrent with loss of offsite power and for the safe and orderly shutdown of both units under loss of offsite power conditions. The diesel generators start automatically on a safety injection actuation signal (SIAS) or an undervoltage condition on the busses that supply vital loads

and are ready to accept loads within ten seconds. A Station Blackout (SBO) diesel generator, 0C Diesel Generator, can also be aligned to any of the four ESF busses. When all four SR DGs are operable, the design provides two independently capable and concurrently operating systems for safety injection, containment spray, and miscellaneous 480 volt auxiliary devices for the unit incurring the accident. In addition, the design provides power to operate two sets of equipment for shutting down the accident unit, including for example: two saltwater pumps, two service water pumps, two auxiliary feedwater pumps, containment cooling fans, and emergency turbine auxiliaries.

All necessary ESFs are duplicated and power supplies are arranged so that the failure to energize any one of the applicable busses, or the failure of one diesel generator to start, will not prevent the proper operation of the ESF systems.

The ESF electrical system has been designed to satisfy the single failure criterion as defined in Institute of Electrical and Electronic Engineers (IEEE) 279 (UFSAR Page 8.1-2, Bullet I, Page Revision 26).

5.1 Defense-in Depth

The impact of the proposed TS change was evaluated and determined to be consistent with the defense-in-depth philosophy. The defense-in-depth philosophy in reactor design and operation results in multiple means to accomplish safety functions and prevent release of radioactive material.

The CCNPP design is consistent with the defense-in-depth philosophy. The plant has diverse power sources available (that is, DGs and SBO DG) to cope with a loss of the preferred AC source (offsite power). The overall availability of the AC sources to the ESF busses will not be reduced significantly as a result of increased on-line preventive maintenance activities.

While the proposed change does increase the length of time a SACM DG can be out of service during unit operation, it will also increase the availability of the SACM DGs while the unit is shutdown. The increased availability of the SACM DG while shutdown will increase defense-in-depth during outages.

The CCPRA confirms the results of the deterministic analysis — the adequacy of defense-in-depth and protection of the public health and safety are ensured.

No new potential common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised.

Adequate defenses against human error are maintained. These proposed changes do not require any new operator response or introduce any new opportunities for human error not previously considered. Qualified personnel will continue to perform DG maintenance and overhauls whether they are performed on-line or during shutdown.

It is therefore acceptable, under controlled conditions, to extend the required action completion time in order to perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

5.2 Safety Margins

The proposed DG required action completion time license amendment does not change the compliance to any codes or standards that have been previously committed to or the margin to safety analysis acceptance criteria contained within the licensing bases.

As part of this amendment, the plant will be enhanced to help maintain the plant safety margin. The 0C DG ventilation system is being seismically hardened to support a 0.3g High Confidence of Low Probability of Failure (HCLPF) capacity. This modification provides a small reduction in the baseline core damage frequency and significant reduction in the risk associated with removing a DG from service.

6.0 Probabilistic Assessment of the Proposed DG Required Action Completion Time Extension

To further assess the overall impact of the proposed amendment on plant safety a plant specific PRA has been performed to quantify the change in risk. This evaluation included consideration of the Configuration Risk Management Program (CRMP) established at CCNPP pursuant to Maintenance Rule requirements. The risk evaluation was performed using the three-tiered approach suggested in RG 1.177, as follows:

Tier 1	PRA Capability and Insights
Tier 2	Avoidance of Risk-Significant Plant Configurations
Tier 3	Risk-Informed Configuration Risk Management

Evaluations for each of these tiers are provided below.

6.1 Tier 1, Analysis of Risk

Tier 1 is an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in the following metrics:

CDF	core damage frequency
ICCDP	incremental conditional change in core damage probability
LERF	large early release frequency
ICLERP	incremental conditional large early release probability

These metrics are evaluated in this section using the diesel generator data discussed below.

6.1.1 Diesel Generator Data used in Analysis of Risk

This subsection discusses the diesel generator unavailability, reliability, and common cause data used in the analysis of the proposed required action completion time extension.

6.1.1.1 Diesel Generator Unavailability Data

The baseline CDF and LERF terms refer to the average risk measures calculated using historical average equipment unavailability. These values are shown in Table 5 for both the at-power condition and the total unavailability. The at-power availability is used to represent the dedicated DG unavailability to its associated unit (for example, 1A and 1B DGs unavailability seen by Unit-1). The Total Unavailability (At-power plus Shutdown) represents the unavailability seen by the opposite unit (for example, 1A and 1B DGs unavailability seen by Unit-2). Only the Total unavailability value is provided for the 0C DG since it can be readily aligned to either unit.

For the 1A DG, the expected change in unavailability is based on shifting from four short at-power scheduled maintenance activities (about thirty hours each) and one shutdown overhaul maintenance activity (about 7 days) during a refueling cycle (i.e. 2 yrs) to two at-power maintenance activities. These activities would be one short planned activity (about 3 days) and one overhaul (about 7 days). For the FM DGs, a similar change would occur. These DGs would shift from two short at-power scheduled maintenance activities (30 hrs each) and one shutdown overhaul (7 days) every cycle (i.e. 2 yrs) to one short maintenance activity (2 days) and one overhaul performed at power (6 days) every cycle. The longer maintenance durations allow less DG tagout duration due to less DG maintenance preparation and return-to-service activities.

Although these changes reduce the overall time the DGs are tagged out, the full benefit of less unavailability is only realized on the 1A DG (per Table 5, 180 hr/yr. to 149 hr/yr.). The FM DG unavailabilities increase (per Table 5, 83 hr/yr. to 121 hr/yr.). Often due to shutdown work on the FM DG support systems (e.g. salt water and service water), the FM DG can be maintained while already out-of-service due to support system unavailability. In this case, the FM DG work is shadowed by the support system work. This evaluation does not credit the shadowing effect for at-power operations. For the FM DGs, there is considered to be an additional 60 hrs of at-power work per year per FM DG (per Table 5 Columns 1 and 3).

The impact of the less frequent 1A DG five-year and ten-year maintenance requirements are not considered in the unavailability estimates but are included as part of the sensitivity studies.

Table 5
Best Estimate Diesel Generator Unavailabilities
(Does not Include Support System Unavailability)

Diesel Generator	Unavailability At-power for dedicated unit				Unavailability Total (At Power + Shutdown)			
	Pre-CT Extension (PRA Values)	Current MR Performance Criteria	Post-CT Extension (PRA Values)	Post-CT MR Performance Criteria	Pre-CT Extension (PRA Values)	Current MR Performance Criteria	Post-CT Extension (PRA Values)	Post-CT MR Performance Criteria
	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
1A	89 hours per year	<300 hours per 2 years	149 hours per year	<400 hours per 2 years	180 hours per year	N/A	149 hours per year	<500 hours per 2 years
1B, 2A, 2B	61 hours per year	<200 hours per 2 years	121 hours per year	<300 hours per 2 years	83 hours per year	N/A	121 hours per year	<400 hours per 2 years
0C	N/A				194 hours per year	800 hours per 2 years	194 hours per year	<500 hours per 2 years

The post-extension Maintenance Rule Performance criteria will ensure that the risk increase due to this proposed amendment request (excluding the five-year and ten-year SACM required maintenance) will be below 1E-6. This was determined by setting all the diesels to their post MR performance criteria and comparing this to the pre-extension average diesel unavailability values. The benefit due to the seismic hardening of the 0C DG was not considered in the establishment of these criteria.

In addition to the above criteria, separate criteria are established for the five-year and ten-year SACM required maintenance. These criteria apply to both the 1A DG and the 0C DG.

five-year SACM Required Maintenance => fourteen day performance criteria per occurrence
ten-year SACM Required Maintenance => thirty day performance criteria per occurrence

When the combined impact of the base maintenance activities and the five-year and ten-year maintenance activities are considered, the increase in risk for Unit-1 remains below 1E-6, while the increase in risk for Unit-2 is slightly higher than 1E-6. The larger impact on Unit-2 is due to the cross unit impact that Unit-2 sees from the 1A DG five-year and ten-year maintenance activities. Unit-1 is assumed to be shutdown during these long-duration 1A DG maintenance activities and therefore is only impacted by the 0C DG five-year and ten-year maintenance activities. Both 1A DG and 0C DG long-duration maintenance activities impact unit-2.

The Maintenance Rule (MR) Criteria listed in Table 5 is based on Revision 1 of the Calvert Cliffs PRA (CCPRA). Revisions to the CCPRA can cause the MR Criteria to change. The CCPRA can change as a result of equipment performance, plant modifications, understanding of plant operations, infrequent maintenance evolutions (e.g. ten-year maintenance), etc. The MR Criteria will be adjusted as required consistent with the CCNPP MR program.

6.1.1.2 Diesel Generator Reliability Data

The skid-mounted components for each diesel generator set are modeled as a single component. Three failure modes are modeled as shown in Table 6. Interfacing system and components are modeled separately.

Table 6
Diesel Generator Reliability

Diesel Type	Failure Mode	Mean Failure Rate	Bases
SACM	Failure to Start	2.36E-3 per demand	The prior distributions are based on data from the manufacturer (SACM). This data was collected from 1986 through 1989. These prior distributions were Bayesian updated with plant experience from installation of the SACM diesels (August 1995 for DG 0C and April 1996 for DG 1A) to the present (September 2002).
	Failure to Run 1st Hour	2.65E-3 per hour	
	Failure to Run after 1st Hour	5.76E-4 per hour	Based on the SACM "Failure to Run 1st Hour" data times a reduction factor to account for decreased failure rate after one successful hour. Since SACM data was not available, the reduction factor is based on the ratio Failure Rate (FR) after 1st Hour to FR 1st Hour of the original PLG-0500 failure rates.
FM	Failure to Start	1.79E-3 per demand	The prior distributions are based on PLG-0500 generic failure rates and early plant specific data. The prior distributions were Bayesian updated with plant experience for the period of January 1992 through September of 1997.
	Failure to Run 1st Hour	6.28E-3 per hour	
	Failure to Run after 1st Hour	2.51E-3 per hour	This is a PLG-0500 generic failure rate.

There is significant experience of running the diesel generators for one hour and therefore its failure is modeled separately from the remaining required hours. The failure rate used for the "after the first hour" is more generic due to limited plant experience.

6.1.1.3 Diesel Generator Common Cause Data

The diesel generator common cause factors are taken directly from NUREG/CR-5497, Common Cause Failure Parameter Estimations. These are shown below:

Table 7
Diesel Generator Common Cause Data

Group	Type	Fail-to-Start	Fail-to-Run
Two (Used for the two SACM diesels)	Beta	3.12E-2	4.01E-2
Three (Used for the three FM diesels)	Beta	3.70E-2	4.99E-2
	Gamma	0.45	0.422

There is also common cause modeled between all five diesels. This common cause considers three contributors: the diesel generators (diesel engine, generator, fuel oil, control circuitry, etc.), the diesel output breakers, and the load shed relays. Due to the diversity of design between the SACM and FM diesels, an estimated likelihood of all five diesels failing included a factor of ten reduction of NUREG/CR-5497 Group of Five values for diesel generators. This estimate was added to the common cause likelihood that the diesel generator feeder breakers fail to close on demand and to the likelihood that three of the largest loads fail to load shed. See the Assumption section for more discussion of the load shed issue.

6.1.2 Change in Average Risk

RG 1.174 provides acceptance criteria for the change in CDF (core damage frequency) and LERF (large early release frequency). The guidelines are intended for comparison with a full-scope (including internal events, external events, full power, low power, and shutdown) assessment of the change in risk metric.

The criteria are conditional on the value of the baseline risk metric in that if the CDF is considerably higher than 1.0E-4 per reactor year then the focus should be on finding ways to decrease rather than increase it. CCPRA Revision 1 has a calculated internal and external event CDF of less than 1.0E-4 per reactor year. The guidance considers increases in CDF and LERF that are less than 1.0E-6 and 1.0E-7 respectively as very small.

The change in average risk was evaluated by comparing the pre-extension model with the post-extension model. Table 8 provides a summary of the model changes made to represent the proposed license amendment. Table 9 summarizes the results.

Table 8
Summary of Model Changes Considered in Delta Risk Analysis

Change	Pre-CT Extension Model	Post-CT Extension Model
Diesel Generator Unavailability	Uses values from Table 5, Columns 1 and 5	Uses values from Table 5, Columns 3 and 7
PORV Logic Modification	Assumes modification is implemented on both units	Assumes modification is implemented on both units
0C DG Seismic Modification	Does not credit this modification	Assumes modification is implemented
SACM 5-year and 10-year required maintenance	Not included since this maintenance has not yet been performed.	Not included since this low frequency maintenance would be required regardless of the status of the extended required action completion time. Both the 5-year and 10-year 1A DG maintenance activities will likely be performed shutdown.

Table 9
Expected Change in Average Risk
(reflecting benefit of 0C DG Seismic Modification)

Risk Metric	Risk Significance Criterion	Risk Metric Results	
		Unit-1	Unit-2
Base CDF	NA	6.4E-5	6.7E-5
Delta CDF	<1.0E-6	-1.9E-6	-2.9E-6
Base LERF	NA	5.6E-6	6.1E-6
Delta LERF	<1.0E-7	-1.5E-7	-3.2E-7

The benefit of improving the seismic ruggedness of the 0C DG outweighs the increased at-power unavailability that results from increasing the DG required action completion time.

6.1.3 Change in ICCDP and ICLERP

RG 1.177 provides acceptance criteria for ICCDP and ICLERP. The purpose of the numerical guidelines is to demonstrate that the risk increase is small and to provide a quantitative basis for the risk increase based on the aspects of the Technical Specification change modeled. A small risk increase is defined as ICCDP less than 5.0E-07 and ICLERP less than 5.0E-08.

ICCDP and ICLERP are defined numerically as:

ICCDP = [(conditional CDF with the subject equipment out of service)
– (baseline CDF with nominal expected equipment unavailabilities)]
* (duration of single required action completion time under consideration)

ICLERP = [(conditional LERF with the subject equipment out of service)
– (baseline LERF with nominal expected equipment unavailabilities)]
* (duration of single required action completion time under consideration)

For this evaluation, the conditional CDF and LERF terms refer to the risk of operating with a DG out of service and the remaining equipment at nominal expected unavailabilities. The post-extension model described in Table 8 was used for this evaluation.

The results of this evaluation are summarized in Table 10.

