April 15, 2005

Mr. Joseph E. Venable
Vice President Operations
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

SUBJECT: WATERFORD STEAM ELECTRIC STATION, UNIT 3 - ISSUANCE OF AMENDMENT RE: EXTENDED POWER UPRATE (TAC NO. MC1355)

Dear Mr. Venable:

The Commission has issued the enclosed Amendment No. 199 to Facility Operating License No. NPF-38 for the Waterford Steam Electric Station, Unit 3 (Waterford 3). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated November 13, 2003, as supplemented by letters dated January 29, March 4, April 15, May 7, May 12, May 13, May 21, May 26, July 14, July 15, July 28, August 10, August 19, August 25, September 1, September 14, October 8 (2 letters), October 13, October 18, October 19, October 21, October 29 (2 letters), November 4, November 8, November 16, and November 19, 2004, and January 5, January 14, February 5, February 16, and March 17, 2005. Entergy Operations, Inc., (Entergy) requested changes to the Facility Operating License and TSs for Waterford 3.

The amendment increases the maximum steady-state reactor core power level from 3441 megawatts thermal (MWt) to 3716 MWt, which is an increase of approximately 8 percent. The increase is considered an extended power uprate (EPU).

By supplemental letter dated July 15, 2004, Entergy decided to implement an Alternative Source Term (AST), as permitted by 10 CFR 50.67, "Accident source term," for calculating accident offsite doses and doses to control room personnel. This request has been reviewed by the U.S. Nuclear Regulatory Commission staff and the amendment was issued on March 29, 2005.

The staff is not providing a technical evaluation of Entergy's dose analyses using the original licensing source term in the attached safety evaluation (SE) (Section 2.9) for the EPU, and has referred to the SE for the AST license amendment. The staff's finding of acceptability for the proposed increase in power uprate is based on the AST application meeting the requirements of 10 CFR 50.67 and General Design Criterion 19, and the staff's approval of the request for a full-scope implementation of an AST for Waterford 3 via letter dated March 29, 2005.

In the supplemental letter dated February 5, 2005, Entergy has a commitment as follows:

> Prior to exceeding 3441 MWt, Entergy will submit, for NRC review and approval, a description of how Entergy accounts for instrument uncertainty for each Technical Specification parameter impacted by the Waterford 3 Extended Power Uprate.

This commitment is included in the amendment as a license condition, as discussed during a telephone call with you on April 14, 2005. You will need to submit a separate license amendment request pursuant to 10 CFR 50.90 and then receive NRC approval of that request, via a separate license amendment, to complete this license condition.

We want to provide some observations on the overall conduct of this review that resulted in the unusually large expenditure of staff resources and the extended schedule. The completeness and thoroughness of the engineering work and project planning supporting your application appear to have evolved during the NRC's review rather than having been developed up front. There were many problems, changes, and errors that arose during the course of the review, some identified by the staff and others by Entergy, that could and should have been anticipated and addressed before you submitted the amendment application. Similarly, we believe you could have taken fuller advantage of your Arkansas Nuclear One, Unit 2, EPU experience. We are conducting a lessons-learned evaluation to assess our review experience with the new EPU review standard and to determine whether we could have detected these issues in your application during our acceptance review. We hope that you too will critically review your performance for any useful lessons learned.

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

Sincerely,

/RA by T. Alexion for/

N. Kalyanam, Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-382

Enclosures: 1. Amendment No. 199 to NPF-38
2. Safety Evaluation

cc w/encls: See next page

This commitment is included in the amendment as a license condition, as discussed during a telephone call with you on April 14, 2005. You will need to submit a separate license amendment request pursuant to 10 CFR 50.90 and then receive NRC approval of that request, via a separate license amendment, to complete this license condition.

We want to provide some observations on the overall conduct of this review that resulted in the unusually large expenditure of staff resources and the extended schedule. The completeness and thoroughness of the engineering work and project planning supporting your application appear to have evolved during the NRC's review rather than having been developed up front. There were many problems, changes, and errors that arose during the course of the review, some identified by the staff and others by Entergy, that could and should have been anticipated and addressed before you submitted the amendment application. Similarly, we believe you could have taken fuller advantage of your Arkansas Nuclear One, Unit 2, EPU experience. We are conducting a lessons-learned evaluation to assess our review experience with the new EPU review standard and to determine whether we could have detected these issues in your application during our acceptance review. We hope that you too will critically review your performance for any useful lessons learned.

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

Sincerely,
/RA by T. Alexion for/
N. Kalyanam, Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-382

Enclosures: 1. Amendment No. 199 to NPF-38
2. Safety Evaluation

cc w/encls: See next page

DISTRIBUTION: See next page

Accession No.: ML051030068 TS/License pages: Package: ML051030082
*Minor/Editorial Changes from SE input **with change to cover letter

OFFICE	PDIV-1/PM	PDIV-1/LA	EMCB/A	EMCB/B	EMCB/C	EMEB/B	EEIB/A
NAME	TAlexion for NKalyanam	DJohnson	MMitchell	JTC for TChan	LLund	KManoly	AMarinos
DATE	4/11/05	4/11/05	2-17-05	2-28-05	2-24-05	2-23-05	2-24-05

EEIB/B**	SPLB/A	SPLB/B	SPSB/C	SRXB/B	IROB/B	IEPB/A	SPSB/BC*
RJenkins	SJones	SWeerakody	RDennig	DCoe	DTrimble	DThatcher	MTschiltz
2-28-05	2-24-05	3-3-05	2-23, 23, 24-05	2-25-05	3-14-05	2-24-05	10-7-04

SRXB/BC	PDIV-1/SC	PDIV/D	OGC	DLPM/D**	NRR/D
JWermiel	AHowe	HBerkow	APHodgdon nlo	TMarsh	JDyer
4-5-05 email	4/11/05	4/11/05	3-25-05	4/12/05	4/15/05

OFFICIAL RECORD COPY

Distribution for letter dated: April 15, 2005

SUBJECT: WATERFORD STEAM ELECTRIC STATION, UNIT 3 - ISSUANCE OF AMENDMENT RE: EXTENDED POWER UPRATE (TAC NO. MC1355)

DISTRIBUTION:
PUBLIC
PDIV-1 Reading
RidsNrrDlpmLpdiv (HBerkow)
RidsNrrDlpmLpdiv1 (AHowe)
RidsNrrLADJohnson
RidsNrrPMNKalyanam
RidsOgcRp
G. Hill (2)
RidsAcrsAcnwMailCenter
RidsNrrDipmIrob (TBoyce)
RidsRgn4MailCenter (AHowell)
RidsNrrDlpmDpr (SWall)
J. Medoff
J. Tsao
R. Davis
C. Wu
T. Scarbrough
N. Trehan
J. Lazevnick
H. Li
A. Stubbs
J. Tatum
N. Iqbal
R. Lobel
M. Hart
L. Brown
C. Liang
S. Miranda
F. Orr
W. Lyons
P. Clifford
J. Cai
S. Dennis
R. Pettis
M. Stutzke
J. Stang
L. Raghavan

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-382

WATERFORD STEAM ELECTRIC STATION, UNIT 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 199
License No. NPF-38

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

   A. The application for amendment by Entergy Operations, Inc. (EOI) dated November 13, 2003, as supplemented by letters dated January 29, March 4, April 15, May 7, May 12, May 13, May 21, May 26, July 14, July 15, July 28, August 10, August 19, August 25, September 1, September 14, October 8 (2 letters), October 13, October 18, October 19, October 21, October 29 (2 letters), November 4, November 8, November 16, and November 19, 2004, and January 5, January 14, February 5, February 16, and March 17, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.2. of Facility Operating License No. NPF-38 is hereby amended to read as follows:

   2. Technical Specifications and Environmental Protection Plan

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 199 , and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. EOI shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. As stated in the licensee's letter dated February 5, 2005, the licensee committed as follows: "Prior to exceeding 3441 MWt, Entergy will submit, for NRC review and approval, a description of how Entergy accounts for instrument uncertainty for each Technical Specification parameter impacted by the Waterford 3 Extended Power Uprate." Accordingly, subject to completion of this condition, the licensee shall not operate the Waterford 3 facility at a power level exceeding 3441 MWt.

4. This license amendment is effective as of its date of issuance and shall be implemented during restart from refueling outage 13 in the spring of 2005, or upon NRC approval of the completion of License Condition 3, above, whichever comes later.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

J. E. Dyer, Director
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: April 15, 2005

ATTACHMENT TO LICENSE AMENDMENT NO. 199

TO FACILITY OPERATING LICENSE NO. NPF-38

DOCKET NO. 50-382

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

Remove		Insert
	License	
4		4
	Technical Specifications	
IV		IV
VI		VI
VIII		VIII
XV		XV
XIX		XIX
XXII		XXII
XXIII		XXIII
1-3		1-3
1-6		1-6
2-3		2-3
3/4 1-6		3/4 1-6
3/4 1-7		3/4 1-7
3/4 1-12		3/4 1-12
3/4 1-13		3/4 1-13
3/4 1-14		3/4 1-14
--------		3/4 1-14a
3/4 2-11		3/4 2-11
3/4 2-13		3/4 2-13
3/4 3-19		3/4 3-19
3/4 3-20		3/4 3-20
3/4 4-18		3/4 4-18
3/4 4-33		3/4 4-33
3/4 5-1		3/4 5-1
3/4 5-9		3/4 5-9
3/4 6-13		3/4 6-13
3/4 7-1		3/4 7-1
3/4 7-3		3/4 7-3
3/4 7-6		3/4 7-6
3/4 7-9		3/4 7-9
3/4 7-9a		3/4 7-9a
-------		3/4 7-9b
3/4 8-1		3/4 8-1

ATTACHMENT TO LICENSE AMENDMENT NO. 199

TO FACILITY OPERATING LICENSE NO. NPF-38

DOCKET NO. 50-382

(Continued)

Remove	Insert
3/4 8-8	3/4 8-8
5-1	5-1
5-6	5-6
5-7	5-7
5-8	-----
5-9	-----
6-7	6-7
6-20a	6-20a

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 199 TO

FACILITY OPERATING LICENSE NO. NPF-38

ENTERGY OPERATIONS, INC.

WATERFORD STEAM ELECTRIC STATION, UNIT 3

DOCKET NO. 50-382

1.0 INTRODUCTION

1.1 Application

By application dated November 13, 2003, (Reference 1), as supplemented by letters dated January 29 (Reference 2), March 4 (Reference 3), April 15 (Reference 4), May 7 (Reference 5), May 12 (Reference 6), May 13 (Reference 7), May 21 (Reference 8), May 26 (Reference 9), July 14 (Reference 10), July 15 (Reference 11), July 28 (Reference 12), August 10 (Reference 13), August 19 (Reference 14), August 25 (Reference 15), September 1 (Reference 16), September 14 (Reference 17), October 8 (Reference 18 and Reference 19), October 13 (Reference 20), October 18 (Reference 21), October 19 (Reference 22), October 21 (Reference 23), October 29 (Reference 24 and Reference 25), November 4 (Reference 26), November 8 (Reference 27), November 16 (Reference 28), and November 19, 2004 (Reference 29), and January 5 (Reference 30), January 14 (Reference 70), February 5 (Reference 71), February 16 (Reference 72), and March 17, 2005 (Reference 75), Entergy Operations, Inc., (Entergy, the licensee) requested changes to the Facility Operating License and Technical Specifications (TSs) for the Waterford Steam Electric Station, Unit 3 (Waterford 3).

The proposed changes would increase the maximum steady-state reactor core power level from 3441 megawatts thermal (MWt) to 3716 MWt, which is an increase of approximately 8 percent. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

The Waterford 3 site is located in southeastern Louisiana on the west bank of the Mississippi River near the town of Taft in Saint Charles Parish. The nearest population center is Kenner, 13 miles east of the site. New Orleans is approximately 25 miles east-southeast of the site.

Waterford 3 is a pressurized-water reactor (PWR) plant of the Combustion Engineering (CE) design with a dry, ambient pressure containment.

The NRC originally licensed Waterford 3 on March 16, 1985, for operation at a reactor core power not to exceed 3390 MWt. By Amendment No. 183, dated March 29, 2002 (ML020910734), the NRC granted a measurement uncertainty recapture uprate to Waterford 3 of approximately 1.5 percent, allowing the plant to be operated at 3441 MWt. This increase in licensed power was supported by a reduction in the power measurement uncertainty at full power from 2 percent to less than 0.5 percent using ultrasonic flow measurement equipment for feedwater flow. Therefore, the proposed EPU would result in an increase of approximately 9.6 percent over the original licensed power level and 8 percent over the current licensed power level for Waterford 3.

The reactor coolant system (RCS) of the plant includes: (1) the reactor vessel (RV); (2) two parallel reactor coolant loops, each consisting of one steam generator (SG) and two reactor coolant pumps (RCPs) (each cold leg is served by a single RCP); (3) a single hot leg supplying each SG, which divides the return flow into two RCS cold legs; (4) a pressurizer connected to one of the reactor outlet pipes (hot legs); and (5) associated piping out to a suitable isolation valve boundary.

The RCS transfers heat from the reactor core to the secondary coolant system via the SG. The RCS pressure boundary also establishes a boundary against the uncontrolled release of radioactive material from the reactor core and the primary coolant. The SGs are of vertical U-tube design with one RCS hot leg inlet and two cold leg outlets, and with an integral moisture separator and steam dryers.

The general mechanical configuration and thermal power rating of the core are 217 fuel assemblies with a 16 x 16 fuel pattern and a 150 inches-long core that operates at a power density of about 95.6 kilowatts (kW) per liter.

Shutdown cooling (SDC) is provided by a multi-mode system that also performs the low-pressure safety injection (LPSI) function as part of the emergency core cooling system (ECCS). The ECCS consists of LPSI and high pressure safety injection (HPSI) pump subsystems, and four safety injection tanks. All of these ECCS subsystems inject into the four RCS cold legs. The shutoff head of the HPSI pumps is less than RCS normal operating pressure. Therefore, the RCS must depressurize before these pumps can provide any makeup. The refueling water storage pool (RWSP) is the water source for the HPSI and LPSI pumps.

The chemical and volume control system (CVCS) is responsible for maintaining the proper water inventory in the RCS and maintaining the water purity and the proper concentration of neutron absorbing and corrosion inhibiting chemicals in the reactor coolant.

The shutdown cooling system (SDCS) provides for SDC of the reactor after the RCS has been depressurized to less than 377 psig and cooled to less than 350 ^{o}F.

The component cooling water system (CCWS) serves to remove heat from the reactor auxiliaries and to transfer it to the cooling towers for rejection to the atmosphere. The CCWS ensures continuous operation or safe-shutdown of the plant under all modes of operation. The auxiliary CCWS removes heat, when required, from the component cooling water (CCW) heat exchangers during normal operation, normal shutdown, and accident conditions. The Auxiliary CCWS (ACCWS) is required to operate whenever the heat rejection capacity of the CCWS is exceeded, or whenever ambient conditions prevent the CCWS from rejecting its required heat load.