Table 10
ICCDP & ILERP

Diesel OOS	Unit 1 Impact				Unit 2 Impact			
	14 days		28 days		14 days		28 days	
	ICCDP	ICLERP	ICCDP	ICLERP	ICCDP	ICLERP	ICCDP	ICLERP
	DG 0C Available							
DG 1A	1.1E-06	5.0E-08	N/A	N/A	7.1E-07	3.9E-08	1.4E-06	7.7E-08
DG 1B	1.4E-07	5.7E-09	N/A	N/A	3.2E-07	1.2E-08	6.3E-07	2.4E-08
DG 2A	2.1E-07	8.7E-09	4.2E-07	1.7E-08	4.2E-07	2.4E-08	N/A	N/A
DG 2B	1.2E-07	4.3E-09	2.4E-07	8.6E-09	2.8E-07	9.3E-09	N/A	N/A
Diesel OOS	Unit 1 Impact				Unit 2 Impact			
	3 days		7 days		3 days		7 days	
	ICCDP	ICLERP	ICCDP	ICLERP	ICCDP	ICLERP	ICCDP	ICLERP
	DG 0C Unavailable							
DG 1A	7.7E-07	2.9E-08	N/A	N/A	6.0E-07	2.8E-08	1.4E-06	6.6E-08
DG 1B	1.5E-07	4.8E-09	N/A	N/A	1.8E-07	7.7E-09	4.2E-07	1.8E-08
DG 2A	1.1E-07	4.3E-09	2.5E-07	1.0E-08	2.7E-07	1.1E-08	N/A	N/A
DG 2B	1.1E-07	4.8E-09	2.6E-07	1.1E-08	4.2E-07	1.2E-08	N/A	N/A

Table 11
Impact of Multiple Diesels Out-of-Service

	1A DG (Bus 11)	1B DG (Bus 14)	2A DG (Bus 21)	2B DG (Bus 24)	0C DG Alignment	Unit 1 Days to 5E-7	Unit 2 Days to 5E-7
Two DGs Unavailable							
1	Unavailable	Unavailable	ok	ok	Bus 11	2.6	5.1
2	Unavailable	ok	Unavailable	ok	Bus 11	2.9	2.7
3	Unavailable	ok	ok	Unavailable	Bus 11	2.8	2.1
4	Unavailable	ok	ok	Unavailable	Bus 24	2.1	2.7
5	ok	Unavailable	Unavailable	ok	Bus 14	21.5	6.9
6	ok	Unavailable	Unavailable	ok	Bus 21	9.8	7.8
7	ok	Unavailable	ok	Unavailable	Bus 24	8.5	7.8
8	ok	ok	Unavailable	Unavailable	Bus 24	20.8	4.8
Three Diesels Unavailable (includes 0C DG)							
9	Unavailable	Unavailable	Unavailable	ok	Bus 11	1.3	1.6
10	Unavailable	Unavailable	ok	Unavailable	Bus 11	0.8	0.8
11	Unavailable	Unavailable	ok	ok	Unavailable	0.8	1.6
12	Unavailable	ok	Unavailable	Unavailable	Bus 24	0.9	0.7
13	Unavailable	ok	Unavailable	ok	Unavailable	0.6	0.6
14	Unavailable	ok	ok	Unavailable	Unavailable	0.9	0.8
15	ok	Unavailable	Unavailable	Unavailable	Bus 24	4.8	2.9
16	ok	Unavailable	Unavailable	ok	Unavailable	5.9	3.6
17	ok	Unavailable	ok	Unavailable	Unavailable	2.2	1.3
18	ok	ok	Unavailable	Unavailable	Unavailable	6.9	1.0

The cases shown in Table 11 were performed using solved cutsets using an approach similar to that of the sensitivity studies performed in this report. Cases 3 and 4 and Cases 5 and 6 show how the risk varies based on which bus the 0C DG is aligned to. Cases 5, 6, 7 and 8 shows that the impact of two Fairbanks Morse diesels out-of-service is considerably less than that of one SACM diesels and a Fairbanks Morse diesel (Cases 1, 2, 3 and 4). The three Fairbanks Morse case, Case 15, show the impact of three Fairbanks Morse diesels out-of-service is considerably less than other combinations of three diesel.

6.1.4 Risk Insights

1A DG Importance

Due to the interconnectivity of the sites electrical distribution system, 1A DG is the most important diesel to both Unit-1 and Unit-2. This importance is driven by these issues:

- Independence of 1A DG from other plant systems
- Rugged construction of the 1A DG building (wind resistant)
- Seismically Rugged (the 1A DG meets a Class 1 seismic design)
- Automatic start of the DG, and
- the 1A DG is aligned to an important 4kV bus.

These design features are especially evident in the external events analysis. Large seismic events, beyond design bases, can challenge the Turbine Building Service Water System (TBSRW). Large fires in the Turbine Building can also challenge the TBSRW. Since the Safety-Related Service Water and TBSRW (non-safety-related) are normally connected (TBSRW is isolated on SIAS), the failure of the TBSRW can result in the failure of the safety-related SRW due to a loss of inventory. This can, in turn, result in the failure of the Fairbanks Morse DGs.

0C DG Seismic Modification

The 0C DG Building was designed and installed to standard building codes. However, the diesel engine and generator are the same as the 1A DG. During the IPEEE walkdowns, it was noted that the 0C DG is generally rugged with a few exceptions associated with the 0C DG building HVAC. A modification was initiated to improve the seismic capacity of the HVAC system in support of this proposed license amendment. Improving the HVAC system to meet a 0.3g HCLPF provides a three percent reduction in total CDF for Unit 1 (4% for Unit 2) and significantly enhances the value of the 0C DG. Based on the expected DG unavailability following implementation of the proposed required action completion time extension a net risk reduction is predicted.

4kV Bus Importance

There are two issues that drive the importance of the 4kV busses: location of the motor-driven Auxiliary Feedwater pumps and providing power to charge the four station batteries.

Each unit has two ESF 4kV busses. Unit-1 has busses 11 and 14 and Unit-2 has busses 21 and 24. Each unit also has one motor-driven AFW pump and two turbine-driven AFW pumps. 4kV Bus 11 supports the Unit-1 motor-driven pump (AFW Pump 13) and 4kV Bus 24 supports the Unit-2 motor-driven pump (AFW Pump 23). These motor-driven pumps can be used to supply the opposite unit. For dual unit events, the CCPRA questions the availability of the turbine-driven pumps for each unit. If these are functioning, then the motor-driven pump is made available to support the opposite unit. It is therefore important to Unit-1 that Bus 24 is available and to Unit-2 that Bus 11 is available.

The second issue is the support to the chargers to maintain the batteries. Each 4kV bus has a separation classification called "facility." The facilities associated with these busses are as follows:

4kV Bus 11	Facility A
4kV Bus 14	Facility B
4kV Bus 21	Facility A
4kV Bus 24	Facility B

The four 125VDC busses are common to both Units. Each 125VDC bus is capable of providing key indications to both Units (e.g. steam generator water level indication). The 125VDC busses are each fed from a Unit-1 and Unit-2 480VAC charger (for a total of eight chargers). The facilities of the 125VDC busses and the ultimate 4kV support are:

125VDC Bus 11	Facility A	4kV Busses 11 or 21
125VDC Bus 12	Facility B	4kV Busses 14 or 24
125VDC Bus 21	Facility B	4kV Busses 14 or 24
125VDC Bus 22	Facility A	4kV Busses 11 or 21

Therefore, the loss of a single facility (busses 11 and 21 for Facility A or busses 14 and 24 for Facility B) will result in the loss of power to chargers supporting two of the four batteries. Loss of power to two busses of the opposite facilities maintains charging power to all the batteries. Due to the large amount of redundancy, this aspect of cross-unit dependence is not as significant as the motor-driven AFW pump.

Fire, Seismic and High Wind Impacts on Required Action Completion Time Extension

Seismic, Fire and Wind account for a large percentage of the risk associated with this proposed diesel generator extension. The following table shows the percentage of the risk due to external events associated with taking a diesel out of service.

Table 12
Percentage of CDF Change Due to Fire, Seismic and Wind

DG OOS	Unit 1	Unit 2
1A	57%	75%
1B	62%	43%
2A	57%	77%
2B	36%	45%
0C	64%	57%

If Fire, Seismic and Wind impacts were not used in this analysis the overall risk would drop by approximately 50%.

Hurricanes Impact on Required Action Completion Time Extension

The Wind Analysis includes hurricane and tornado impacts. Hurricanes account for greater than ten percent of the risks noted in this analysis. As noted in Section 6.2.4 a diesel generator will not be taken out of service if a hurricane warning is in effect. Also, an out-of-service diesel will be returned to service as soon as possible if a warning is issued. By procedure, if a hurricane is expected to strike within eight hours the units are placed in Hot Standby (Mode 3).

The hurricane analysis is conservatively performed assuming each unit is at power. Given the units will actually be shutdown for a number of hours prior to a hurricane strike the decay heat will be substantially reduced. Given the decreased decay heat and a controlled shutdown, the probability of core damage is significantly less than calculated.

The risk numbers shown in this analysis do not take credit for these compensatory measures.

6.1.5 Scope of PRA

The CCPRA is an at-power, internal and external events PRA. Both Level 1 and Level 2 are addressed. The external events considered are fire, seismic, and high wind (hurricanes and tornadoes). Both Unit-1 and Unit-2 are modeled. The Unit-1 models were modified with over two hundred changes to provide a risk assessment model that reflects Unit-2.

6.1.5.1 At-Power Model Structure

The accident sequences are developed using logic rules that relate equipment functions and operator actions to initiating events and other equipment functions and operator actions. RISKMAN software uses these rules to develop relationships that are represented by event trees. An event tree is a logical network that begins with an initiating event and progresses through a series of branches that represent the success or failure of the expected system function or operator action. These system functions or operator actions are referred to as top events. Each rule defines the selection criteria for a split fraction (the conditional failure probability of a top event) or a macro (a function that is set to true or false to indicate a plant status based on its associated rule). The split fraction values are contained in a file called a Master Frequency File (MFF). The bases for the MFF values comes from various sources including system analysis (fault-trees) and human action analysis.

Several sets of rules (eight models) using nine MFFs are used to represent the full scope of the CCPRA. The model definition and associated MFF are summarized below:

Table 13
CCPRA Model Structure

Internal/External	Model	Master Frequency File	Description
Internal	General Transient	Internal	Base file
Internal	LOCA	Internal	Base file
Internal	Steam Line Break	Internal	Base file
Internal	Flood	Internal	Base file
External	Fire – Auxiliary Building	Auxiliary Building	Human actions are degraded to reflect Auxiliary Building fires
		Intake Structure	Human actions are degraded to reflect Intake Structure fires
		Turbine Building (partial)	Human actions are degraded to reflect Turbine Building fires
		Yard Areas	Human actions are degraded to reflect Yard Area fires
External	Fire – Control Room/Cable Spreading Room	Control Room	Human actions are degraded to reflect Control Room fires
		Turbine Building (partial)	Human actions are degraded to reflect Turbine Building fires
External	Seismic	Bin 1	Human actions are degraded to reflect low g levels (low g to 0.281gs)
		Bin 2	Human actions are degraded to reflect mid g levels (0.282g to 0.663g)
		Bin 3	Human actions are degraded to reflect high g levels (0.664g to high g)
External	Wind	Wind	Base file with Wind Impact Top Events Added

Each model is constructed with a similar structure using six event-tree modules and a Plant Damage State (PDS) bin assignment module. These modules are seamlessly joined as though they are one event-tree within RISKMAN. The dividing point of each module reflects previous software limitations more than model structure concerns.

Table 14
Typical CCPRA Modules within each Model

GT Modules	Model
SUPPORT1	**Support Systems:** Primarily Electrical Busses and DGs
SUPPORT2	**Support Systems:** Primarily Mechanical Support Systems
GT1	**Front-line Systems:** Includes reactor and turbine trip functions
GT2	**Front-line Systems:** Includes AFW and HPSI in the injection mode
LT	**Front-line Systems:** Long-term; Includes Containment Spray and systems for re-circulation
PDS	**Plant Damage State:** Establishes the plant damage state for the Bin Assignment Rules.
Bin Assignment Rules	Uses the PDS macros to assign core damage sequences to a PDS (each PDS has a fixed fraction associated with LERF)

Note that although the structure for each model is the same, the individual module names differ for each model.

6.1.5.2 Shutdown Risk Assessment

The changes included in the proposed DG required action completion time license amendment are focused on allowing greater operational flexibility while at-power. The reduction in shutdown risk due to reduced DG shutdown unavailability and the potential avoidance of transition risk are not credited in this analysis.

6.1.6 PRA Detail Needed for Change

The CCPRA explicitly models the functions associated with the four DGs and the 0C DG in both the Unit-1 and Unit-2 PRA models. Key modeling features are discussed below.

6.1.6.1 Key Initiating Events

The Loss of Offsite Power (LOOP) is modeled by subdividing this initiator into seven initiating events (IEs). Each IE addresses a different LOOP duration: LOOP01 is less than one hour; LOOP02 is one to two hours; and so forth. The frequency for each IE is based on generic EPRI data and plant specific experience for the likelihood of a LOOP of a specific duration. This approach allows explicit responses to be modeled for the different durations. The grouping of the shorter duration LOOPs is based on plant functionality. The FM DGs can operate for one hour without ventilation. The DGs can run for over two hours using the fuel oil day tanks. The station battery is assumed to be able to last for about four hours given no SIAS actuation. The remaining times are subdivided based on risk impact. The more subdivisions used, the more accurate (and lower) the calculated CDF.

Loss of Offsite Power Initiating Event Frequencies

Loss of Offsite Power (LOOP) frequencies are parsed into seven time frames based on plant safety functions. The time frames are as follows:

Initiating Event	Description
LOOP01	Less than 1 hour
LOOP02	From 1 to 2 hours
LOOP04	From 2 to 4 hours
LOOP08	From 4 to 8 hours
LOOP11	From 8 to 11 hours
LOOP18	From 11 to 18 hours
LOOP24	From 18 to 24 hours

The generic frequencies for these initiators are taken from EPRI TR-110398, *Losses of Off-Site Power at U.S. Nuclear Power Plants – Through 1997*. Each LOOP frequency is extracted from Table 2-1 which is a graph of LOOP events and durations. The generic frequencies have been updated with plant experience. There has been one loss of offsite power event at CCNPP (in 1987). This LOOP was recovered before four hours had elapsed and is counted as a LOOP04.

Loss of 500kV or 13kV Busses

The DGs could also be required following the loss of a 500kV switchyard bus or a 13kV bus. The CCPRA model contains explicit initiators for both 500kV busses ("red" or "black") and both 13kV busses (11 or 21). In addition, the impact of a LOOP induced by stresses on the grid following a plant trip are included.

To develop a loss of a 500kV bus frequency industry data was reviewed for similar losses. This frequency was Bayesian updated with plant experience which shows that four such events have occurred at Calvert Cliffs: April 11, 1978; November 11, 1979; June 10, 1993; and February 27, 1996.

The loss of 13kV initiating events are based on an evaluation of individual component failure rates that result in the loss of these busses.

6.1.6.2 Event-Tree Modeling

Unit-to-Unit Interaction

To effectively model the role of the opposite unit DGs, both unit PRAs include all four DGs, the 0C DG, and associated electrical and mechanical systems necessary for their operation. The model also includes the consideration that some initiators cause both units to trip (for example, LOOP, hurricane, some fires, loss of 125VDC Bus 11, etc.).

Diesel Unavailability

Five top events are used to model the out-of-service unavailability of each diesel generator. Since it is a site practice to remove only one of the five diesels from service at any given time, the separate modeling of the unavailability provides an easy means to account for the mutually exclusive nature of this unavailability. For the three water-cooled Fairbanks Morse diesels the unavailability of service water is also considered in these top events.

Diesel Common Cause

The diesel generator common cause is modeled at several different levels:

- Between like equipment supporting a single diesel
- Between like diesels (between the two SACM diesels and between the three FM DGs)
- Between all like and unlike diesels

The common cause between like equipment supporting a single diesel is modeled within the fault-tree for each diesel. The common cause between like diesels is modeled using conditional split fractions within the appropriate diesel generator top events. The common cause between all the diesels (including 0C DG) is modeled using a separate top event (Top Event GC) within the event tree. If this top event fails, then all the diesels are set to failure. Top Event GC considers the potential for common cause failure of the 4kV feeder breakers or the common cause failure of multiple load shed relays.

This comprehensive treatment of common cause is not limited to the diesel generators. This approach is used throughout the CCPRA. Other key common cause impacts related to the diesel generators are 125VDC batteries, SRW pumps, SW pumps, ESFAS UV channels, 4kV load breakers, and 120 VAC inverters.

0C DG Substitution

During DG maintenance activities the model assumes that 0C DG is pre-aligned to the bus associated with the out-of-service DG and cannot be re-aligned to another bus in response to an initiating event. If all DGs are available prior to the trip and only a single DG fails post trip, 0C DG is assumed to be preferentially aligned to the 4kV Busses as shown in Table 15.

Table 15
0C DG Alignment Preference

Order	Unit-1 Model	Unit-2 Model
1st	4kV Bus 11	4kV Bus 24
2nd	4kV Bus 24	4kV Bus 11
3rd	4kV Bus 14	4kV Bus 21
4th	4kV Bus 21	4kV Bus 14

4kV Busses 11 and 24 power the motor-driven Auxiliary Feedwater Pumps for their respective units and are therefore the more important 4kV busses. If both DGs on a given unit fail, then 0C DG is aligned to the unit in the blackout condition. For example, if DGs 1A, 2A, and 2B fail in a Unit-1 evaluation, then 0C DG is considered aligned to 4kV Bus 24 (Unit-2). See the Assumptions Section for addition discussion of this topic.