1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates" (Reference 31) to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and Reference 31, the licensee described the differences and provided evaluations consistent with the design basis of the plant.

The licensee also used topical reports, other documents for guidance related to the scope of the proposed EPU, NRC staff approvals, ranges of applicability, any limitations/restrictions associated with the documents, and consistency of the licensee's application with the ranges of applicability and limitations/restrictions. These are listed in the reference section.

The licensee plans to implement the Waterford 3 EPU in one step. The licensee plans to make the modifications necessary to implement the EPU during the next refueling outage (RFO) in the spring of 2005. Subsequently, the plant will be operated at 3716 MWt starting in Cycle 14.

1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed EPU. The following is a list of these modifications.

- Upgrade the high pressure turbine
- Rewind the main generator and provide associated auxiliaries
- Install higher capacity main generator output circuit breakers, and disconnect switches and bus work
- Modify main transformers
- Replace/upgrade, as necessary, control valves for the heater drain (HDR) system
- Make instrument and control changes (e.g., lower SG pressure trip setpoint)
- Stake the condenser tubes

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this safety evaluation (SE).

1.5 Method of NRC Staff Review

The NRC staff reviewed the licensee's application to evaluate the licensee's assessment of the impact of the proposed EPU on design-basis analyses and to ensure that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) activities proposed will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public. The NRC staff evaluated the licensee's application and supplements. The NRC staff's evaluation included a review of selected Westinghouse Electric Company, LLC (Westinghouse or W), calculations, upon which certain accident analyses presented in the uprating application were based. These calculations were selected by the NRC staff, as representative of events that are (1) sensitive to the plant's uprated conditions, and (2) analyzed with methods that have not been heretofore applied in the Waterford 3 docket (e.g., the CENTS code). Specifically, two NRC staff members visited Westinghouse's offices in Windsor, Connecticut, on August 11 and 12, 2004, and audited calculations that supported the steam line break (SLB), feedwater (FW) line break (FWLB), and loss of FW analyses. At the staff's request, Westinghouse provided copies of these calculations, and several others pertaining to the building of the CENTS Waterford 3 model, for further review at the NRC offices. These documents are subject to applicable proprietary-information controls.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this SE.

Audits of analyses supporting the EPU were conducted in relation to the following topics:

1) Loss of FW analysis
2) FWLB analysis
3) SLB analysis
4) Dose calculations and AST
5) Long-term cooling (decay heat removal) capability.

The results of the audits are discussed in the relevant portions of Section 2.0 of this SE.

Independent NRC staff calculations were performed in relation to the following topics:

6) Small break LOCA Analysis
7) FW Line Break Analysis.

The results of the calculations are discussed in the relevant portions of Section 2.0 of this SE.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The RV material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Title 10 of the Code of Federal Regulations

(10 CFR) Part 50, Appendix H, provides the NRC staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focused on the effects of the proposed EPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC) 14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) Appendix H to 10 CFR Part 50, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with Appendix H to 10 CFR Part 50. Specific review criteria are contained in Standard Review Plan (SRP) Section 5.3.1 and other guidance provided in Matrix 1 of Reference 31.

Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RV materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. Appendix H to 10 CFR Part 50, invokes, by reference, the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." The ASTM Standard Practice E185 provides guidelines for designing and implementing the RV materials surveillance programs for operating light-water reactors (LWRs), including guidelines for determining RV surveillance capsule withdrawal schedules. Entergy is applying the 1982 Version of ASTM Standard Practice E185 (ASTM E185-82) as its basis for implementing the Waterford 3 RV materials surveillance program. Appendix H to 10 CFR Part 50 requires that technical summary reports on RV surveillance capsule testing be submitted to the NRC within one year of the surveillance capsule withdrawals.

The licensee discussed the impact of the 8 percent EPU on the RV material surveillance program in Section 2.1.1 of the EPU analysis report. The current NRC-approved version of the licensee's RV materials surveillance program withdrawal schedule is given in Revision 8 of Table 5.3-10 (dated May 1996) of the Waterford 3 Final Safety Analysis Report (FSAR). In April 2002, a second surveillance capsule (Capsule 263E) was removed from the Waterford 3 RV and tested. The test results for Capsule 263E are given in WCAP-16002, Revision 0 (Reference 32), which was submitted to the NRC in a letter dated March 28, 2003.

By Reference 3, the licensee requested that the NRC staff review the updated RV surveillance capsule withdrawal schedule in Table 7-1 of Reference 32, as part of its review of the 8 percent EPU. The WCAP report amended the withdrawal schedule to account for the updated neutron fluence dosimetry results that were obtained from dosimetry testing on Capsule 263E. The NRC staff's evaluation of the changes to the RV surveillance capsule withdrawal schedule is given in the paragraphs that follow.

The licensee stated that the revised, limiting neutron fluence for the RV at the clad/base-metal interface under the uprated conditions, as projected through 32 effective full power years

(EFPY)[1] of operation, is 2.48 X 10^{19} neutron per square centimeter (n/cm^2) (E $ 1.0 Mega Electron Volts (MeV)). The NRC staff has confirmed that the methods used to calculate the neutron fluence value for the Waterford 3 RV were valid and, based on the 8 percent EPU, concluded that 2.48 X 10^{19} n/cm^2 (E $ 1.0 MeV) is an acceptable 32 EFPY limiting neutron fluence value for the Waterford 3 RV. According to independent pressurized thermal shock reference temperature (RT_{PTS}) calculations performed by the NRC staff (refer to the assessment in Section 2.1.3 of this SE), the increase in the adjusted reference temperature (i.e., ΔRT_{PTS} value) for the limiting material in the Waterford 3 RV at 32 EFPY and EPU conditions is less than 100 EF. Based on this ΔRT_{PTS} value, ASTM Standard Practice E185-82 requires that a minimum of three surveillance capsules be removed from the Waterford 3 RV. The updated Waterford 3 RV materials surveillance program withdrawal schedule in Table 7-1 in Reference 32 is a three capsule withdrawal schedule and complies with this minimum requirement. Three additional capsules remain in the RV as “standby” capsules which may be removed and tested at the licensee’s option.

Table 7-1 of Reference 32 changes the following aspects of the withdrawal schedule that is currently given in Revision 8 of Table 5.3-10, Waterford 3 Updated Final Safety Analysis Report (UFSAR):

- Changes the third capsule for removal from Capsule 277E to Capsule 83E and designates Capsule 277E as a standby capsule for the surveillance program.

- Changes the lead factor for Capsules 83E, 97E, 263E, and 277E from 1.26 to 1.18, and the lead factor for Capsules 104E and 284E from 0.81 to 0.83.

- Changes the removal time values and neutron fluence values for Capsule 263E from projected values (15 EFPY and 2.18 X 10^{19} n/cm^2 [E $ 1.0 MeV], respectively) to the actual values reported in WCAP-16002, Revision 0 (13.83 EFPY and 1.45 X 10^{19} n/cm^2 [E $ 1.0 MeV], respectively).

- Projects the time of removal and neutron fluences for Capsule 83E to be 26 EFPY and 2.47 X 10^{19} n/cm^2 (E $ 1.0 MeV).

Since the 83E and 277E capsules are located in equivalent RV locations and will be exposed to equivalent neutron radiation fields, the NRC staff considers the changes to designate Capsule 83E as the third capsule for removal and to designate Capsule 277E as a standby capsule to be administrative in nature and are acceptable. The updates of the lead factors for all of the Waterford 3 capsules are based on the fluence dosimetry results from Capsule 263E as reported in Reference 32. The NRC staff has determined that the dosimetry methods summarized in the report are acceptable because they conform to the NRC staff’s recommended dosimetry methodology in Regulatory Guide (RG) 1.190 (Reference 33). Therefore, the NRC staff concludes that the revised lead factors and neutron fluences for the capsules, as calculated in accordance with these dosimetry methods, are acceptable.

The removal time and neutron fluence value for Capsule 263E have been changed from projected values to actual reported values as based on the data reported in Reference 32.

---

1 32 EFPY corresponds to a licensed operating term of 40 years at an 80 percent capacity factor.

Since the NRC staff has accepted both the neutron fluence dosimetry methodology and neutron fluence values reported in Reference 32, the NRC staff concludes the reported data for Capsule 263E are acceptable. The NRC staff, therefore, concludes that updated data reported in Table 7-1 of Reference 32 for Capsule 263E are acceptable.

The NRC staff also compared the reported removal time for Capsule 263E to the acceptance criteria in ASTM E185-82 for a three capsule withdrawal schedule, which states that the second surveillance capsule in a three capsule withdrawal program should be removed at a time approximating 15 EFPY or at a time when the fluence for the capsule corresponds to the equivalent fluence for the RV at end-of-life (EOL), whichever comes first. Since Capsule 263E was removed at 13.83 EFPY, the NRC staff concludes that the removal of the capsule complied with the Standard Practice because the withdrawal of the surveillance capsule was performed during the RFO closest to 15 EFPY and because the capsule had accumulated a neutron fluence less than the EOL fluence for the RV. Therefore, the NRC staff concludes that the licensee removed Capsule 263E at an acceptable time.

ASTM E185-82 states that the third surveillance capsule in a three capsule withdrawal program should be removed at a time when the fluence for the capsule corresponds to a fluence at “not less than once or greater than twice the peak EOL vessel fluence.” According to the new schedule in Table 7-1 of Reference 32, the licensee has designated Capsule 83E as the new third capsule for removal and has indicated that the capsule will be removed at approximately 26 EFPY with a projected fluence of 2.47 X 10^{19} n/cm^2 (E $ 1.0 MeV). This is based on a neutron flux projection of 2.38 X 10^{10} n/cm^2-sec (E $ 1.0 MeV) for the RV’s 83E location. The NRC staff confirmed that 2.47 X 10^{19} n/cm^2 (E $ 1.0 MeV) is the best-estimate projected fluence value for Capsule 83E at 26 EFPY, when the capsule is projected to be removed from the Waterford 3 RV. The projected capsule fluence for Capsule 83E at 26 EFPY is essentially the same as the limiting neutron fluence projected Waterford 3 RV at EOL (i.e., approximately 2.48 X 10^{19} n/cm^2 [E $ 1.0 MeV] at 32 EFPY, as cited in Section 6 of Reference 32). Based on this assessment, the NRC staff concludes that the 26 EFPY removal time for Capsule 83E meets the withdrawal schedule removal criterion in ASTM E185-82 for the third capsule in a three capsule withdrawal schedule and, therefore, is acceptable.

Technical Specification No. 4.4.8.1.2 requires the licensee to implement its RV material surveillance program in accordance with 10 CFR Part 50, Appendix H, and with the RV surveillance program withdrawal schedule that is specified in Table 5.3-10 of the Waterford 3 UFSAR. The current version of UFSAR Table 5.3-10 is not updated with the new RV surveillance capsule withdrawal schedule in Table 7-1 of WCAP-16002, Revision 0 (Reference 32), which is being approved as part of this EPU review. Therefore, the licensee should use the 10 CFR 50.59 process to update Waterford 3 UFSAR Table 5.3-10 with the new RV surveillance capsule withdrawal schedule in Table 7-1 of WCAP-16002, Revison 0.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RV surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the RV capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR Part 50, Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC 14 and GDC 31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RV material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

Appendix G to 10 CFR Part 50 provides fracture toughness requirements for ferritic (low alloy steel or carbon steel) materials in the RCPB, including requirements on the upper-shelf energy (USE) values used for assessing the remaining safety margins of the RV materials against ductile tearing and requirements for calculating pressure-temperature (P-T) limits for the plant. These P-T limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences (AOOs) and hydrostatic tests. The NRC staff's review of the USE assessments covered the impact of the EPU on the neutron fluence values for the RV beltline materials and the USE values for the RV materials through the end of the current licensed operating period for Waterford 3. The NRC staff's P-T limits review covered the P-T limits methodology and the calculations for the number of the EFPY specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

The NRC's acceptance criteria for USE and P-T limits are based on (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) Appendix G to 10 CFR Part 50, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) compliance with 10 CFR 50.60, which requires compliance with Appendix H to 10 CFR Part 50. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of Reference 31.

Technical Evaluation

Upper-Shelf Energy Value Calculations

Appendix G to 10 CFR Part 50 provides the NRC staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires RV beltline materials to have a minimum USE value of 75 foot pounds (ft-lb) in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analytical engineering that lower values of USE would provide acceptable margins of safety against the fracture equivalent to those required by Appendix G of Section XI to the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H, RV materials surveillance program.

The licensee discussed the impact of the 8 percent EPU on the USE values for the RV beltline materials in Section 2.1.2 of Reference 1. In this section, the licensee stated that the limiting USE value for the RV beltline materials is 71 ft-lb at the end of the current operating term for the unit and that Table 2.1-1 of the EPU safety analysis report (SAR) provides the USE assessments for all of the plate and weld materials in the beltline region of the Waterford 3 RV. The licensee also indicated that the assessments included the incorporation of surveillance data reported in Reference 32, which includes the surveillance data reported for Capsule 263E and the reanalyzed surveillance data for Capsule 97E.

The NRC staff performed an independent calculation of the EOL USE values for the Waterford 3 RV beltline materials using the limiting 32 EFPY neutron fluence value for the 1/4T location of the vessel, as revised for the EPU conditions. The NRC staff's independent assessment included the incorporation of the pertinent surveillance data reported in Reference 32 for Capsules 263E and 97E. The NRC staff determined that, under the EPU conditions, Intermediate Shell Plate 1003-3 (Plate Heat No. 56484-1) is the limiting 32 EFPY beltline material for USE and calculated a 71 ft-lb USE value for this material at 32 EFPY. This value is in agreement with the limiting 32 EFPY USE value cited by the licensee for the EPU and exceeds the 50 ft-lb EOL USE requirement in 10 CFR Part 50, Appendix G, for operating reactors. Therefore, the NRC staff concludes that the beltline materials in the Waterford 3 RV will have acceptable remaining values of USE under the EPU conditions for the unit.

Pressure-Temperature Limit Calculations

Section IV.A.2 of 10 CFR Part 50, Appendix G, requires that the P-T limits for operating reactors be at least as conservative as those that would be generated if the methods of calculation in the ASME Code, Section XI, and Appendix G to 10 CFR Part 50 were used to calculate the P-T limits. The rule also requires that the P-T limit calculations account for the effects of neutron irradiation on the P-T limit values for the RV beltline materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H, RV materials surveillance program.

On October 22, 2003, the licensee submitted License Amendment Request No. 250 for Waterford 3 Facility Operating License NPF-38 (ML041620063). In this license amendment request, the licensee requested approval of the P-T limits for Waterford 3, as projected through 32 EFPY of operation. The NRC staff has confirmed that the neutron fluences used for the 32 EFPY P-T limit assessment bound the 32 EFPY neutron fluences for the Waterford 3 RV under the EPU conditions. Therefore, the neutron fluences credited for the EPU were accounted for and approved by the NRC staff in the new 32 EFPY P-T limit curves for Waterford 3. The NRC staff's SE for the proposed 32 EFPY P-T limit curves for Waterford 3 is in the NRC staff's letter dated June 16, 2004 (ML041700466).