Operator Actions

Several operator actions that are directly associated with the alignment of the diesel generators are included in the models. These include:

Table 16
Diesel Generator Human Actions

Action	Top Event	Description	Available Time	HA Failure Likelihood	Comments
BHEC3A	GO	Align Fuel Oil Makeup to 0C DG after LOOP	8 hrs	2E-4 to 3E-3	Timing is based on time to deplete the 0C DG fuel day tank.
BHEC3B	GO	Restart 0C DG Following Fuel Oil Depletion	3.5 hrs	3E-4	This action is questioned if 0C DG shutdowns due to lack of fuel. Action BHEC3A is assumed to fail.
BHEC4A	GS GK GL	Start, Align and Load 0C DG to a 4kV Bus	20 mins 45 mins 2 hours	6E-3 9E-4 to 4E-1 2E-1 to 3E-1	Values vary based on: - number of DGs that failed - whether the failure is early or late - available time Additional degradation is considered for fire and seismic events.
BHEADU	AD	Align 1A DG to 4kV Bus 24	1 hr	2E-1	Applies to Main Control Room fires only. Value is a conservative estimate.
BHEFV1	FV	Align 1A DG or Off-site Power on 0C DG failure	1 hr	1E-1 to 2E-1	Applies to Main Control Room fires only. Values are estimated. Values vary dependent on the status of off-site power.

The impact of failing human actions BHEADU and BHEFV1 are included as sensitivity studies.

6.1.6.3 Diesel System Models

SACM Diesel Generators (1A DG and 0C DG)

The SACM Diesel Generators are modeled using two top events for *each* diesel generator. For each diesel, one top event addresses planned and unplanned unavailability and a second top event addresses the likelihood that the diesel will start and run for its required mission given it is available. The likelihood that the diesels fail to perform their missions is determined using fault-tree analysis.

Both 1A DG and 0C DG are relatively independent from the remainder of the plant. They are each housed in their own buildings. Other than the undervoltage signal from ESFAS and control power to close the DG onto the safety-related bus there are no external supports required. The following internal support systems are modeled in detail for each top event:

- DG Control Relays
- Fuel Oil Makeup
- Building Ventilation – Including direct room cooling for the DGs
- Electrical Supports – 125VDC, 480VAC, 4kV
- DG Fluid Cooling Systems
- Air Start System

Common cause between like system components is included in the detailed fault-tree models used to represent these models. Common cause between the diesels is discussed above in Event Tree Modeling.

Fairbanks Morse Diesel Generators (1B, 2A and 2B DGs)

The Fairbanks Morse Diesel Generators are also modeled using two top events for *each* diesel generator. For each diesel, one top event addresses planned and unplanned unavailability and a second top event addresses the likelihood that the diesel will start and run for its required mission given it is available. The likelihood that these diesels fail to perform their missions is determined using fault-tree analysis.

The Fairbanks Morse DGs are located in the separate rooms within the Auxiliary Building. They require several plant support systems including 125VDC power, 480VAC power, an undervoltage signal from ESFAS, as well as the plant Service Water System. The following internal support systems are modeled in detail for each top event:

- DG Control Relays
- Fuel Oil Makeup
- Room Ventilation
- SRW Supply CV
- Air Start System

Common cause between like system components is included in the detailed fault-tree models used to represent these models. Common cause between the diesels is discussed above in Event Tree Modeling.

6.1.6.4 Truncation Limits

For each initiating event the CCPRA quantification process post-processes the RISKMAN sequence output to obtain accurate CDF/LERF values with a sufficient number of sequences to ensure resolution while simplifying the sequence results. The CDF and LERF values associated with each initiating event are extrapolated such that the CDF/LERF has less than a one-percent change in CDF/LERF for a decade deeper truncation limit.

The truncation limits are set per-initiating event based on the post-processed results. These truncation limits vary from 10^{-10} to 10^{-15}.

6.1.7 PRA Assumptions

Diesel Generator Related Assumptions

1. Diesel unavailability is assumed to be mutually exclusive.

The TS currently have a seventy-two hour limitation for the out-of-service condition of one DG per unit. Site practice is to remove only a single diesel generator, including the 0C DG, from service at any one time.

The impact of this assumption is that when one diesel generator is out of service, the other diesels have a reduced likelihood of failing since they can not be out of service for maintenance.

2. 0C DG is assumed pre-aligned to bus of out-of-service DG.

Pre-aligning the 0C DG to the out-of-service bus is a practice that is typically used to maximize the reliability of the impacted ESF bus. The 0C DG is electrically isolated from the ESF busses by two breakers (one Class 1E and one non-Class 1E) and a Class 1E disconnect switch. To pre-align the 0C DG, the local disconnect switch is shut to the effected ESF bus. This removes the need for local action in the applicable switchgear room.

The impact of this assumption is that when one DG is out of service, the 0C DG will be dedicated to the impacted bus and only a Main Control Room action is used to start and load the diesel. The CCPRA assumes that once the 0C DG is pre-aligned, it will not be re-aligned following the initiation of an accident. This is conservative since equipment failures including the status of the other DGs may make re-aligning the 0C DG a necessity.

3. Post-initiator with all DGs initially available, 0C DG will be aligned to the most important bus on the unit with the greatest need.

4kV Bus 11 is the most important bus for Unit-1 and 4kV Bus 24 is the most important bus for Unit-2. As long as at least one 4kV bus is available on both Units or there is a blackout condition on both units, the unit with the greatest need is considered the evaluated unit.

CCNPP procedures do not direct 0C DG to a particular bus. This approach provides maximum operational flexibility. Since the 0C DG is a common diesel to both units, it is evaluated in the PRA for each unit. This is also true for the DGs except that they are aligned to a dedicated bus. This is appropriate due to the conservative assumption that the 0C DG can not be re-aligned once on a bus and the extensive accounting for other cross-system dependencies. For example: AFW Pump 13 can be used by Unit-2 during a LOOP only if a Unit-1 turbine-driven AFW pump is available and supports systems including power to the AFW Pump 13 is available.

The table below illustrates the possible alignments and where they are different between the unit models.

Table 17
0C DG Alignments

1A DG (Bus 11)	1B DG (Bus 14)	2A DG (Bus 21)	2B DG (Bus 24)	0C DG U1 Model Alignment	0C DG U2 Model Alignment	Alignment Different Between Units
Unavailable	n/a	n/a	n/a	Bus 11	Bus 11	No
n/a	**Unavailable**	n/a	n/a	Bus 14	Bus 14	No
n/a	n/a	**Unavailable**	n/a	Bus 21	Bus 21	No
n/a	n/a	n/a	**Unavailable**	Bus 24	Bus 24	No
Fails	Works	Works	Works	Bus 11	Bus 11	No
Works	**Fails**	Works	Works	Bus 14	Bus 14	No
Works	Works	**Fails**	Works	Bus 21	Bus 21	No
Works	Works	Works	**Fails**	Bus 24	Bus 24	No
Fails	**Fails**	Works	Works	Bus 11	Bus 11	No
Fails	Works	**Fails**	Works	Bus 11	Bus 11	No
Fails	Works	Works	**Fails**	Bus 11	Bus 24	**Yes**
Works	**Fails**	**Fails**	Works	Bus 14	Bus 21	**Yes**
Works	**Fails**	Works	**Fails**	Bus 24	Bus 24	No
Works	Works	**Fails**	**Fails**	Bus 24	Bus 24	No
Fails	**Fails**	**Fails**	Works	Bus 11	Bus 11	No
Fails	**Fails**	Works	**Fails**	Bus 11	Bus 11	No
Fails	Works	**Fails**	**Fails**	Bus 24	Bus 24	No
Works	**Fails**	**Fails**	**Fails**	Bus 24	Bus 24	No
Fails	**Fails**	**Fails**	**Fails**	Bus 11	Bus 24	**Yes**

As seen above, our approach to modeling 0C DG results in three cases where the alignment of the 0C DG is different between the units. None of these cases are associated with the planned unavailability of a DG.

4. **Repair of a failed diesel is assumed to be unlikely and therefore not credited.**

Recovery of the LOOP is considered within the development of the LOOP initiating events. Each of the seven LOOP initiating events represents a discrete LOOP duration. The diesel mission times are associated with a specific LOOP initiating event. If a DG fails, it can be recovered by the 0C DG. However, repairing a DG is not considered due to the added timing complexity. .

5. **During ESF UV sequencer operation, it is assumed that three of the largest loads must fail to load shed before the DG is assumed to fail.**

When the undervoltage devices sense a low bus voltage condition, actuation logic will load shed selected loads and start the associated DG. Failure to load shed one or more loads could degrade the diesel or the associated bus resulting in a low voltage or low frequency condition. Design calculations show that the load shed margin is low in that one or two loads failing to load shed would result in the minimum voltage being exceeded. However, a failure that occurred at CCNPP during an integrated ESF test resulted in a FM DG picking up significant load. The bus impact was minimal. A three-load failure criteria is a compromise in that it is a slightly higher number of load failures than the design calculation showed as acceptable but a much lower than the number of failures seen during an actual plant event in which the diesel performed acceptably.

6. **Diesel failure rate and common cause likelihood are assumed to remain the same.**

The changes to the TS directly impact the DG unavailability assumed in the PRA. However, no changes were made to the diesel failure rates to start and to run or to the common cause likelihood. With the increase in operational flexibility, there is a potential that these failure rates may improve. Therefore, this assumption is considered conservative.

7. **Shutdown risk and transition risk are assumed to further justify the requested change.**

It is anticipated that the 1A DG unavailability will decrease as a result of this proposed amendment (Table 5, Column Post-CT Extension Values). In addition, transitions to lower modes of operation may be avoided. The risk reduction associated with these improvements is not explicitly calculated in the analysis supporting this change.

8. **The Diesel Generators will continue to be worked around the clock while out of service for maintenance.**

The DGs will continue to receive high priority from Operations and Maintenance personnel. This will ensure that the DGs are returned to service in the minimal amount of time. This assumption is necessary to support the expected reduction in total unavailable hours incurred as a result of the required action completion time extension.

Other Assumptions that Could Impact this Proposed Submittal

9. **Various values are assumed for the likelihood that the steam generators underfill or overfill on loss of Auxiliary Feedwater (AFW) flow control.**

The CCNPP AFW system uses air-operated flow control values to modulate the feedwater flow. These valves fail open on loss of power and on loss of instrument air. The operator action to properly control AFW flow is modeled in Top Event HX. On failure to control flow, the model estimates the likelihood that the failure will result in an underfill or over feed condition. These values are estimated for the three conditions described below:

1. **Flow Control supports and Steam Generator Level indication available.**

   In this case it is assumed slightly more likely that an overfill condition will exist. As AFW Flow control setpoints are sufficient to remove all decay heat, if the operator does nothing, as decay heat decreases the Steam Generator Levels will increase. Thus, it is expected to have a 20/80 split between underfill and overfill.

2. Flow Control supports fail and Steam Generator Level indication available.

Given that the Flow Control Valves fail open on loss of power or air it is even more likely that a failure to control level will lead to an overfill condition. (Underfill is fifty percent less likely than when flow control power is available.) The value used (0.10) remains significant due to the potential for improper local control or the potential for operators to trip the AFW pumps if level starts approaching overfill.

3. Flow Control supports fail and no Steam Generator Level indication is available.

Given that the FCVs fail open and operators have no indication of a high level, it is very likely that an overfill condition will result from a failure to control flow. Operators are unlikely to trip the AFW Pumps if S/G level indication is not available. This value is estimated at 0.02 (one fifth of value with S/G indication available).

The availability of the DGs directly impacts the availability of the AFW flow control support systems and Main Control Room indication. Varying these values is included as a sensitivity analysis.

6.1.8 Base PRA Results

The base PRA used for this proposed amendment contains both internal and external events for Unit-1 and Unit-2. Table 18 shows the results of the Unit-1 and Unit-2 CCPRA Revision 1 model.

Table 18
CCPRA Revision 1 Results

Hazard	CDF		LERF	
	Unit-1	Unit-2	Unit-1	Unit-2
Internal Events	**3.34E-5**	**3.40E-5**	**1.86E-6**	**1.89E-6**
General Transients	2.64E-5	2.69E-5	1.35E-6	1.37E-6
Flood	1.87E-6	1.93E-6	7.26E-8	7.64E-8
LOCA	4.61E-6	4.63E-6	4.11E-7	4.15E-7
SLB	5.34E-7	5.33E-7	2.64E-8	2.64E-8
External Events	**3.05E-5**	**3.26E-5**	**3.78E-6**	**4.18E-6**
High Winds	5.14E-7	6.24E-7	1.87E-8	2.24E-8
Fire	2.01E-5	1.99E-5	2.03E-6	2.05E-6
Seismic	9.89E-6	1.21E-5	1.73E-6	2.11E-6
Aircraft	<1.0E-6*	<1.0E-6*	NA	NA
Turbine Missile	<1.0E-7*	<1.0E-7*	NA	NA
Total	**6.39E-5**	**6.66E-5**	**5.64E-6**	**6.07E-6**

* The change in risk due to these hazards was not addressed in this analysis and is not included in the totals.

6.1.9 PRA Sensitivity/Uncertainty Analysis

To evaluate the sensitivity of the DG required action completion time to variations of key contributing parameters, a series of 78 sets of sensitivity cases were evaluated. Each set evaluates with the estimated DG unavailabilities pre-extension versus post-extension for the varied parameters.

The results of the sensitivity study indicate that there is a high degree of confidence that the DG required action completion time extension, coupled with the 0C DG modification, results in a net risk reduction. The 0C DG modification causes an annual reduction in the Unit 1 CDF of 1.90E-06 and an annual reduction in the Unit 2 CDF of 2.9E-06.

The Unit 1 sensitivity cases results appear in Figure 1.0. The Unit 2 sensitivity results appear in Figure 2.0. None of the cases evaluated show a net risk increase.

The sensitivity evaluation is based on varying these key parameters:

- The frequency of a hurricane (Base, Half, Double)
- The frequency of a loss of off-site power (Base, Half, Double)
- Whether the RCP motor failure causes a RCP trip without operator action (Yes, No)
- The failure likelihood of the RCP seals (Base, Half, Double)
- The failure likelihood of the operators controlling AFW Flow (Base, Half, Double)
- The failure likelihood of the operators to recover from a SG overfill (Base, Half, Double)
- The failure likelihood of the operators to align the opposite Unit AFW pump (e.g. AFW Pump 23 aligned to Unit 1) (Base, Half, Double)
- The failure likelihood of the operators to align the 120 VAC inverters to the back-up bus (Base, Half, Double)

These parameters are considered key based on cutset examination. These parameters dominate the cutsets that contain DGs OOS. The six RCP seal cases (the two RCP motor trip cases times the three RCP seal failure likelihood cases) are used as the base framework of the sensitivity study. Each of the remaining 6 parameters are varied individually (2 cases each [half and double]). This results in a total of 78 (78=2*3+6*2*6) cases for each Unit. Each of these cases is evaluated with the estimated DG unavailabilities pre-extension versus post-extension. This results in 78 sets of delta core damages for each Unit.

Of the parameters evaluated, AFW Flow control is the most important. When the human action failure rate is doubled the delta CDF increases by about 70% for both Unit 1 and Unit 2. This is by far the most important parameter. AFW flow control during normal loss of decay heat removal scenarios is extremely reliable. Loss of indication or loss of remote flow control capability complicates AFW flow control. Some of the most significant contributors to AFW flow control losses given a DG is unavailable are external events.