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials and P-T limits for the plant. The NRC staff concludes that the licensee has adequately addressed changes in neutron fluence and their impacts on the USE values for the Waterford 3 RV and P-T limits for the plant. The NRC staff concludes that the Waterford 3 RV beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operating license for the facility. The NRC staff also concludes that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed EPU conditions. Based on this assessment, the NRC staff concludes that the Waterford 3 facility will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60, and the licensee will be able to comply with GDC 14 and GDC 31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the proposed P-T limits.

2.1.3 Pressurized Thermal Shock

Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided for supporting reactor operation. The NRC staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The NRC staff's review covered the PTS methodology and the calculations for the RT_{PTS} at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) fracture toughness criteria for protection against PTS events which are set via 10 CFR 50.61. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of Reference 31.

Technical Evaluation

The NRC staff has established requirements in 10 CFR 50.61 that are designed to protect the RVs of PWRs against the consequences of PTS events. The rule requires licensees of PWRs to calculate a nil-ductility reference temperature at EOL (i.e., an RT_{PTS} value for protecting the RV material against PTS) for each ferritic base metal and weld material in the beltline region of the RV. Ferritic materials are materials that are made from a carbon or low-alloy steel. The rule also requires the RT_{PTS} values to be maintained below a maximum screening threshold for the values throughout the life of the facilities. The rule's screening criteria are 270 EF for axial weld materials and base metal materials (i.e., plates or forging materials) and 300 EF for circumferential weld materials.

A required methodology for calculating these RT_{PTS} values, which is based on the calculation methods in RG 1.99 (Reference 34), is provided in 10 CFR 50.61. For materials in the beltline region of the vessel, the rule requires that the calculations account for the effects of neutron irradiation on the RT_{PTS} values for the materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RV materials surveillance program (i.e., 10 CFR Part 50, Appendix H).

The licensee discussed the impact of the EPU on the Waterford 3 PTS assessment in Reference 1, Section 2.1.3. In this section, the licensee stated that the PTS assessment for the

Waterford 3 RV under the uprated conditions is limited by the evaluation for Lower Shell Plate —1004-2 (Plate Heat No. 57286-1) and that this material has a limiting RT_{PTS} value of 53 EF at EOL (i.e., 32 EFPY). The licensee also stated that Table 2.1-1 in Reference 1 provides the PTS assessments for all of the plate and weld materials in the beltline region of the Waterford 3 RV and that the assessments included the incorporation of surveillance data reported in Reference 32, for Capsules 263E and 97E.

The NRC staff performed an independent calculation of the EOL RT_{PTS} values for the Waterford 3 RV beltline materials using the limiting 32 EFPY neutron fluence value for the clad-metal interface location of the vessel at EPU conditions. The NRC staff's independent assessment included the incorporation of the pertinent surveillance data reported in Reference 32, for Capsules 263E and 97E. The NRC staff determined that, under the EPU conditions, Intermediate Shell Plate —1004-2 (Plate Heat No. 57286-1) is the limiting 32 EFPY beltline material for PTS. The NRC staff calculated an RT_{PTS} value of 49 EF for this material at 32 EFPY. The RT_{PTS} value calculated by the licensee for material at 32 EFPY is slightly more conservative than the corresponding value calculated by the NRC staff. Both the RT_{PTS} values cited by the licensee and the NRC staff are well within the rule's maximum upper limit for RT_{PTS} values established for base metal materials (i.e., the RT_{PTS} values are less than 270 EF). The NRC staff, therefore, concludes that the beltline materials in the Waterford 3 RV will have acceptable safety margins against the consequences of PTS events under the EPU conditions, as is mandated by the PTS requirements of 10 CFR 50.61.

<u>Summary</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the PTS for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on PTS. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDC 14, GDC 31, and 10 CFR 50.61 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to PTS.

2.1.4 Reactor Internal and Core Support Materials

<u>Regulatory Evaluation</u>

The reactor internals and core supports include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the RCS). The NRC staff's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination (NDE) procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internal and core support materials are based on GDC 1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria are contained in SRP Section 4.5.2, and other review criteria and guidance are provided in Matrix 1 of Reference 31. Matrix 1 of Reference 31 provides references to the NRC's approval of the recommended guidelines for RV internals in Topical Report WCAP-14577 (Reference 35) and Topical Report BAW-2248A (Reference 36).

Technical Evaluation

The licensee discussed the impact of the EPU on the structural integrity of the Waterford 3 RV internal components in Section 2.1.4 of the EPU analysis report. In its SAR for the EPU, the licensee concluded that the EPU would not impact the safety margins associated with the structural integrity of the Waterford 3 RV internal components because the EPU does not increase the operating temperature for the reactor coolant (based on the hot leg temperature) and because the EPU actually results in a decrease in high energy gamma and neutron flux exposures.

The RV internals of PWRs may be susceptible to the following aging effects:

- cracking, induced by thermal cycling (fatigue-induced cracking), stress corrosion cracking (SCC), or irradiation assisted stress corrosion cracking (IASCC)
- loss of fracture toughness properties, induced by irradiation exposure for all stainless steel grades, or the synergistic effects of irradiation exposure and thermal aging for cast austenitic stainless steel (CASS) grades
- stress relaxation in bolted, fastened, keyed, or pinned RV internal components, induced by irradiation exposure and/or exposure to elevated temperatures
- void swelling, induced by irradiation.

Reference 31 provides the NRC staff's basis for evaluating the potential for EPUs to induce these aging effects. Matrix 1 of Reference 31 states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels inducing IASCC in RV internal components is given in Reference 35. Reference 35 establishes a threshold of 1 X 10^{21} n/cm^2 ($E \geq 0.1$ MeV) for the initiation of IASCC or reduction in fracture toughness properties in PWR RV internal components made from stainless steel (including CASSs) or Alloy 600/82/182 materials. In Matrix 1 of Reference 31, the NRC staff established guidance that plants exceeding this threshold of neutron irradiation would either have to establish plant-specific degradation management programs for managing the aging effects associated with their RV internals or else indicate that the licensees would participate in industry programs designed for investigating and managing age-related degradation in the RV internal components.

The NRC staff determined that the neutron fluence values for the RV internal components in the vicinity of the Waterford 3 reactor core were on the order of 3 X 10^{22} – 5 X 10^{22} n/cm^2 ($E \geq 0.1$ MeV). In a telephone call with the licensee on June 9, 2004, the NRC staff informed Entergy that, consistent with Matrix 1 of Reference 31, either an inspection plan would need to be established to manage the age-related degradation in the Waterford 3 RV internals, or that a commitment would be needed indicating that Entergy would participate in the industry's initiatives on age-related degradation of PWR RV internal components. In its supplemental letter dated February 5, 2005 (Reference 71), the licensee committed to the following management program for the Waterford 3 RV internal components:

> Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components. Entergy commits to:

a. continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,
b. evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to Waterford 3,
c. incorporate the resulting reactor vessel internals inspections into the Waterford 3 augmented inspection plan as appropriate.

In addition, as requested by the NRC, a description of the program, including the inspection plan, will be submitted to the NRC for review and approval. The submittal date will be within 24 months after the final EPRI MRP recommendations are issued or within five years from the date of issuance of the uprated license, whichever comes first.