For example, during an extremely large earthquake, the Fairbanks Morse DGs may fail due to loss of service water. Without the 1A DG and 0C DG, the 125 VDC battery will eventually deplete. Without 125 VDC power, operations would soon be trying to control the turbine driven AFW pumps locally with local indication only. Other external events cause similar problems. High wind scenarios can cause the failure of the 0C DG since it is not designed to withstand severe winds. Two other DGs failures on the same facility can cause a spurious safety system actuation. This complicates AFW flow control through a loss of compressed air. Within internal events, the dominant scenarios are a spurious ESFAS actuation and losses of the 500kV busses.

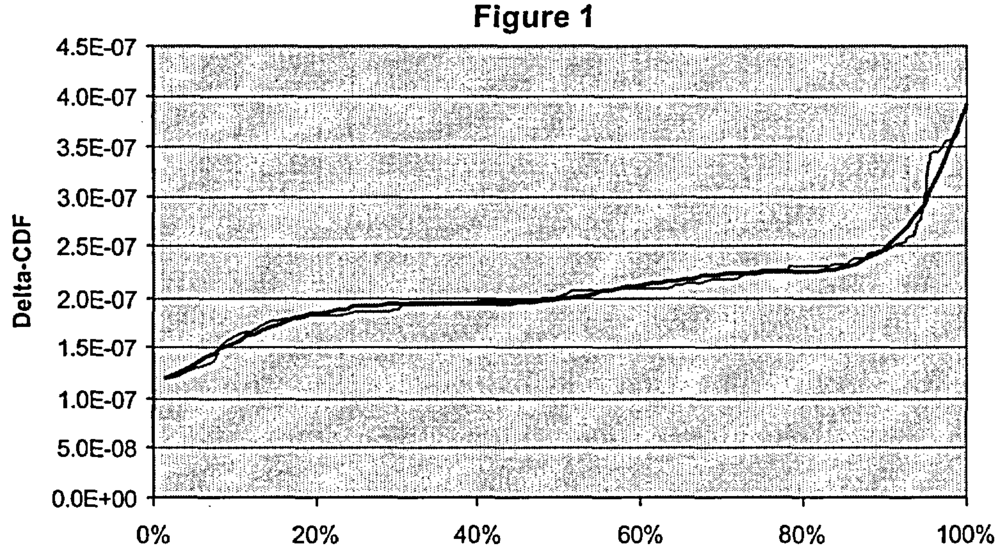
For Unit 2, the operator action to mitigate steam generator overfill is quite significant. When this human action doubles, the delta CDF increases by about 40%. The importance of this human action is driven by losses of flow control. If flow control is lost the steam generators can be underfed (i.e. direct core damage),

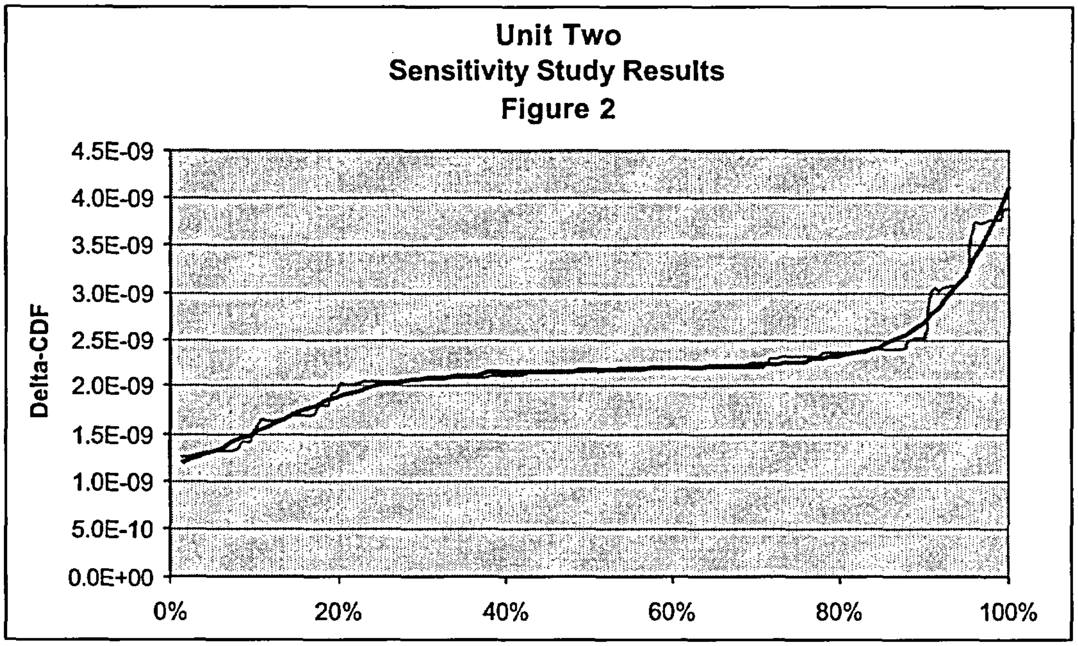
or overfed. An overfeed fails the operating turbine driven AFW pump, and requires operations to clear the lines of water and start the stand-by AFW pump. The Fairbanks Morse DGs are more dependent than the SACM DGs (e.g. SRW, electrical bus work, etc.). As Unit 2 has no dedicated SACM DGs, the key AFW related control systems like electrical power and air are more vulnerable on Unit 2. The AFW flow control valves fail open on loss of air or electrical support. It is more likely that an overfill will occur on a loss of air or electrical support. This causes a higher fraction of AFW flow control losses to be overfills on Unit 2. This in turn increases the importance of this action to Unit 2.

The remaining parameters cause a 10% to 20% increase in the delta CDF for a doubling of the parameter in question.

Based on the results of the sensitivity study, there is a high degree of confidence that the DG required action completion time extension coupled with the 0C DG being more seismically rugged results in a risk reduction.

Unit One
Sensitivity Study Results
Figure 1





Using the Post-CT unavailability data (from Table 5) causes a much smaller CDF increase on Unit 2 than the Unit 1. This is largely due to the 1A DG. For Unit 1, the at-power 1A DG unavailability increases from 89 hrs to 149 hrs (per Table 5). For Unit 2, the at-power DG unavailability decreases from 180 hrs to 149 hrs (per Table 5). The 1A DG is the most important site DG. This is especially true for external events scenarios that can disable all SRW and cause off-site power to be lost. The lost of SRW fails the FM DGs. The reduction in at-power 1A DG unavailability from the Unit 2 perspective negates much of the risk increase associated with increasing the at-power FM DG unavailability.

6.1.10 Compensatory Measures for Reducing Risk

When a DGs are removed from service, the other in-service DGs and 4kV will be flagged off to prevent inadvertent degradation.

6.1.11 Quality of CCNPP PRA

CCNPP utility personnel have constructed the CCPRA with a strong commitment toward developing a complete and accurate PRA. This commitment can be seen through the following elements:

- Formal qualification program for the PRA staff
- Use of procedures to control PRA processes
- Independent reviews (checks) of PRA documents
- Comprehensive PRA Configuration Control Program
    - Plant change monitoring program
    - Process to control PRA quantification software
    - Active open items list
    - Interface with the site corrective action program
    - Process to maintain configuration of previous risk-informed decisions

- Peer reviews
- Participation in the CEOG cross comparison process
- Incorporation, where applicable, of CEOG PRA Technical Positions
- Commitment of continuous quality improvement

The CCPRA Revision 0 was peer reviewed in November 2001. The CCPRA Revision 1 Model contains several refinements, but uses techniques and practices similar to the peer reviewed revision.

Considering the scope (internal and external events), level of detail, processes, and excellent peer review results, the CCPRA is sufficient to support a technically defensible and realistic evaluation of the risk associated with this amendment request.

The following sub-sections provide a summary of the CCPRA Revision 0 peer review, the changes made between Revision 1 (used for this amendment) and Revision 0, and a brief history of the CCPRA since the IPE submittal.

6.1.11.1 CCPRA Revision 0 Peer Review

The CCPRA Revision 0 internal events model has been reviewed as part of the Combustion Engineering Owners Group (CEOG) Peer Review Process in November 2001. The peer review team consisted of five full-time members. Four members were utility personnel and the remaining member was the team leader/facilitator from Westinghouse. Two of the reviewers had participated in previous CEOG peer reviews. The reviewers had a combined PRA experience of approximately seventy-five years. It should also be noted that CCNPP PRA personnel have participated in every CEOG sponsored peer review and through this process have gained considerable insight and experience as to the technical requirements for developing an effective PRA.

Note that the risk assessment for this proposed amendment is based on CCPRA Revision 1. The changes between the Revision 0 and Revision 1 are discussed below.

The peer review addressed eleven technical elements. The team uses a checklist for each technical element as a framework to evaluate the scope, comprehensiveness, completeness and fidelity of the PRA being reviewed. Each item on the checklist is evaluated with a grade:

Exceeds

Meets

Marginal

Inadequate

Items evaluated other than meets are documented with Facts and Observations (F&Os). Each F&O is provided with a level of significance (A: Extremely Important, B: Important, C: Desirable, D: Minor, O: Observation, S: Superior).

At our request, the team also evaluated the CCPRA against the draft ASME PRA Standard, Revision 14A. This was accomplished by using the ASME Standard supporting requirements as sub-tier criteria. The team was provided with a self-assessment of the CCPRA to the draft ASME PRA requirements. The team used this self-assessment to aid in gauging the technical adequacy of the CCPRA.

All eleven technical elements were found to "Meet" requirements.

The review team found several strengths. Below is an excerpt from the peer review report.

> *"The review found several strengths. The Calvert Cliffs PRA staff is knowledgeable and is committed to improving the Calvert Cliffs PRA. Calvert Cliff's management is also committed to improving the quality of the PRA, as witnessed by the resources dedicated to the maintenance and application of the PRA. Throughout the peer review, the Calvert Cliffs PRA staff was cooperative and helpful. The documentation supporting the PRA is the most extensive and thorough of all PRAs reviewed to date and was readily available to the review team, which greatly facilitated the review. Prior to the arrival of the peer review team, the Calvert Cliffs PRA staff performed a self-assessment against the NEI criteria using the peer review checklists and a self-assessment against the requirements presented in draft 14A of the ASME PRA standard. The results of these self-assessments were documented with an annotated checklist that cross-correlated both sets of requirements. This self-assessment appears to have been thorough and objective.*
>
> *The Calvert cliffs peer review also included a review of the Calvert Cliffs PRA against the ASME High Level Requirements (HLRs) for 9 of 10 key PRA areas. Internal Flooding is considered as not being assessed since five of the seven Internal Flooding HLRs were not reviewed in sufficient depth to evaluate the compliance. Although the LERF element was reviewed, the documentation HLR for LERF was not assessed due to a delay in locating the MAAP analyses.*
>
> *Overall, the Calvert Cliffs PRA met with the requirements of 45 of 46 assessed ASME PRA Standard HLRs for a Category II PRA. (Note: Compliance with an HLR does not imply 100% compliance with all Supporting Requirements (SRs) for that HLR.) One HLR was not met due to the lack of uncertainty analyses.*
>
> *Thus, it is concluded that the Calvert Cliffs PRA is sufficient to support Category II risk-informed applications with support from deterministic analyses to address any individual weaknesses that may impact the specific analyses."*

A total of forty-three F&Os were identified. No "A" level significant issues were identified. The issues that were identified are focused on localized areas of the PRA.

An estimated core damage frequency reduction of five to ten percent is expected as a result of incorporating the significant issues identified by this review. These issues are discussed below.

Of the 213 sub-elements reviewed, eighty-seven percent were evaluated as meeting or exceeding the requirements.

Three sub-elements were graded as "Inadequate." All three are associated with the lack of an uncertainty analysis. The need to perform this analysis has been previously identified. The uncertainty analysis for this proposed required action completion time extension is addressed by a series of sensitivity analyses.

A grade of "Exceeds" was assigned to four sub-elements.

- IE-16 Traceable initiating event documentation
- DA-15 Documentation of failure probabilities that do not fit into the basic event database
- ST-4 Reactor pressure vessel failure modeled appropriately
- L2-14 Containment capability is analyzed under severe accident conditions

The below table summarizes the results:

Table 19
Peer Review Sub-element Grades

Grade	Number of Sub-elements	Percent
Exceeds	4	2%
Meets	181	85%
Marginal	25	12%
Inadequate	3	1%

A total of forty-three Facts and Observations (F&Os) were written.

Table 20
Facts and Observations Types

Type	Description	Number
A	Extremely Important	0
B	Important	11
C	Desirable	18
D	Minor	1
O	Observation	13
S	Superior	1
	Total	**43**

6.1.11.2 Peer Review "B" Level Facts & Observations

A summary of the eleven "B" level F&Os is provided below:

IE-01 The CCPRA uses a SGTR initiating event frequency based on NUREG/CR-5750 which covers industry experience up to 1995. A CE Owners Group (CEOG) document issued in June 2000 has a new SGTR frequency that is about twenty percent lower.

CCNPP Response: The newer data will be incorporated in a future PRA update. It is expected that this will result in less than a one percent reduction in calculated internal event CDF. This has

been added as an open item (CRMP 428) in the CCPRA PRA configuration control program. Consistent with our configuration control process (EN-1-330) no Issue Report has been initiated since this is an update to more recent data with a minimal change in calculated CDF.

Required Action Completion Time Extension Impact: The DGs play only a small role in the mitigation of a SGTR. Incorporation of this F&O will not negatively impact this submittal.

IE-02 The CCPRA does not explicitly model the spurious RCP seal failure and spurious primary safety relief valve opening as initiating events.

CCNPP Response: This is a non-conservative error. A new open item (CRMP 420) has been added to the CCPRA configuration control program to address this issue. A preliminary review of the industry data associated with these initiators shows no events that would be applicable to CCNPP. It therefore appears that the addition of these initiating events will have minimal to no impact. IR3-070-503 has been initiated to capture this issue.

Required Action Completion Time Extension Impact: The inclusion of the above events is expected to result in no impact on this submittal.

IE-05 The CCPRA uses a draft reference for the bases of its interfacing LOCA initiating events. A CCPRA open item (CRMP 199) had been previously issued in June 2000 to require an update of this analysis. The frequencies used for these initiators are consistent with typical industry values so this should not have a significant impact.

CCNPP Response: As stated by the reviewers, this issue is not expected to cause any significant impact. The completion of the documentation for the interfacing LOCA has been prioritized after the other more significant issues. The issue had been previously captured in our configuration control program as open item (CRMP 199). It is currently planned for completion by the end of 2003. Consistent with our configuration control process (EN-1-330), no Issue Report has been initiated since this issue is associated with ongoing documentation of the PRA and has minimal risk impact.

Required Action Completion Time Extension Impact: The interfacing LOCA initiating events are sent directly to core damage. The issue has no impact on the risk analysis used to evaluate the change in the DG availability.

IE-07 The failure mode associated with the spurious actuation of the over-current or 86-lockout device is not considered as a potential initiating event. This failure is also not considered in the accident mitigation portion of the model.

CCNPP Response: This is a non-conservative error. This issue is a potential addition to our initiating events and/or an increase in the initiating event frequency associated with the failure of the safety-related 4kV busses. A new open item (CRMP 419) has been added to the CCPRA configuration control program to address this issue. The addition of this issue is expected to result in a one to four percent increase in the calculated CDF. IR3-070-504 has been initiated to capture this issue.

Required Action Completion Time Extension Impact: The spurious actuation of the lock-out relay or over-current protection causes the failure of the 4kV bus in question regardless of the status of the DG dedicated to the bus. For this to impact the importance of the DGs, off-site power feeds to the other SR busses must be lost concurrent with this event. As there is no common mode failure, the likelihood of this set of circumstances is so small that there is essentially no impact on the required action completion time extension risk analysis.

AS-01 The CCPRA models single and multi-tube SGTRs. For multi-tube SGTRs, no recovery is currently credited. Crediting recovery could reduce the calculated CDF by fifteen percent.

CCNPP Response: This is the most significant finding of this peer review. The CCPRA models both single tube and multi-tube SGTRs. For multi-tube ruptures, we have taken a conservative approach pending time to more thoroughly address this issue. The issue was captured as an open item (CRMP 285 and 336). However, the perspective of the reviewers helped clarify the appropriate approach for modeling this issue. The improved modeling was incorporated into the CCPRA Revision 1 model.

Required Action Completion Time Extension Impact: The risk analysis for this required action completion time extension includes the resolution of this issue.

AS-04 This finding recommends the incorporation of the new RCP seal LOCA model. This model is currently under review by the NRC. Implementation guidance is also under development by the CEOG.

CCNPP Response: We have been working to incorporate the new RCP Seal LOCA model. An open item (CRMP 138) in the CCPRA configuration program had already captured this issue. The new RCP Seal model will be included into a future PRA update. Consistent with our configuration control process (EN-1-330) no IR has been initiated since this is an update to more recent model. In addition, the new CEOG RCP model is not fully developed.

Required Action Completion Time Extension Impact: A sensitivity analysis is included to understand how this issue impacts the DG required action completion time extension.

SY-02 The failure of the time delay relay associated with the steam admission valves to the TD AFW pump turbines is not included in the CCPRA. The relay failure could result in the overspeed failure of the TD AFW pump.

CCNPP Response: This is a non-conservative fault-tree error. Its incorporation is expected to result in a small increase in the auto-start turbine-driven AFW pump failure likelihood. This increase will result in a very small increase, approximately a 0.25 percent change, in the calculated CDF. Issue Report IR3-070-507 has been initiated to capture this issue.

Required Action Completion Time Extension Impact: The small impact of this error is not expected to change the conclusion of this required action completion time extension submittal.

SY-08 On loss of component cooling, the CCPRA credits the possibility of failure of the RCP motor before RCP seal failure in order to prevent a seal failure. If the motor is stopped by failure, the likelihood of seal failure is significantly reduced.

CCNPP Response: The appropriateness of crediting the failure of the RCP motor was previously identified as an open item (CRMP 138). Crediting the failure of the RCP motor was instituted after talking with a PRA practitioner from another plant many years ago. This position was also supported by a system engineer (this has been bases captured). However, it appears that this practice is now an outlier. This will be re-assessed when the new RCP model is implemented during the next update. Due to EOP improvements, elimination of the credit for the failure of the RCP motor is believed to have a minimal impact on the calculated CDF.

Required Action Completion Time Extension Impact: A sensitivity analysis is included to understand how this issue impacts the DG required action completion time extension.

DA-01 NUREG/CR-5497 provides the latest industry data source for common cause failure events. The CCPRA has adopted this data for a very limited scope of components (MSSVs and the PORVs).

CCNPP Response: The use of NUREG/CR-5497 data will be increased in future updates of the PRA. This is captured by a new open item (CRMP 426). Consistent with our configuration control process (EN-1-330) no Issue Report has been initiated since this is an update to more recent data.

Required Action Completion Time Extension Impact:

The following common cause factors from NUREG/CR-5497 have been incorporated into the CCPRA:

- DGs – Fail to Start, Fail to Run
- PORVs – Fail to Open, Fail to Close, and Fail to Remain Close
- Main Steam Safety Valves – Fail to Open, Fail to Close
- Low and High Pressure Safety Injection MOVs – Fail to Open

A complete comparison of the remaining common cause factors was performed. The following significant deltas were found:

1. Battery Failure Rates

   The CCNPP Beta Factors were more conservative than the NUREG. However, the Gamma and Delta Factors were non-conservative compared with the NUREG.

2. 4kV Breakers

   CCPRA Common Cause Factors for "Fail-to-Close" are non-conservative when compared with the NUREG.

3. Reactor Trip Breakers

   CCPRA Common Cause Factors for fail-to-open are non-conservative when compared with the NUREG.

4. Emergency Service Water Pumps (Service Water, Component Cooling Water, Saltwater)

   CCPRA "Fail-to-Run" Beta factors are significantly more conservative than the NUREG.

5. AFW and HPSI Check Valves

   CCPRA Beta Factors for fail-to-open are less conservative than the NUREG.

6. PORV Block Valves

   CCPRA has much more conservative values for the PORV Block valves than the NUREG.

The cases where the CCPRA was non-conservative were checked for impact on the DG Required Action Completion Time Extension. It was found that the Battery, Reactor Trip Breakers, and Check Valves noted do not significantly impact the DG Required Action Completion Time Extension risk. The 4kV Breaker fail-to-close mode has the potential for an impact. A sensitivity study was performed that found this impact to be small.

HR-01 The CCPRA quantified the pre-initiator human actions using a failure rate based on NUREG/CR-1278. The values were treated as mean values. However, the values in NUREG/CR-1278 are median values.

CCNPP Response: This is a non-conservative error. Its impact is very small. Issue Report IR3-070-508 was initiated to capture this issue.

Required Action Completion Time Extension Impact: The impact of this issue is very small and does not change the conclusions of the required action completion time extension submittal.

HR-03 There are several human actions that use Unit-2 to help mitigate Unit-1. No example of an analysis could be found that considered the impact of the operating status (operation, outage, and startup) on the human actions.

CCNPP Response: A review of impact of the opposite unit operating status on the human actions has not been performed. This is captured by a new open item (CRMP 429). Issue Report IR3-070-509 has been initiated to capture this issue.

Required Action Completion Time Extension Impact: A review of all the human actions was performed for this submittal to determine if changes are necessary to address this issue. No changes were identified.

6.1.11.3 Changes Between the IPE/IPEEE and Revision 0 (Peer Reviewed)

Many changes have been made to the CCPRA since the IPE and IPEEE submittals. The CCPRA Revision 0 model was peer reviewed in November 2001. The Revision 0 model was approximately the fourth update of the Calvert Cliffs PRA since the IPE Summary Report and is the first model to be controlled by a formal configuration control program. See the below table for a summary of the CCPRA development history.

Table 21
CCPRA Development History

Model	Unit-1 Description	Unit-2 Description	Date
Revision 1	Internal and External Events	Internal and External Events – development based on over 200 identified changes between Unit-1 and 2. Unit-2 cable routed generally assumed to be the same as Unit-1 for fire impact.	10/2002
Revision 0	Internal and External Events	Unique aspects of External Events on Unit-2 were deferred to Revision 1.	5/2002
Revision 0	Internal Events – This updated model was used for the implementation of the revised Maintenance Rule (a)4 requirements. This is the first model to be controlled by a formal configuration control program.	Internal Events only – development based on modeling major changes between the Units.	10/2001
Revision A	Interim Update	Not Assessed.	3/99
IPEEE + Update 2	First Internal and External Models	Differences were assessed and qualitatively addressed.	2/98
IPEEE	Fire, Seismic and High Wind PRA	Differences were assessed and qualitatively addressed.	8/97
Update 2	Updated internal events model for IPEEE	Not Assessed.	8/97
Update 1	First Update	Not Assessed.	5/94
IPE	Internal Events and Level 2	Differences were assessed and qualitatively addressed.	12/93

6.1.11.4 Changes Between Revision 0 (Internal Events Peer Reviewed) and Revision 1

There are a number of changes between the Revision 0 model and the Revision 1 model. The majority of the substantive internal events changes are directly a result of the internal events peer review. The internal Revision 0 CDF is 4.0E-5. The internal events Revision 1 CDF is 3.4E-5. The change in the modeling of a multiple tube steam generator tube rupture accounts for the majority of this decrease. (In Revision 0 the multiple-tube steam generator tube rupture has a contribution of approximately 5.0E-6). The remaining internal events changes are focused on the modeling of the DGs. These changes focused on ensuring the accuracy of the DG modeling. Improvements included using the most recent common cause factors, the most recent failure data, and fully crediting the 0C DG. These changes caused both increases and decreases in the risk of removing a DG from service. Here are some of the more substantial changes between the Revision 0 and the Revision 1 model:

- **Improved Human Action Methodology**

  The current CCPRA human action methodology was refined to address several identified issues. The base methodology remains the same. These issues included:

  ✓ *Better Treatment of Peer Checking*

  The Revision 0 model did not explicitly address peer checking. The new methodology adds additional performance shaping factors to account for the benefit of effective peer checking. This is especially important for actions that have a large amount of implementation time and have many opportunities to recover.

  ✓ *Better Treatment of Degradation due to entry into the Functional Recovery EOP and for fire conditions*

  The Revision 0 model used a fixed degradation value for entry into the more complicated functional recovery EOP. Revision 0 also used a set of standard degradations for fire related actions. The new approach explicitly determines the degradation through operator interviews. Each performance-shaping factor is interviewed for the base value and for various degradation values. This approach more appropriately determines the degree of degradation and ensures that the various degradation values are consistent.

  ✓ *Clarified Performance Shaping Factors*

  The performance shaping questions were clarified to ensure more consistent understanding and results. An operation crew as opposed to individual focus is now emphasized.

  The above changes were applied to about a dozen base human actions with associated Auxiliary Feedwater Control, 0C DG alignment, 0C DG fuel oil make-up, and long-term inventory control in the CCPRA Revision 1 model. This represents about ten percent of the actions included in the CCPRA. Other actions will be updated to the newer methodology in future updates.

- **Added Undervoltage (UV) Actuation Top Events**

  The undervoltage function was previously included in the DG top events to account for the impact of the failure to load shed. However, when the 0C DG is aligned to a 4kV ESF bus, the UV signal for that bus is manually actuated in order to shed and reload the bus. Therefore, the load-shed function not only impacts the dedicated DG, but also the success likelihood of the 0C DG. Making the UV function into separate functions (Top Events UA, UB, UC, and UD) allows the model to better account for this dependency.

- **Increased Credit for 0C DG**

  The CCPRA Revision 0 model used 0C DG for providing power to the battery chargers and powering the motor-driven AFW pumps. The 0C DG must be aligned within forty-five minutes to support AFW (Top Event GK) and within two hours to support the battery chargers (considered within Top Event GJ in Revision 0).

  The CCPRA Revision 1 model adds a twenty-minute (Top Event GS) and forty-five minute recovery (Top Event GK) to support once-through-core-cooling and Auxiliary Feedwater respectively.

  CCPRA Revision 1 also credits late 0C DG alignment for late failures of the Service Water-cooled Fairbanks Morse DGs. This change enables the 0C DG to support the motor-driven AFW pump and battery chargers when the FM DGs fail due to Service Water failures.

CCPRA Revision 1 also includes an improved analysis of the 0C DG fuel oil day tank (FODT) which has an eight-hour capacity. This facilitated lowering the 0C DG failure rate as the makeup component failure probabilities could be removed for LOOP events that are eight hours or less.

No credit was included in the CCPRA Revision 0 model for using the 0C DG to recover 4kV Bus 11 on the spurious ESFAS actuation as an initiating event (Initiating Event IESF). Initiating Event IESF is modeled as causing a spurious and temporary actuation of ESFAS Channel A. One of the impacts of this actuation is to load shed 4kV Bus 11. In Revision 0, DG 1A was the only DG credited. In Revision 1, both DG 1A and DG 0C are credited for recovery of 4kV Bus 11 following IESF.

- <u>Improved Diesel Generator Modeling</u>

  The CCPRA Revision 1 model has DG maintenance alignments addressed by separate top events (Top Events G1, G2, G3, G4 and G5). Previously, the maintenance alignments were included within the diesel generator top events. This old approach made it difficult to account for the mutual exclusivity of the maintenance and the operational practice of pre-aligning the 0C DG during DG maintenance. This change is based on the assumption that no more than one DG will be OOS at the same time for diesel maintenance or due to Salt Water Header unavailability (except for 1A DG, which does not require SW cooling supports). See Assumptions Section for a discussion on this issue.

  The CCPRA Revision 1 also added a common cause linkage (Top Event GC) between the SACM and Fairbanks Morse diesel generators. Since these diesel generators are quite diverse, this new common cause relationship represents a weak link between these diverse diesels. Included in the common cause considerations are the 4kV feeder breakers and the relays associated with the ESFAS undervoltage actuation signals. See the Assumption Section for the approach to modeling the failure of load-shed relays. Although very unlikely, this change explicitly accounts for common cause across the highly diverse SACM and Fairbanks Morse diesel generators.

- <u>Incorporated PORV Logic Modification</u>

  This modification prevents the failure of two 120VAC vital busses from causing a spurious opening of the PORVs and removes the 125VDC dependency to open the PORV for once-through-core-cooling (OTCC). The modification also added a key-locked switch to the control panel to enable the initiating of OTCC. Top Event PO was added as a plant-condition flag to represent the installation status of this modification. The modification is installed in Unit-1 (2002 Refueling Outage) and Unit-2 (2003 Refueling Outage). A second PORV top event (Top Event PP) was also added to better address the status of whether both PORVs are open to support pressure relief or decay heat removal.

- <u>Improved Multiple SGTR Modeling</u>

  Improved multiple SGTR modeling per the recommendation of the Peer Review team. As long as the steam generators are isolable (Top Event SQ), multiple tube ruptures (Top Event WS) are considered recoverable. This improvement addresses the peer review F&O "AS-01." See Section 6.1.11.2 Peer Review "B" Level Fact and Observations for a discussion and resolution of this issue.

- <u>Improved Containment Modeling</u>

  Restructured top events and initiating events such that containment breaches greater than two inches are considered "large." This change impacts penetrations less than two inches (Top Event SH), greater than two inches (Top Event SI), the Hydrogen Purge line (Top Event SG) and the containment sump line (Top Event SR). The definition of LOCA initiating events less than two inches (IVV1) and greater than two inches (IVV2) also changed. These changes make the CCPRA LERF modeling more consistent with industry practice.

- **Improved AFW Flow Control and Make-up Modeling**

  The CCPRA Revision 0 model addressed all AFW flow control conditions using a half dozen split fractions. The human actions used to represent these conditions addressed both early and late flow control conditions, local and remote control and the status of indication. The approach to modeling the AFW flow control was revised to better address the impact of these various conditions. This approach allowed for the better matching of the interviewed action with the accident scenario. The new human action methodology was used for these actions.

  The CCPRA Revision 1 model also improves the link between steam generator overfill recovery actions and the AFW flow path top event (Top Event F1). If the operator fails to align AFW Pump 23 to Unit-1 (Top Event OB) or to start AFW Pump 13 (Top Event FH) then it is unlikely that he will be able to perform the complicated actions involved with recovering from a steam generator overfill.

- **Improved Long-Term Condensate Functionality**

  The human actions associated with long-term condensate inventory (Top Event F3) were re-interviewed and restructured. The interview process discovered a built-in peer checking process for dual unit trips, like LOOPs, in that both units monitor the shared condensate storage tank. Other insights were also gained during the interview process. This resulted in a general improvement in the modeling of the maintenance of long-term availability.

- **Improved ESFAS Actuation Modeling**

  ESFAS actuation channel 15V/28V power supply tops (Top Events J1 and J2) were added. These power supplies were previously modeled within each ESFAS model top event. The new top events allow the model to effectively account for the potential of a common mode failure of all ESFAS top events.

Improved HPSI Pump Modeling

Top Events HD, HE & HJ now represent the Human Action to throttle HPSI flow (for 11, 12 and 13 HPSI pumps). Failure to throttle results in HPSI Pump failure after the start of recirculation. In Revision 0, the failure of these human actions was considered a short-term failure of the HPSI pumps. In Revision 1, this is considered to fail the HPSI pumps only after the start of re-circulation, which occurs later in the accident. This is primarily a Level 2 impact.

- **Improved Modeling of the 4kV Bus Alternate Feed Modeling**

  The CCPRA Revision 0 model contains an operator action to align the alternate feeder breakers from the other 13kV bus, if available. The Revision 0 model conservatively failed this action for both units if the Unit-1 4kV transformers failed. Revision 1 represents these functions using two separate top events, one for Unit-1 (Top Event H5) and one for Unit-2 (Top Event H6). As both the Unit 1 and Unit 2 Plant Models are impacted by the status of its own and the opposite unit 4kV busses, Top Events H5 and H6 are modeled in the Unit 1 Plant Model and the Unit 2 Plant Model.