The licensee's commitments to participate in the industry's research program of degradation of PWR RV internal components, to develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives, and to submit an RV internals inspection plan for NRC review and approval are consistent with Matrix 1 of Reference 31 and are, therefore, acceptable. Based on this assessment, the NRC staff concludes that Entergy has established an acceptable course of action for managing age-related degradation in the Waterford 3 RV internals under the EPU conditions for the unit.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. The NRC staff further concludes that the licensee has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC 1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to reactor internal and core support materials.

Conclusions

The NRC staff has reviewed Entergy's proposed license amendment to increase the rated core thermal power for Waterford 3 by 8 percent and has evaluated the impact that the EPU conditions will have on the structural integrity assessments for the RV and RV internals. The NRC staff has determined that the proposed license amendment will not significantly impact the remaining safety margins required for following RCS-related structural integrity assessments: (1) RV Surveillance Program for the Waterford 3 RV; (2) USE assessment for the RV; (3) P-T limits for the Waterford 3 RV, as proposed in Reference 37, and approved in the NRC staff's SE of June 16, 2004; (4) PTS assessment for the Waterford 3 RV beltline materials; and (5) structural integrity assessment of the Waterford 3 RV internal components, in that the licensee has committed to the establishment of a plant-specific augmented inspection program for the RV internals.

As part of its review, the NRC staff did determine that there was a recent change to the withdrawal schedule for the Waterford 3 RV materials surveillance program as a result of the recent removal and testing of the 263E RV material surveillance capsule. The NRC staff, therefore, included a review of the Waterford 3 RV materials surveillance program withdrawal schedule of Reference 37, as proposed in Table 7-1 of Reference 32. The NRC staff determined that changes to the surveillance capsule withdrawal schedule are consistent with the withdrawal schedule provisions in ASTM E185-82 for a three-capsule withdrawal program, which is the program that is currently applicable to the Waterford 3 RV. The NRC staff also determined that the proposed withdrawal schedule in Table 7-1 of Reference 32, complies with 10 CFR Part 50, Appendix H, and accounts for the impact of the EPU on the surveillance capsule withdrawal times. Based on this evaluation, the NRC staff concludes that RV materials surveillance program is acceptable for the EPU conditions.

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their specifications; compatibility with the reactor coolant, fabrication, and processing; susceptibility to degradation; and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (3) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (4) GDC 31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance is provided in Matrix 1 of Reference 31. Additional review guidance for primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01, Information Notice (IN) 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of CASS components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000.

Technical Evaluation

The licensee stated that during service, the RCPB materials are exposed to a high temperature aqueous environment and applied loads. Prolonged exposures to these conditions may result in changes to the mechanical and corrosion properties of the component materials and may result in age-related degradation of the materials. According to the information provided in the licensee's submittal, the Cycle 14 EPU for Waterford 3 will result in a minimal increase in the nominal hot leg temperature, 0.8 °F, and a 2.0 °F decrease in the cold leg temperature. The ferritic materials were originally procured and tested in accordance with 10 CFR Part 50, Appendix G. The licensee stated that lack of anticipated changes from the planned EPU will have no effect on the hot leg components and are beneficial for the cold leg components with respect to PWSCC of dissimilar weld joints or thermal aging of CASS components. The licensee concluded that, based on the above considerations, changes associated with the EPU are not expected to affect the structural integrity of the RCPB components and all of the RCPB materials will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, Appendix G to 10 CFR Part 50, and 10 CFR 50.55a following implementation of the EPU. While the NRC staff agrees with the licensee's conclusion regarding the RCPB materials after the EPU is implemented, additional information was requested in order to assess the effect of the hot leg temperature increase on Alloy 600 and Alloy 82/182 materials. Although the increase in temperature for EPU conditions at Waterford 3 is very small, 0.8 EF, the NRC staff requested that the licensee provide additional information to that provided in Reference 1 to quantify the effect of the proposed EPU on RCPB components containing Alloys 600/82/182. The NRC staff also requested that the licensee provide an updated list of all RCPB materials because inconsistencies were noted by the NRC staff during its review of the Waterford 3 UFSAR, Tables 5.2-3 and 5.2-4.

By Reference 5, the licensee indicated that, after reviewing its UFSAR Tables 5.2-3 and 5.2-4, it determined that several corrections to material designations were needed. The licensee stated that this issue was entered into the Waterford 3 10 CFR Part 50, Appendix B, corrective action program. The licensee provided corrected tables in Reference 5.

Alloy 600, in combination with NiCrFe weld filler metals (Alloy 82 and 182), are used in nozzle applications at Waterford 3. Applications include pressurizer instrument nozzles and heater sleeves, hot and cold leg RCS piping resistance temperature detector and pressure measurement/sampling nozzles, reactor pressure vessel (RPV) head control element drive mechanisms (CEDM), and incore instrument nozzles and vent line. These applications are associated with partial penetration welds used to attach nozzles to various primary system components. Waterford 3 also contains numerous bi-metallic butt welds in the primary pressure boundary that contain Alloy 82 and or Alloy 182 weld filler metal.

The licensee stated that analysis of available data shows that PWSCC is a thermally activated process that can be described by an expression (time-to-crack), which shows that in the case of Waterford 3, the 0.8 EF increase in hot leg temperature represents a 3 percent decrease in the remaining lifetime of Alloy 600 components exposed to hot leg temperatures. The 2 EF decrease in the cold leg temperature represents an increase in the lifetimes of nozzles and welds of approximately 9 percent. The NRC staff finds this acceptable and concludes that the minor increase in temperature during EPU conditions at Waterford 3 has little or no effect on RCPB materials, based on the information supplied by the licensee in its submittal.

Other materials contained within the RCPB are Alloy 690, and ferritic and stainless steel (cast, wrought and forged) materials. The NRC staff finds that the licensee's conclusion that these materials will not be adversely affected in a significant manner due to the EPU is acceptable.

<u>Summary</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, Appendix G to 10 CFR Part 50, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.6 Leak-Before-Break Evaluation

Regulatory Evaluation

Leak-before-break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures for a piping system. NRC approval of LBB for a plant permits the licensee to (1) remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers) and (2) redesign pipe-connected components, their supports, and their internals. The NRC staff's review for LBB covered (1) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions), (2) indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fires, flooding, missiles, and failures of SSCs in close proximity to the piping), and (3) deterministic fracture mechanics and leak detection methods. The NRC's acceptance criteria for LBB are based on GDC 4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis. Specific review criteria are contained in draft SRP Section 3.6.3 and other guidance provided in Matrix 1 of Reference 31.

Technical Evaluation

The licensee stated that the evaluations documented in Topical Report CEN-367-A (Reference 38) are applicable, considering the revised normal operation loads due to power uprate. According to the licensee, the evaluation confirms that the dynamic effects of postulated main loop pipe breaks can be excluded from the design basis of main loop components, internals, fuel, supports, attachments and appurtenances, and attached piping systems under EPU conditions. Branch line pipe breaks (BLPBs) are required to be considered.

The licensee also stated that each of the criteria for evaluation of compliance with the revised GDC 4 (52 FR 41288) was reviewed for impacts due to power uprate. The loads calculated for the RCS with EPU were evaluated by comparing them to the loads used in the original LBB evaluation. The six LBB compliance criteria from NUREG-1061, Volume III, which were considered and met in Topical Report CEN-367-A (Reference 38), are also met by the EPU. These six criteria are summarized below and compliance with all criteria was found to be unaffected by the EPU.

(1) Loads are considered at locations of highest stress and weakest materials.
(2) The piping system is shown to be resistant to SCC, fatigue, and waterhammer.
(3) Material data from base metal, weldments, and safe ends are considered.
(4) A through-wall flaw is postulated at the highest stressed locations determined from Criterion (1) above.
(5) The postulated leakage flaw is shown to be stable under (normal plus safe shutdown earthquake (SSE)) loads with a margin of 1.4.
(6) The postulated leakage flaw is shown to be stable under 2 x (normal plus SSE) loads.