- **Updated High Wind Model**

  On April 28th, 2002 a significant tornado struck Southern Maryland. Weather experts determined that the tornado briefly reached F4 in La Plata, Maryland. The tornado continued across Charles and Calvert Counties passing north of CCNPP. The high wind analysis did not consider the probability of F4 or F5 tornadoes. The High Wind initiating frequencies were updated to reflect the recent tornado experience. In addition, the model structure was changed to reflect the impact associated with a larger footprint tornado.

- <u>Updated Fire Model</u>

  Unit-1 Fire Model, Revision 1 is an update and refinement of the IPEEE Fire Model. Fire Model Revision 1, like the IPEEE, assesses the risk contribution and significance of fire initiated events to the total plant risk. The split fraction values used in the Fire model are based on five Master Frequency Files (MFFs) each adjusted/specific to areas impacted by fire.

  Improvements to the Revision 1 Fire Model include:

  - Incorporation of the internal events Plant Model Revision 1 changes.

  - Incorporation of an improved human action methodology for many important human actions. The new Revision 1 human action methodology is an improvement over Revision 0 in that smoke impacts are directly assessed during the operator interview process.

  - Improved modeling for AOP-09A, Control Room Evacuation and Safe Shutdown due to a Severe Control Room Fire. A detailed review of the Control Room abandonment procedure was performed that resulted in many structural improvements in the model. The scope of AFW flow actions (Top Event FW) and electrical alignments (Top Event VB) changed as a result. The human actions to trip with a "non-trip" fire (Top Event FU) and aligning DG 1A or offsite power when DG 0C is unavailable (Top Event FV) were added to the fire model.

  - Updated the fire ignition frequency impacts for the Control Room, Cable Spreading Rooms, Switchgear Rooms, Turbine Building, and Yard.

  - Improved the modeling of turbine building fires. This included the refinement of fire impacts, the consideration of the newly install Condenser Pit Fire Sprinkler System and the consideration of the modified Control Room ventilation system that is now in a permanent re-circulation mode.

6.1.11.5 CCNPP Unit-2 Revision 1 Model

Background

Construction began on CCNPP, Units 1 and 2 in July 1969. The Nuclear Steam Supply Systems (NSSS) for both units are supplied by Combustion Engineering. The NSSS encompasses the Reactor Vessel, Steam Generators, Reactor Coolant Pumps, Pressurizer and Emergency Core Cooling Systems. Bechtel Corporation designed the balance-of-plant systems and was responsible for overall construction. Unit-1 began commercial operation in May 1975 and Unit-2 on April 1977.

The Main Turbine Generator and the Steam Generator Feed Pumps for each unit are supplied by different vendors, General Electric Company for Unit-1 and Westinghouse Electric Corporation for Unit-2. Although these components are different, they have almost exactly the same technical parameters and accomplish the same function.

A key difference between the units occurred with the addition of two new diesel generators. The 1A DG and 0C DG, added in the late 1990's, are both air-cooled diesel generators. The three other site diesels are Service Water (SRW) cooled. DG 1A supports a Unit-1 bus while DG 0C is a station blackout (SBO) diesel that can be aligned to any Unit-1 or Unit-2 4kV ESF bus. This configuration resulted in Unit-1 having one SRW cooled DG and one air-cooled DG. Unit-2 has two SRW cooled DGs.

PRA Model

The CCNPP Unit-2 Revision 1 model is the first Unit-2 model that quantifies both internal and external events. Note that the difference in the DG configuration, including the addition of the 0C DG, occurred after the IPE Submittal.

The Unit-2 model starts with the Unit-1 model. Differences between the units were then identified and incorporated as changes to the Unit-1 event-tree rules to create the Unit-2 event-tree rules. Over two hundred differences are modeled between the Unit-1 and Unit-2 models. A simplified approach was used in the development of the Unit-2 fire model in that cable routing between the units was generally considered the same.

Two significant differences between the units are described below:

- Diesel Generator Configuration

  Although the Unit-1 and Unit-2 models contain the functions of all four DGs and the 0C DG, the alignment of these diesels from the individual unit perspective is different. Therefore, the Unit-2 model reflects that the dedicated DGs are service-water dependent. The Unit-1 model has one air-cooled DG (1A DG) and one SRW dependent DG.

- Turbine Building Service Water Configuration

  Both units have an interface between the safety-related SRW headers located in the Auxiliary Building and the non-safety-related SRW sub-system located in the Turbine Building (Turbine Building SRW). In both units, the Auxiliary Building headers supply cooling to the Turbine Building loads. Two redundant sets of isolation valves are able to isolate the Turbine Building loads from the safety-related SRW headers on a SIAS condition.

  In Unit-1, the two SRW Headers remain separate after entering the Turbine Building until just prior to returning to the Auxiliary Building. The instrument air compressors are the critical components cooled by SRW Header 11. SRW Header 12 provides cooling to the steam generator feeder pump and condensate booster pump lube oil coolers. Therefore, the loss of SRW Header 11 will result in the loss of the instrument air compressors.

  The Unit-2 SRW Headers combine into a common header immediately after entering the Turbine Building. A loss of a single SRW header does not result in the loss of the instrument air compressors.

6.1.11.6 Other Relevant CCPRA Open Items

The CCPRA configuration is procedurally controlled by EN-1-330, Probabilistic Risk Assessment Configuration Control Procedure. Plant changes are monitored for impact on the PRA. Areas for modeling improvement are also captured. Issues requiring action are entered into the CCPRA Configuration Risk Management Program (CRMP) database as a CRMP Issue. Issues are prioritized as to their potential impact on the calculated risk as follows:

A	Potential changes of five percent or more to CDF or LERF
B	Potential changes of one percent or more to CDF or LERF
C	Potential changes that enhance or have limited sequence impact
D	Documentation issues

The open CRMP Issues were reviewed to identify those that could have a potential impact on the proposed change to the diesel required action completion time extension. These issues are discussed below.

"A" CRMP Issues

CRMP 138 **Re-evaluate the treatment of RCP Seal LOCA – Incorporate new CEOG Seal LOCA Model when developed.**

Required Action Completion Time Extension Impact: As noted in the discussion on F&O AS-04 from the Peer Review, a sensitivity analysis is included to understand how this issue impacts the DG required action completion time extension.

CRMP 139 **Develop an improved methodology for fire human actions.**

This issue addresses the concern that the increases in human action failure rates are not consistent or intuitive as they could be. Generally the easier actions with low failure rates are being increased more dramatically than harder actions with high failure rates.

Required Action Completion Time Extension Impact: A new human action methodology was developed to address this concern. The key diesel alignment split fractions were quantified with this new methodology. All AFW flow control human actions, which are very significant in core damage sequences, are also quantified with this improved methodology.

CRMP 210 **Add an unavailability alignment for an ESFAS Cabinet being de-energized.**

If an ESFAS Sensor Cabinet is de-energized all ESFAS Channels go to a 1 of 3 condition. Any spurious actuation in any one of the remaining three channels will cause a spurious ESFAS actuation. Failure of any power supports for the remaining channels will cause all ESFAS functions to spuriously actuate, including UV actuation.

Required Action Completion Time Extension Impact: The ESFAS channels are powered from 120VAC Panels which are in-turn powered by 125 VDC Busses. The interface between this issue and the DGs is that during a LOOP the DGs provide long-term power to the 125 VDC busses. For a spurious ESFAS actuation to occur power would need to be lost to one of the remaining sensors. This would take the failure of 3 DGs. For example, the 1A DG, the 2A DG, and the 0C DG being lost would cause the 'A' facility sensors to trip once the 125VDC batteries deplete. For this issue to cause a problem, these events must occur:

- off-site power must be lost to the same facility on both Unit 1 and Unit 2 for a duration longer than the battery life on the remaining ESFAS sensors,
- three DGs must fail or be out-of-service,
- a ESFAS channel must be OOS, and
- the ESFAS channel is not restored prior to battery depletion.

Given the likelihood of these events and the rarity of an ESFAS sensor channel OOS, this issue is not considered to affect the DG required action completion time conclusions.

"B" CRMP Issues

CRMP 14 **Implement improvements in the CCPRA human action methodology.**

The following issues were identified associated with CCPRA human action methodology:
1. There is a large difference between operator estimate and calculated human action values.

2. The methodology does not clearly identify the entire Control Room team as being considered for each action.

Required Action Completion Time Extension Impact: As noted for CRMP 139 above, actions associated with aligning DG 0C to a safety related bus have been re-interviewed as well as those associated with controlling AFW flow.

CRMP 17 **Re-assess the value for PORV failure to CLOSE to ensure testing limitation are accounted for in the failure rate.**

This issue addresses the concern that the tests used as plant experience in the Bayesian Update may not adequately test the actual function of the PORV.

Required Action Completion Time Extension Impact: A sensitivity study was performed that tripled PORV fail-to-close failure rate. The result did not significantly change the CDF impact of the proposed DG required action completion time changes.

CRMP 18 **Re-assess the value for PORV failure to OPEN due to concern on the Bayesian update on the generic failure rate.**

Required Action Completion Time Extension Impact: The PORV fail-to-open top events are also not significant contributors with regards to the CDF impact of the DG required action completion time changes.

CRMP 78 **Update the Level 2 analysis.**

There is potential for improvements in the existing Level 2 analysis as this is still based on the IPE analysis.

Required Action Completion Time Extension Impact: Revisions to the Level 2 analysis are not expected to significantly change the fraction of LERF sequences when compared to CDF sequences. Most improvements will likely result in the refinement of some of the bounding analysis that is currently used. Some improvements have been made to the Revision 1 CCPRA model to improve the LERF binning.

CRMP 126 **Based on new SWGR Heat-up Calculation consider Temperature Acceleration on the SWGR Room Components**

Required Action Completion Time Extension Impact: SWGR HVAC is required when both 4kV busses (one SR and one NSR) are energized in the same room. During a LOOP, the NSR busses de-energize and SWGR ventilation is not required. As a result, the temperature acceleration caused by a loss of SWGR ventilation is not very important to the DG required action completion time extension calculations.

CRMP 182 **EOP Revisions need to be incorporated into Plant Model**

Required Action Completion Time Extension Impact: All human actions relevant to 0C DG have been re-interviewed as well as all AFW Flow Control actions.

CRMP 279 **Improve the modeling of the failure of SRW during a LOOP to allow a late SSSA due to the loss of SRW induced DG Failure.**

The potential for Service Water or Saltwater failures to cause a Spurious Safety System Actuation, by failing the Fairbanks Morse DGs, is not considered in the plant model.

Required Action Completion Time Extension Impact A sensitivity was performed to determine the impact on the DG required action completion time revision. Saltwater and Service Water failure rates were added to the DGs and there was no significant change to the overall risk due to the expected DG unavailabilities.

CRMP 286 Investigate improving the HPSI injection header MOV throttling success criteria.

Currently it is assumed that failing to throttle the HPSI Loop MOVs will cause failure of the pumps on RAS actuation. This may be overly conservative.

Required Action Completion Time Extension Impact: A review of sequences shows that assuming that the HPSI Pumps would not fail, if the LOOP MOVs were not throttled on RAS, would not be a significant change in the calculated impacts of this required action completion time extension. Unavailability of the DGs is not significant in HPSI failure sequences.

CRMP 342 Steam Generator Blowdown is not accounted for in the timing bases for operator actions used to recover decay-heat removal system failures.

The timing of loss of feedwater recovery actions may be impacted by this change.

Required Action Completion Time Extension Impact: The timing of DG 0C alignment actions could be impacted here. Top event GK models the alignment of 0C DG in time to recover a loss of all feedwater with AFW within 45 minutes. To model the impact of less time to align DG 0C, all GK split fractions were doubled. This did not significantly impact the risk due to the expected changed in DG unavailability.

CRMP 438 Evaluate the need for increasing the LOCA Sump Failure Likelihood due to insulation induced blockage.

Required Action Completion Time Extension Impact: Injection sequences with a DG unavailable are not significant. Increasing the Sump blockage probability is not expected to cause a significant increase in risks associated with the DG required action completion time.

CRMP 530 Formalize the Basis for the Fraction of AFW Underfill given a Loss of AFW Flow Control

Required Action Completion Time Extension Impact: The probability that operations will underfill the Steam Generators, given flow control is failed and all supports are available, is 20%. Doubling all UQ values will only cause an increase in the overall risk impact of the DG required action completion time extension by 2E-08 per year.

6.1.11.7 PRA Software Control

The primary event-tree quantification computer program, RISKMAN Version 2.0 for Windows, used to support the CCPRA is classified as safety-related. RISKMAN Version 5.0 for Windows, also classified as safety-related, was used for some fault-tree re-quantification.

Other post-processing software programs are classified as safety-related. Two in-house programs are used: the Minimizer and the QSS Evaluator.

Minimizer Version Z
The MINIMIZER removes guaranteed failed top events and the success top events from the sequences and Boolean reduces the number of sequences. This minimization has the advantage of reducing the total number of sequences, reducing their complexity and improving the amount of risk contribution captured for a given truncation level. The results resemble cutsets in that each accident sequence contains only the initiating event and the split fractions that independently failed. The output of the Minimizer is a set of core damage cutsets and a set of LERF cutsets. These files are the input to the QSS Evaluator.

The MINIMIZER also automates many of the steps used in determining the proper truncation limit.

This software is classified safety-related. Formal verification and validation of the changes made to enable this analysis, the ability to handle multiple models (internal events, fire, siesmic, etc.) was in progress at the time of this submittal.

QSS Evaluator Version P
The QSS Evaluator is a software tool that quantifies the CCPRA model using a set of minimized sequences. Its primary function is for the calculation of Maintenance Rule (a)4 risk assessment. The QSS Evaluator was used for the risk assessment of this proposed amendment to determine the change in the risk metrics resulting from implementation of the proposed DG required action completion time extension and for the included sesnitivity studies.

This software is classified as safety-related. Formal verification and validation has been completed and documented consistent with the site processes and procedures.

6.2 Tier 2, Avoidance of Risk-Significant Plant Conditions

Tier 2 is an identification of potentially high-risk configurations that could exist if equipment in addition to that associated with the TS change is taken out of service concurrently, or other risk significant operational factors such as concurrent system or equipment testing are involved. The objective of Tier 2 is to ensure that appropriate restrictions are placed on dominant risk significant configurations that would be relevant to the proposed TS change.

6.2.1 Station Blackout Diesel (0C DG)

If the Station Blackout Diesel (0C DG) is out of service at the same time a DG is out of service, the DG required action completion time will remain seventy-two hours.

6.2.2 Unit-to-Unit Interaction

Only one DG between the two units can be taken out-of-service for planned entry into the extended required action completion time. If multiple DGs are out-of-service, one on each unit, then the seventy-two hour required action completion time applies. If multiple DGs are out-of-service on a single unit then TS 3.0.3 applies.

6.2.3 Switchyard Maintenance

Existing operator instructions (OI) specify the following precautions prior to taking out of service a safety-related DG:

- Determine whether other maintenance is in progress or planned that will reduce the reliability of off-site power supplies.
- The Shift Manager determines how to minimize both the time that the DG is out of service and the time that off-site power supplies are at reduced reliability.

In addition, the existing on-line risk assessment process (refer to Tier 3, Configuration Risk Management, below), would measure the overall plant risk of diesel unavailability concurrently with maintenance activities in the switchyard. This risk is managed in accordance with paragraph (a)(4) of 10 CFR 50.65.

6.2.4 Grid Availability (High Winds)

High winds (hurricanes and tornadoes) could cause damage to the grid and could result in a plant trip in conjunction with a loss of offsite power. The CCNPP Emergency Response Plan specifies actions to take in severe weather conditions. If a tornado watch, tornado warning, hurricane watch, or hurricane warning are predicted or exists for CCNPP or any of the 500KV line right-of-ways, then the following Tier 2 restrictions are implemented:

- Ensure that the diesel generators are available for service.
- If a diesel generator is not available, expedite maintenance to ensure that the equipment becomes available.

In addition, the existing on-line risk assessment qualitatively assesses the impact of predicted severe weather against planned plant maintenance configurations. This risk is managed in accordance with paragraph (a)(4) of 10 CFR 50.65.

6.3 Tier 3, Configuration Risk Management

Tier 3 is the development of a proceduralized program, which ensures the risk impact of out-of-service equipment is appropriately evaluated prior to performing a maintenance activity. The program applies to technical specification structures, systems or components for which a risk-informed required action completion time has been granted. 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 and is described in RG 1.77 as the Configuration Risk Management Program (CRMP). The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under Tier 2 that will be encountered over extended periods of plant operation.

Integrated on-line risk assessment has been in use at CCNPP since mid 1990s. Due to a revision to the Maintenance Rule, 10 CFR 50.65 (a)4, the process was updated in November 2000 to reflect the guidance in NUMARC 93-01 Revision 3.

The CCNPP on-line risk assessment process helps to ensure that the decrease in plant safety for voluntary entry into a limiting condition for operation action statement is small and is acceptable for the period of the maintenance or testing activity. It also helps to ensure that the removal from service of safety systems and important non-safety equipment and the general impact of maintenance and testing is minimized. This assurance is applicable for all plant configurations and is specifically applicable to the entry into the proposed extended DG required action completion time.

Consistent with RG 1.177, the following program elements are described below:

6.3.1 On-line Risk Assessment – PRA Scope and Control
6.3.2 On-line Risk Assessment – Tools
6.3.3 On-line Risk Assessment – Process
6.3.4 On-line Risk Assessment – Level 2
6.3.5 On-line Risk Assessment – External Events

The elements of the current process are described below. Details of this process may change over time. However, the fundamentals of performing of an integrated risk assessment using probabilistic risk techniques that meets the Maintenance Rule (a)4 requirements will not.

6.3.1 On-line Risk Assessment – PRA Scope and Control

This sub-section addresses the scope and control of the PRA used to support on-line risk assessment.

6.3.1.1 PRA Scope

The CCPRA used for on-line risk assessment is a Level 1 and 2, at-power, internal events PRA. The on-line risk assessment model is derived from the current revision of the PRA. The model is modified to remove the impact of planned maintenance on initiating events and mitigating events. In addition, the impact of the plant availability factor is removed, that is, initiating event frequencies are increased since the plant operating mode (at-power) is known. The PRA is used to assess risk in Modes 1, 2, and 3.

Lower modes of operation (Modes 4, 5, and 6) are assessed consistent with the INPO 89-017 Revision 1, Guidelines for Management of Planned Outages at Nuclear Power stations and NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management.

Although an external events PRA that addresses fire, seismic and high winds was used for the risk assessment supporting this proposed license amendment, the on-line risk assessment of external events is qualitatively assessed.

6.3.1.2 PRA Configuration Control

The CCPRA configuration is procedurally controlled by EN-1-330, Probabilistic Risk Assessment Configuration Control Procedure. This procedure provides the control and processes for maintaining the CCPRA consistent with the as-operated, as-built plant.

Plant changes are monitored for impact on the PRA. Issues requiring action are entered into the CCPRA Configuration Risk Management Program (CRMP) database as a CRMP Issue. These issues are prioritized in accordance with their significance for implementation into future PRA updates. Significant CRMP Issues that are the result of errors are entered into the site corrective action program.

Routine training ensures that current users of the PRA, including the on-line risk assessment analysts are aware of all significant open issues.

Issues that potentially impact the on-line assessment tools are procedurally identified and addressed.

6.3.2 On-line Risk Assessment – Tools

This sub-section describes the on-line risk assessment tools and their controls.

6.3.2.1 Description of On-line Risk Assessment Tools

The Calvert Cliffs Quarterly System Schedule (QSS) on-line risk assessment process uses a suite of in-house developed software to determine the risk configuration of the plant. These software tools are:

QSS Communicator	This software application imports data (maintenance activities for a given week) from the maintenance scheduling software and facilitates the processing of this information by the Work Week Coordinator with regard to scope and equipment impact. A companion software application called the Outage Communicator aids in capturing the outage activities that could impact the opposite unit.
QSS Converter	This software application uses the output from the Communicator and aids in associating the impacted plant function to the appropriate PRA impact (if previously developed) or supports the development of a new impact. Qualified PRA analysts perform this activity.

QSS Evaluator	This software application uses the output of the Converter and the output from the CCPRA (solved accident cutsets) to determine the integrated risk impact. Note: Although the CCPRA is based on RISKMAN software that produces accident sequences, these sequences are post-processed to have characteristics like cutsets.

6.3.2.2 Control of On-line Risk Assessment Tools

PRA Model Input

The on-line risk assessment model used, as input into the QSS Evaluator is a zero maintenance unavailability version of the base PRA model. Open items against the base PRA model are assessed for impact of the on-line risk assessment process. The PRA analyst addresses any applicable identified items during the on-line risk assessment evaluation process. This process is proceduralized in EN-1-334, Probabilistic Risk Assessment of Maintenance Activities.

Tool Software Control

The software suite used for the on-line risk assessment process has been developed using verification and validation techniques to ensure high confidence in its capability and results.

6.3.3 On-line Risk Assessment – Process

The on-line risk assessment process is controlled by a site procedure, NO-1-117, Integrated Risk Management, and a unit level procedure, EN-1-334, Probabilistic Risk Assessment of Maintenance Activities. The site procedure establishes the overall administrative controls, responsibilities and duties for the direction, control and oversight of risk significant activities at CCNPP. The unit level procedure identifies the controls and processes used by the PRA analysts to support the integrated risk assessment process.

The integrated risk management process uses both deterministic and probabilistic tools to identify and control risk.

6.3.3.1 Qualitative Risk Assessment

Plant personnel assess the following risks during the planning process for each planned maintenance activity:

- Nuclear Safety
- Industrial Safety
- Environmental Safety
- Corporate Safety

Note: Radiological Safety is assessed through a separate process.

This risk assessment is performed using a series of checklist. Each risk area is evaluated as HIGH, MEDIUM or LOW. Nuclear Safety HIGH and MEDIUM activities are included in the integrated probabilistic risk assessment. By including these activities, the process has an effective means of capturing potentially risk significant activities, especially trip sensitive activities that may not have been directly in the scope of the PRA.

6.3.3.2 Integrated Probabilistic Risk Assessment – Planned LCO Entry

An integrated risk assessment is performed two weeks prior to execution of the maintenance activity. Consistent with RG 1.160, Revision 2, the scope of the CCNPP on-line risk assessment process includes all structures, systems and components (SSCs) modeled in the plant PRA. No additional at-power high safety significant SSCs were identified. The process considers the following activities as part of the scope:

- **All PRA Scope Functions**

  A Maintenance Rule Risk Assessment Guideline is maintained to aid in the determination of the scope of the Calvert Cliffs risk assessment process. This guideline is controlled by the NO-1-117, Integrated Risk Assessment Procedure. The guideline lists the plant functional equipment group (FEG) identifiers that are within scope of the PRA. FEGs identify groups of equipment that perform like functions to help optimize the scheduling process. FEGs are similar to top events. Several maintenance activities are often performed on different components (for example, a pump and its associated breaker) related to the FEG that is taken out of service. Work activities are coded with the FEG identifier in the planning process and are electronically transferred into the QSS Communicator as part of the risk assessment scope.

  The tying of the FEG to PRA scope allows for a transparent interaction between the work scheduled and the work assessed.

- **Nuclear Safety HIGH and MEDIUM**

  Individual maintenance activities that have been assessed as Nuclear Safety HIGH or MEDIUM (deterministic risk assessment) are included in the scope of the integrated risk assessment. These activities are coded in the planning process and electronically transferred into the QSS Communicator as part of the risk assessment scope.

- **Testing**

  Activities associated with surveillance and other periodic testing are electronically transferred into the QSS Communicator.

- **Other**

  Doors, risk significant locations, and other activities are also included in the evaluation process.

  The Work Week Coordinator processes this information using the QSS Communicator by reviewing the maintenance activities, determining the FEG state (whether the FEG is available, not available, valve locked open, etc.) and screening non-intrusive maintenance. Once completed, he transfers this information to the qualified PRA analyst. The PRA analyst uses the QSS Converter to facilitate the determination of the impact of each maintenance activity on the CCPRA. The analyst develops impact macros that convert the activity to the appropriate impact on initiating events and split fractions. If the impact had been previously determined, the QSS Converter will automatically assign the appropriate impact.

All activities are either assigned a macro or screened. Cross unit impacts are also determined during this process, including the risk impact of outage maintenance activities on the opposite, on-line unit. Once all activities are dispositioned, the PRA analyst evaluates the integrated impact using the QSS Evaluator. The Evaluator addresses the impacts on Unit-1 and Unit-2 as determined by the PRA analyst. The evaluation typically considers a preventive or corrective maintenance activity to last twenty- four hours in order to allow scheduling flexibility within any given day. Tests are typically assessed on a 12-hour shift basis. Some risk activities may be assessed and managed on shorter time increments.

The following risk metrics and action thresholds are used in this process:

Table 22
CCNPP On-line Risk Thresholds

Metric	Threshold			Description
	High	Medium	Low	
Daily CDF Risk	>=8 times base	>=4 times base	<4 times base	The maximum daily configuration specific CDF normalized to the base CDF (i.e. no equipment out-of-service).
Daily LERF Risk	>=8 times base	>=4 times base	<4 times base	The maximum daily configuration specific LERF normalized to the base LERF (i.e. no equipment out-of-service).
Weekly ICCDP	>1E-5	1E-5 to 1E-6	<1E-6	The sum of the products of the incremental CDFs and the durations of the various maintenance activities during a single week.
Weekly ICLERP	>1E-6	1E-6 t0 1E-7	<1E-7	The sum of the products of the incremental LERFs and the durations of the various maintenance activities during a single week

For conditions evaluated as a MEDIUM and HIGH risk configuration, actions are taken to re-schedule activities or lower risk. If it is not possible to prevent a MEDIUM or HIGH risk configuration, then the appropriate risk management actions are established in accordance with NO-1-117, Integrated Risk Management.

6.3.3.3 Integrated Probabilistic Risk Assessment – Unplanned LCO Entry

Emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a previously performed assessment. Emergent work as defined in NO-1-117 is "an activity added to a work week after the T-2 Scheduled Risk Assessment Meeting." "T-2" refers to two weeks prior to work execution.

Guidance is provided in the CCNPP risk assessment process to perform a risk assessment on a reasonable schedule commensurate with the safety significance of the condition. Guidance on the performance (or re-evaluation) of the assessment is designed such that it will not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to restore the equipment to service or take compensatory actions.

To minimize the evaluation response time, a qualified PRA analyst is on twenty-four hour call.

6.3.3.4 On-line Risk Assessment – Level 2

The CCNPP on-line risk assessment process directly assesses Level 2 risk by using the LERF metric. See Table 22 above.

6.3.3.5 On-line Risk Assessment – External Events

External Events are qualitatively evaluated by a PRA analyst assessing the event and then adjusting the internal events PRA model.

7.0 Performance Monitoring

The reliability and availability of the DGs are monitored under the Maintenance Rule Program. If the pre-established reliability or availability performance criteria are exceeded for the DGs, they are considered for 10 CFR 50.65 (a)(1) actions, requiring increased management attention and goal setting in order to restore their performance (reliability and availability) to an acceptable level. The performance criteria are risk-informed and, therefore are a means to aid in managing the overall risk profile of the plant. The actual out-of-service time for the DGs will be minimized to ensure the reliability and availability performance criteria for these ESF busses are not exceeded.

In practice, the actual out-of-service time for the DGs and the SBO DG is minimized to ensure that the Maintenance Rule reliability and availability performance criteria for these components are not exceeded. It should be noted that a full fourteen days of unavailability per DG per cycle is not anticipated.

To ensure that the operational safety associated with the extended TS required action completion time does not degrade over time, the Maintenance Rule Program is used as discussed above, to identify and correct adverse trends. Compliance with Maintenance Rule not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out-of-service for testing or maintenance.

8.0 Conclusion

We propose extending the required action completion time for a single DG out of service from seventy-two hours to fourteen days. The risk contributions associated with this extension have been quantitatively evaluated using the current plant-specific probabilistic risk assessments for Calvert Cliffs Units 1 and 2. The changes for a single DG OOS, when considering the seismic improvements of the 0C DG and anticipated unavailabilities, result in a risk reduction. There is also additional risk reduction that was not quantified associated with averting unnecessary plant transients and with reduced risk during shutdown operations. The latter reduction comes as a result of scheduling less DG unavailability while the unit is shutdown.

The second Technical Specification affected involves the required action completion time for declaring the Control Room Emergency Ventilation System (CREVS) inoperable when the Safety–Related back-up power supply (DG) is inoperable. The proposed change extends the current seventy-two hours to twenty-one days when a single DG is inoperable (i.e. 0C is available and three other SR DGs are operable) before the CREVS train is declared inoperable. The risk associated with this required action completion time extension was evaluated in conjunction with the above change to fourteen days. The net risk reduction mentioned above includes this CREVS Technical Specification Required Action Completion Time extension. The DG extension also impacts the H2 analyzer and CRETs Required Action Completion Time. Currently, the CREVS Required Action Completion Time is 7 days and the CRETs and H2 analyzer required action completion time is 30 days. Therefore, the DG OOS time is limited by the CREVS Required Action Completion Time.

The third Technical Specification effected involves the required action completion time when the two DGs on a Unit are both inoperable. The proposed change extends the current two hours to twelve hours when the 0C DG is available and the other two SR DGs are operable. The risk associated with this required action completion time extension was evaluated in conjunction with the other changes. The proposed change is considered acceptable.

ATTACHMENT (2)

DETERMINATION OF SIGNIFICANT HAZARDS

ATTACHMENT (2)

DETERMINATION OF SIGNIFICANT HAZARDS

The proposed amendment revises Technical Specification 3.8.1, AC Sources – Operating to extend to Required Action Completion Time for inoperable diesel generators (DGs). There are three changes proposed to implement this requested extension. The first proposed change will increase the Required Action Completion Time for a single inoperable safety-related DG to 14 days, provided that the 0C DG is available and the other three safety-related DGs are operable.

The second Technical Specification change involves the Required Action Completion Time for declaring the Control Room Emergency Ventilation System, Control Room Emergency Temperature System, and H_2 Analyzer inoperable when the safety-related back-up power supply (DG) is inoperable. The proposed change extends the current 72 hours to 21 days when a single DG is inoperable (i.e., 0C DG is available and three other DGs are operable) before the Control Room Emergency Ventilation System, Control Room Emergency Temperature System, and H_2 Analyzer trains are declared inoperable.

Currently, when both DGs dedicated to redundant safety-related equipment are inoperable, the Required Action Completion Time is two hours. The third proposed change increases this Required Action Completion Time to 12 hours. The 12-hour Required Action Completion Time is only allowed when the 0C DG is available and one other safety-related DG is operable.

Each of the proposed changes have associated changes needed to realign the Required Actions with the proposed changes. An additional proposed change will also make a correction to the Completion Time for what is currently Required Action D.1 so that it correctly reads "once per 8 hours thereafter" instead of "one per 8 hours thereafter."

These proposed changes have been evaluated against the standards in 10 CFR 50.92 and have been determined to not involve a significant hazards consideration, in that operation of the facility in accordance with the proposed amendments:

1. *Would not involve a significant increase in the probability or consequences of an accident previously evaluated.*

   The proposed Technical Specification changes do not affect the design, operational characteristics, function or reliability of the DGs. The DGs are not accident initiators, and extending the DG Required Action Completion Times will not impact the frequency of any previously evaluated accidents. The design basis accidents will remain the same postulated events described in the Updated Final Safety Analysis Report. In addition, extending the DG Required Action Completion Times will not impact the consequences of an accident previously evaluated. The consequences of previously evaluated accidents will remain the same during the proposed extended Required Action Completion Times as during the current Required Action Completion Times. The ability of the remaining DGs to mitigate the consequences of an accident will not be affected since no additional failures are postulated while equipment is inoperable within the Technical Specification Required Action Completion Times. Therefore, the proposed changes will not increase the probability or consequences of an accident previously evaluated.