The NRC staff has reviewed the information submitted by the licensee regarding the potential impact of the proposed Waterford 3 power uprate on the acceptability of the LBB status of the Waterford 3 main coolant loop (MCL) piping. The primary system pressure, primary system temperature, material properties, and design-basis SSE loadings are the parameters that could have a significant impact on the facility's LBB evaluation. However, relative to the margins and assumptions in the existing Waterford 3 LBB analysis, the requested 8 percent power uprate results in minimal changes to these parameters. Therefore, the NRC staff has concluded that the changes to the LBB evaluation for this piping resulting from the proposed power uprate will not alter the previous conclusions associated with Reference 38, demonstrating LBB behavior of the Waterford 3 MCL piping.

Summary

The NRC staff concludes that, per the provisions of GDC 4, the dynamic effects from postulated breaks of the Waterford 3 MCL piping may continue to be excluded from the licensing basis of the facility for post-power uprate conditions. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed EPU, and that lines for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the NRC staff finds the proposed EPU acceptable with respect to LBB.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials, and finds the proposed EPU acceptable with respect to RCPB materials. The NRC staff has also reviewed the licensee's evaluation of the effects of the proposed EPU on LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant accident (LOCA) (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) 10 CFR Part 50, Appendix B, which provides quality assurance requirements for the design, fabrication, and construction of safety-related SSCs; and (2) RG 1.54, Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

Technical Evaluation

The licensee stated that Waterford 3 Service Level 1 coatings in containment were selected and tested to meet design basis accident (DBA) and normal operating conditions. These coatings meet the requirements of American National Standards Institute (ANSI) Standards N5.12, “Protective Coatings (Paints) for the Nuclear Industry,” dated June 20, 1974, and N101.2, “Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities,” dated May 30, 1972. The quality assurance during manufacturing, transportation, and storage is in compliance with ANSI Standard N101.4, “Quality Assurance for Protective Coating Applied to Nuclear Facilities,” dated November 1972, in conjunction with the general quality assurance requirements of ANSI Standard N45.2, “Quality Assurance Program Requirements for Nuclear Power Plants.” The licensee stated that the procurement, application, and maintenance of Service Level 1 protective coatings used inside the containment are consistent with the licensing basis and regulatory requirements. The requirements of 10 CFR Part 50, Appendix B, are implemented through specification and procedures that delineate appropriate technical and quality requirements for the Service Level 1 coatings program, including ongoing maintenance activities. The protective coatings are discussed in UFSAR Section 6.1.2.

The EPU conditions that can affect the qualification of the coatings are changes in pressure, temperature, radiation, and chemistry. The licensee concluded that changes in pressure, temperature, radiation, and chemistry for DBA and normal conditions due to the EPU are bounded by current DBA and normal conditions for these parameters. Consequently, the protective coatings remain qualified for EPU conditions.

On the basis of the NRC staff review, the NRC staff concludes that the protective coating systems are acceptable under the EPU conditions because the current DBA and normal conditions bound the EPU conditions for the pressure, temperature, radiation, and chemistry parameters.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of Appendix B to 10 CFR Part 50. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coating systems.

2.1.8 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from stainless steel are not affected by FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The licensee's FAC program is based on NUREG-1344, GL 89-08, and the guidelines in EPRI Report NSAC-202L-Revision 2 (Reference 39). It consists of predicting loss of material using the CHECWORKS computer code, and visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

The licensee used EPRI's CHECWORKS code to estimate the effects of EPU on components that are susceptible to FAC. The licensee used changes to the plant operating parameters (e.g., increased flow rates, changes in steam quality, temperatures, and pressures) to determine the effects of the EPU conditions on FAC wear rates. The licensee updated the current CHECWORKS model with the EPU conditions for all modeled systems that are susceptible to FAC. The updated model also incorporates all inspection data for calibration of predicted wear rates. This study compared the current predicted wear rates and the post-EPU predicted wear rates of all modeled systems in the FAC program. The systems analyzed are FW, blowdown, HDRs, extraction steam, miscellaneous drains, and condensate drains. The results showed that the FAC wear rates after the EPU will increase by a low to moderate amount.

The licensee stated that during each outage inspections are performed to identify piping in need of replacement. The pipes are repaired to preclude falling below minimum wall thickness. The increase in the FAC wear rate after EPU and consequent reduction in pipe wall thickness will be monitored via the FAC inspection program. The licensee stated that the piping will be replaced if the measured wall thickness at the current RFO and/or the projected wall thickness at the next RFO falls below the ASME Code-allowable wall thickness.

In Question 1 of its Request for Additional Information (RAI) dated January 28, 2004 (ML040330260), the NRC staff asked the licensee to provide a list of the components most susceptible to FAC, including initial wall thickness (nominal), current wall thickness, and the predicted wall thickness. By Reference 3, the licensee provided data of the wear rate on sample piping obtained in the pre- and post-EPU conditions. The data indicate the initial and current wall thickness of the (sample) piping that shows high wear rate and also contain predicted wall thickness of the piping in the current operating conditions and post-uprated conditions.

In Question 2, the NRC staff asked the licensee to provide examples of the piping components for which wall thinning is predicted by CHECWORKS based on the current operating conditions and confirmed measured NDE. The comparison of predicted wall thickness versus measured wall thickness would show the effectiveness of CHECWORKS in prediction. By Reference 3, the licensee submitted a comparison of predicted wall thickness vs. measured wall thickness of sample piping. The data show that the wall thickness prediction by CHECWORKS is conservative. Therefore, the NRC staff finds that the CHECWORKS prediction at Waterford 3 has been demonstrated to be adequate.

In Question 3, the NRC staff asked the licensee to discuss the inspection technique and inspection scope (e.g., how many piping systems are inspected) in the FAC program and specific subsection in the ASME Code by which the minimum wall thickness is calculated.

By Reference 3, the licensee responded that it uses ultrasonic testing as the primary inspection technique for FAC. The following systems are monitored in the FAC program: FW, blowdown, FW HDRs, extraction steam, main steam drain headers, condensate, steam bypass, cross-under pipe, and main steam. The licensee stated that its FAC inspection program is consistent with the recommendations in Reference 39.

The licensee stated further that for wall thinning in piping due to FAC that occurs in a localized region, the decision to replace the piping is based on comparing measured or projected wall thickness at the localized region with the allowable localized wall thickness. The allowable localized wall thickness is the minimum thickness, based on the geometry of the thinned location, calculated by ASME Code proximity criteria equations with allowables for Class 1 piping in ASME subarticle NB-3200. The acceptance criteria in Reference 39 are also based on the ASME Code Class 1 design rules that dictate screening criteria for identifying wall thinning.

The NRC staff's Question 4 asked the licensee to discuss the limit on the percentage of wall thickness below which the pipe is replaced, and discuss whether the pipe replacement due to FAC is consistent with ASME Code, Section XI, Case N597-1, which is referenced in RG 1.147, Revision 13, June 2003; and Reference 39.

By Reference 3, the licensee responded that its piping replacement criteria meet the EPRI Guideline Document (NP-5911SP), which recommends that piping be replaced when measured or projected wall thickness falls below 20 percent of nominal wall thickness. The piping is replaced or repaired when (1) the projected wall thickness is below 30 percent of nominal wall thickness for ASME Class 1 and 2 Piping, (2) the projected wall thickness is below 20 percent of nominal wall thickness for ASME Class 3 piping, and (3) the projected wall thickness is the lesser of 0.3 x nominal and 0.5 x minimum thickness for Class 3 low energy and B31.1 piping.