   The duration of a Technical Specification Required Action Completion Time is determined considering that there is a minimal possibility that an accident will occur while a component is removed from service. A risk informed assessment was performed that concluded that the plant risk is acceptable and consistent with the guidance contained in Regulatory Guide 1.177.

   The additional proposed changes to renumber action requirements and the correction of a misspelled word will not result in any technical changes to the current requirements. Therefore, these additional proposed changes will not increase the probability or consequences of an accident previously evaluated.

2. *Would not create the possibility of a new or different type of accident from any accident previously evaluated.*

   The proposed changes to the Technical Specifications do not impact any system or component in a manner that could cause an accident. The proposed changes will not alter the plant configuration or require any unusual operator actions. The proposed changes will not alter the way any structure, system, or component functions, and will not significantly alter the manner in which the plant is operated. There will be no adverse effect on plant operation or accident mitigation equipment. The response of the plant and the operator following an accident will not be significantly different. In addition, the proposed changes do not introduce any new failure modes. Therefore, the proposed changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Would not involve a significant reduction in a margin of safety.*

   The margin of safety provided by the DGs is to provide emergency back-up power supply to systems required to mitigate the consequences of postulated accidents. The engineered safety features systems on either of the two trains for each unit provide for the minimum safety functions necessary to shutdown the units and maintain it in a safe shutdown condition. Each of the two trains can be powered from one of the offsite power sources or its associated DG. In addition, the 0C DG (Station Blackout DG) is available to provide power to any of the trains. This design provides adequate defense in-depth to ensure that diverse power sources are available to accomplish the required safety functions. Thus, with a safety-related DG out-of-service, there is sufficient means to accomplish the safety functions and prevent the release of radioactive material in the event of an accident.

   The proposed change does not affect any of the assumptions or inputs to the Updated Final Safety Analysis Report and does not reduce the decrease in severe accident risk achieved with the issuance of the Station Blackout Rule, 10 CFR 50.63, "Loss of All Alternating Current Power."

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

ATTACHMENT (3)

MARKED UP TECHNICAL SPECIFICATION PAGES

3.8.1-2

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required LCO 3.8.1.a offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 or SR 3.8.1.2 for required OPERABLE offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	A.2 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)
	<u>AND</u>	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> ~~6~~ 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One LCO 3.8.1.b DG inoperable. INSERT 1	B.~~1~~ 2	Perform SR 3.8.1.1 or SR 3.8.1.2 for the OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.~~2~~ 3	Declare required feature(s) supported by the inoperable DG inoperable when its redundant required feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.~~3~~ 4.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
		OR	
	B.~~3~~ 4.2	Perform SR 3.8.1.3 for OPERABLE DG(s).	24 hours
	AND		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.~~4~~ 5 Restore DG to OPERABLE status.	~~72 hours~~ 14 days <u>AND</u> ~~6~~ 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b
Insert 1 ~~C.~~ D. LCO 3.8.1.c offsite circuit inoperable.	-----------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems-Operating," when Condition ~~C~~ D is entered with no AC power source to a train. --------------------------- ~~C~~ D.1 Perform SR 3.8.1.1 or SR 3.8.1.2 for required OPERABLE offsite circuit(s). <u>AND</u>	1 hour <u>AND</u> Once per 8 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~C.~~ D (continued)	~~C~~.2 D Declare, CREVS, CRETS, or H_2 Analyzer with no offsite power available inoperable when the redundant CREVS, CRETS, or H_2 Analyzer is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	~~C~~.3 D Declare CREVS, CRETS, and H2 Analyzer supported by the inoperable offsite circuit inoperable.	72 hours
~~D.~~ E LCO 3.8.1.c DG inoperable.	----------- NOTE ------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems-Operating," when Condition ~~D~~ E is entered with no AC power source to a train. ----------------------------	
Insert 3	~~D~~.~~1~~ 2 E Perform SR 3.8.1.1 or SR 3.8.1.2 for the OPERABLE required offsite circuit(s).	1 hour <u>AND</u> ~~One~~ ONCE per 8 hours thereafter
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
~~D~~. E (continued)	~~D.2~~ E.3	Declare CREVS, CRETS, or H_2 Analyzer supported by the inoperable DG inoperable when the redundant CREVS, CRETS, or H_2 Analyzer is inoperable.	4 hours from discovery of Condition ~~D~~ E concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	~~D.3~~ E.4.1	Determine OPERABLE DG(s) is not inoperable due to common cause failures. <u>OR</u>	24 hours
	~~D.3~~ E.4.2	Perform SR 3.8.1.3 for OPERABLE DG(s).	24 hours
	<u>AND</u>		
	~~D.4~~ E.5	Declare CREVS, CRETS, and H_2 Analyzer supported by the inoperable DG inoperable.	~~72 hours~~ 21 days

Insert 4

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~F~~ G. Two required LCO 3.8.1.a offsite circuits inoperable. OR One required LCO 3.8.1.a offsite circuit that provides power to the CREVS, CRETS, and H_2 Analyzer inoperable and the required LCO 3.8.1.c offsite circuit inoperable.	~~F~~ G.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition ~~F~~ G concurrent with inoperability of redundant required feature(s)
	AND	
	~~F~~ G.2 Restore one required offsite circuit to OPERABLE status.	24 hours
~~I~~ H. One required LCO 3.8.1.a offsite circuit inoperable. AND One LCO 3.8.1.b DG inoperable.	----------- NOTE ----------- Enter applicable Conditions and Required Actions of LCO 3.8.9, when Condition ~~I~~ H is entered with no AC power source to any train. ------------------------------	
	~~I~~ H.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	~~I~~ H.2 Restore DG to OPERABLE status.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
~~H~~ I. Two LCO 3.8.1.b DGs inoperable. OR LCO 3.8.1.b DG that provides power to the CREVS, CRETS, and H_2 Analyzer inoperable and LCO 3.8.1.c DG inoperable. INSERT 6	~~G.1~~ I.1 I.2 Insert 5	Restore one DG to OPERABLE status.	~~2~~ 12 hours
~~H~~ K. Required Action and associated Completion Time of Condition A, B, C, ~~D~~, E, F, ~~or G~~ G, H, I, or J not met.	~~H~~ K.1	Be in MODE 3.	6 hours
	AND		
	~~H~~ K.2	Be in MODE 5.	36 hours
~~I~~ L. Three or more required LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable.	~~I~~ L.1	Enter LCO 3.0.3.	Immediately

INSERT 1

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.1 Verify both DGs on the other unit OPERABLE and 0C DG available. AND	1 hour AND Once per 24 hours thereafter

INSERT 2

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1.1 Restore both DGs on the other unit to OPERABLE status and 0C DG to available status. OR C.1.2 Restore DG to OPERABLE status.	72 hours

INSERT 3

CONDITION	REQUIRED ACTION	COMPLETION TIME
	E.1 Verify both LCO 3.8.1.b DGs OPERABLE, the other unit's DG OPERABLE and the 0C DG available. AND	1 hour AND Once per 24 hours thereafter

INSERT 4

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Required Action E.1 not met.	F.1.1 Restore both LCO 3.8.1.b DGs and other unit's DG to OPERABLE status and 0C DG to available status. <u>OR</u> F.1.2 Restore DG to OPERABLE status.	72 hours

INSERT 5

CONDITION	REQUIRED ACTION	COMPLETION TIME
	I.1 Verify 0C DG available and one other DG OPERABLE. <u>AND</u>	1 hour

INSERT 6

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. Required Action and associated Completion Time of Required Action I.1 not met.	J.1.1 Restore 0C DG to available status and one other DG to OPERABLE status. <u>OR</u> J.1.2 Restore one DG to OPERABLE status.	2 hours

ATTACHMENT (4)

FINAL TECHNICAL SPECIFICATION PAGES

Section 3.8.1

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Two diesel generators (DGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System; and

c. One qualified circuit between the offsite transmission network and the other unit's onsite Class 1E AC electrical power distribution subsystems needed to supply power to the Control Room Emergency Ventilation System (CREVS), Control Room Emergency Temperature System (CRETS), and H_2 Analyzer and one DG from the other unit capable of supplying power to the CREVS, CRETS, and H_2 Analyzer.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required LCO 3.8.1.a offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 or SR 3.8.1.2 for required OPERABLE offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	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)
	<u>AND</u>		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One LCO 3.8.1.b DG inoperable.	B.1	Verify both DGs on the other unit OPERABLE and OC DG available.	1 hour AND Once per 24 hours thereafter
	AND		
	B.2	Perform SR 3.8.1.1 or SR 3.8.1.2 for the OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.3	Declare required feature(s) supported by the inoperable DG inoperable when its redundant required feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.4.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure. OR	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4.2 Perform SR 3.8.1.3 for OPERABLE DG(s). AND B.5 Restore DG to OPERABLE status.	24 hours 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b
C. Required Action and associated Completion Time of Required Action B.1 not met.	C.1.1 Restore both DGs on the other unit to OPERABLE status and OC DG to available status. OR C.1.2 Restore DG to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. LCO 3.8.1.c offsite circuit 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 a train. ----------------------------	
	D.1 Perform SR 3.8.1.1 or SR 3.8.1.2 for required OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	D.2 Declare, CREVS, CRETS, or H_2 Analyzer with no offsite power available inoperable when the redundant CREVS, CRETS, or H_2 Analyzer is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	D.3 Declare CREVS, CRETS, and H2 Analyzer supported by the inoperable offsite circuit inoperable.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. LCO 3.8.1.c DG inoperable.	----------- NOTE ------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems-Operating," when Condition E is entered with no AC power source to a train. ---------------------------	
	E.1 Verify both LCO 3.8.1.b DGs OPERABLE, the other unit's DG OPERABLE and the OC DG available.	1 hour AND Once per 24 hours thereafter
	AND	
	E.2 Perform SR 3.8.1.1 or SR 3.8.1.2 for the OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	E.3 Declare CREVS, CRETS, or H_2 Analyzer supported by the inoperable DG inoperable when the redundant CREVS, CRETS, or H_2 Analyzer is inoperable.	4 hours from discovery of Condition E concurrent with inoperability of redundant required feature(s)
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. (continued)	E.4.1	Determine OPERABLE DG(s) is not inoperable due to common cause failures.	24 hours
		<u>OR</u>	
	E.4.2	Perform SR 3.8.1.3 for OPERABLE DG(s).	24 hours
	<u>AND</u>		
	E.5	Declare CREVS, CRETS, and H_2 Analyzer supported by the inoperable DG inoperable.	21 days
F. Required Action and associated Completion Time of Required Action E.1 not met.	F.1.1	Restore both LCO 3.8.1.b DGs and other unit's DG to OPERABLE status and OC DG to available status.	72 hours
		<u>OR</u>	
	F.1.2	Restore DG to OPERABLE status.	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two required LCO 3.8.1.a offsite circuits inoperable. OR One required LCO 3.8.1.a offsite circuit that provides power to the CREVS, CRETS, and H_2 Analyzer inoperable and the required LCO 3.8.1.c offsite circuit inoperable.	G.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition G concurrent with inoperability of redundant required feature(s)
	AND	
	G.2 Restore one required offsite circuit to OPERABLE status.	24 hours
H. One required LCO 3.8.1.a offsite circuit inoperable. AND One LCO 3.8.1.b DG inoperable.	----------- NOTE ------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, when Condition H is entered with no AC power source to any train. ----------------------------	
	H.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	H.2 Restore DG to OPERABLE status.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. Two LCO 3.8.1.b DGs inoperable. OR LCO 3.8.1.b DG that provides power to the CREVS, CRETS, and H_2 Analyzer inoperable and LCO 3.8.1.c DG inoperable.	I.1 Verify OC DG available and one other DG OPERABLE. AND I.2 Restore one DG to OPERABLE status.	1 hour 12 hours
J. Required Action and associated Completion Time of Required Action I.1 not met.	J.1.1 Restore OC DG to available status and one other DG to OPERABLE status. OR J.1.2 Restore one DG to OPERABLE status.	2 hours
K. Required Action and associated Completion Time of Condition A, B, C, E, F, G, H, I, or J not met.	K.1 Be in MODE 3. AND K.2 Be in MODE 5.	6 hours 36 hours
L. Three or more required LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable.	L.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
SR 3.8.1.1 through SR 3.8.1.15 are only applicable to LCO 3.8.1.a and LCO 3.8.1.b AC sources. SR 3.8.1.16 is only applicable to LCO 3.8.1.c AC sources.

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	------------------NOTE------------------ Only required to be performed when SMECO is being credited for an offsite source. -- Verify correct breaker alignment and indicated power availability for the 69 kV SMECO offsite circuit.	 Once within 1 hour after substitution for a 500 kV offsite circuit <u>AND</u> 8 hours thereafter
SR 3.8.1.2	Verify correct breaker alignment and indicated power availability for each required 500 kV offsite circuit.	7 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	------------------NOTES------------------ 1. Performance of SR 3.8.1.9 satisfies this Surveillance Requirement. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this Surveillance Requirement as recommended by the manufacturer. When modified start procedures are not used, the voltage and frequency tolerances of SR 3.8.1.9 must be met. -- Verify each DG starts and achieves steady state voltage ≥ 4060 V and ≤ 4400 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	31 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	------------------ NOTES ------------------ 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients below the load limit do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This Surveillance Requirement shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.3 or SR 3.8.1.9. -- Verify each DG is synchronized and loaded, and operates for ≥ 60 minutes at a load ≥ 4000 kW for DG 1A and ≥ 2700 kW for DGs 1B, 2A, and 2B.	31 days
SR 3.8.1.5	Verify each day tank contains ≥ 325 gallons of fuel oil for DG 1A and ≥ 275 gallons of fuel oil for DGs 1B, 2A, and 2B.	31 days
SR 3.8.1.6	Check for and remove accumulated water from each day tank.	31 days
SR 3.8.1.7	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank[s] to the day tank.	31 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	Verify interval between each sequenced load block is within ± 10% of design interval for the load sequencer.	31 days
SR 3.8.1.9	-------------------NOTE------------------- All DG starts may be preceded by an engine prelube period. -- Verify each DG starts from standby condition and achieves, in ≤ 10 seconds, voltage > 4060 V and frequency > 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 4060 V and ≤ 4400 V and frequency of > 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.10	Verify manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit.	24 months
SR 3.8.1.11	-------------------NOTE------------------- Momentary transients outside the load and power factor limits do not invalidate this test. -- Verify each DG, operating at a power factor of ≤ 0.85, operates for ≥ 60 minutes while loaded to ≥ 4000 kW for DG 1A and ≥ 3000 kW for DGs 1B, 2A, and 2B.	24 months
SR 3.8.1.12	Verify each DG rejects a load ≥ 500 hp without tripping.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	Verify that automatically bypassed DG trips are automatically bypassed on an actual or simulated required actuation signal.	24 months
SR 3.8.1.14	Verify each DG: a. Synchronizes with offsite power source while loaded upon a simulated restoration of offsite power; b. Manually transfers loads to offsite power source; and c. Returns to ready-to-load operation.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	-------------------NOTE------------------- All DG starts may be preceded by an engine prelube period. -- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated Engineered Safety Feature actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. maintains steady state voltage ≥ 4060 V and ≤ 4400 V, 4. maintains steady state frequency of ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	For the LCO 3.8.1.c AC electrical sources, SR 3.8.1.1, SR 3.8.1.2, SR 3.8.1.3, SR 3.8.1.5, SR 3.8.1.6, and SR 3.8.1.7 are required to be performed.	In accordance with applicable Surveillance Requirements