The licensee stated that the existing piping replacement criteria are consistent with the guidelines in Reference 39, and/or NRC guidance. ASME Section XI, Code Case N597-1, provides the requirements for analytical evaluation of pipe wall thinning. This Code case is supplemented by the provisions in Reference 39, for developing the inspection requirements, the method of predicting the rate of wall thickness loss, and the value of predicted remaining wall thickness. Piping components affected by FAC to which Code Case N597-1 is applied must be repaired or replaced in accordance with the construction Code of record and owner's requirements, or a later NRC-approved edition of Section III of the ASME Code prior to the value of projected wall thickness reaching the allowable minimum wall thickness. The licensee stated that the inspection requirements, the method of predicting the rate of wall thickness loss, and the value of predicted remaining wall thickness meet the guidance in Reference 39.

The licensee compares the measured/projected wall thickness as obtained during the outage to the acceptable minimum wall thickness as discussed above. If the projected wall thickness is below the acceptable minimum wall thickness, the licensee performs a detailed engineering evaluation following a methodology for evaluating localized thinning in piping for ASME Section III, ANSI B31.7, and ANSI B31.1 carbon steel piping.

As discussed with members of the NRC staff on September 2, 2004, the licensee stated in Reference 17 that the heat balance used to assess the impact of EPU on FAC has been revised to incorporate precision pressure measurements for the throttle steam pressure and reheater heating steam pressures. Also, to better bound expected operating conditions, the heat balance has been run at a circulating water temperature of 42 °F, in addition to the circulating water temperature of 92 °F used previously. Running with a low circulating water temperature maximizes extraction steam flow in the low point FW heaters and therefore maximizes flow in the associated HDR lines. As a result, minor impacts may be seen on components enclosed inside the condenser. Therefore, Entergy will update the FAC program with the revised heat balance and reassess the EPU impact on FAC prior to EPU implementation.

By Reference 17, Entergy submitted a commitment (See Section 4.0 of this SE, Commitment 50), which reads: "Entergy will update the FAC program with the revised heat balance and reassess the EPU impact on FAC prior to EPU implementation..." The NRC staff finds the commitment acceptable.

The NRC staff finds that the FAC program is acceptable under the EPU because the program is consistent with the guidance in Reference 39, was demonstrated to be conservative in its application, and the program (i.e., the prediction method) has been adjusted to account for the EPU conditions.

Summary

The NRC staff has reviewed the licensee's evaluation of the effect of the proposed EPU on the FAC analysis for the plant and concludes that the licensee has adequately addressed changes in the plant operating conditions on the FAC analysis. The NRC staff further concludes that the licensee has demonstrated that the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FAC.

2.1.9 Steam Generator Tube Inservice Inspection

Regulatory Evaluation

SG tubes constitute a large part of the RCPB. SG tube inservice inspection (ISI) provides a means for assessing the structural and leaktight integrity of the SG tubes through periodic inspection and testing of critical areas and features of the tubes. The NRC staff's review in this area covered the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed EPU on plugging limits, potential degradation mechanisms (e.g., flow-induced vibration (FIV)), plant-specific alternate repair criteria, and redefined inspection boundaries. The NRC's acceptance criteria for SG tube ISI are based on 10 CFR 50.55a requirements for periodic inspection and testing of the RCPB. Specific review criteria are contained in SRP Section 5.4.2.2 and other guidance provided in Matrix 1 of Reference 31. Additional review guidance is contained in Technical Specification (TS) 3/4.4.4, STEAM GENERATORS, for SG surveillance requirements; RG 1.121 for SG tube plugging limits; GL 95-03; BL 88-02 for degradation mechanisms, structural and leakage performance criteria in

NEI 97-06, "Steam Generator Program Guidelines"; and Topical Reports as applicable, all of which form the basis for alternate repair criteria or redefined inspection boundaries.

Technical Evaluation

The licensee has implemented the guidance of NEI 97-06 at Waterford 3, including degradation prevention, inspection, integrity evaluation, repair, and leakage monitoring of SG tubes. The EPU will result in higher FW flow, temperature changes, and potentially more sludge in the SGs. The EPU can cause an increase in growth rates and initiation of cracking in the SG tubing. The licensee does not anticipate that a new form of degradation will result from the EPU. The licensee, however, anticipates that increased wear at the anti-vibration tube supports could result from changes in the thermal-hydraulics from increased fluid flow in the secondary side of the SGs. The staff concludes that the potential increase in tube wear will be detected and monitored during the licensee's periodic SG tube inspection. Further, the licensee will be taking appropriate action per the plant TS and NEI 97-06.

In accordance with NEI 97-06, the licensee performs the degradation assessment before the SG tube inspections so that the scope and techniques used will address both the identified and potential degradation mechanisms. After the SG tube inspections, the licensee performs an operational assessment to project the integrity of the SG tubes at end of the next cycle. This evaluation accounts for the expected upcoming cycle parameters. Therefore, the evaluation prior to Cycle 14 will account for the changes in temperature on potential crack initiation and growth, and the potential tube leakage. The conditional monitoring and operational assessment will determine the tube integrity at end-of-cycle (EOC), which is compared to the performance criteria for tube burst and leakage.

The licensee stated that implementation of the NEI 97-06 program ensures that changes in the conditions of the SG tubing that are the result of the EPU will be identified and addressed. The licensee concluded that SG tube integrity will continue to be maintained in accordance with NEI 97-06 following the EPU.

In Question 5 of its RAI dated January 28, 2004, the staff requested the basis of the primary-to-secondary operational leakage of 720 gallons per day (gpd) per SG in TS 3.4.5.2 in light of the leakage limit of 150 gallons per day per SG, as recommended in NEI 97-06. By Reference 10, the licensee proposed to revise the primary-to-secondary operational leakage in TS 3.4.5.2 from 720 to 75 gpd per SG. The licensee also proposed to revise Bases pages B 3/4 4-3 and B 3/4 4-4 to reflect the proposed change in TS 3.4.5.2. The NRC staff finds that the proposed changes to TS 3.4.5.2 and associated Bases pages are acceptable because the operational leakage limit of 75 gpd per SG satisfies the leakage limit of 150 gpd per SG as recommended in NEI 97-06.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on SG tube integrity and concludes that the licensee has adequately assessed the continued acceptability of the plant's TSs under the proposed EPU conditions and has identified appropriate degradation management inspections to address the effects of changes in temperature, differential pressure, and flow rates on SG tube integrity. The NRC staff further concludes that the licensee has demonstrated that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06 and the requirements of 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SG tube ISI.

2.1.10 Steam Generator Blowdown System

Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The SG blowdown system (SGBS) provides a means for removing SG secondary-side impurities and, thus, assists in maintaining acceptable secondary-side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected and design flows for all modes of operation. The NRC staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including AOOs (condenser inleakage and primary-to-secondary leakage). The NRC's acceptance criteria for the SGBS are based on GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture. Specific review criteria are contained in SRP Section 10.4.8.

Technical Evaluation

The SGBS is designed to maintain the SG shell side water chemistry by continuous blowdown during normal plant operating conditions; to direct the blowdown to the blowdown demineralizers for treatment; and to achieve and maintain the chemistry requirements of the water inventory in the Condensate and Feedwater Systems (CFWSs) prior to introduction of FW into the SGs during plant start-up and operation. The detailed SGBS is described in UFSAR Section 10.4.8. The licensee examined the effect of the higher FW flow rate due to the EPU on the SGBS.

The licensee stated that typical operational blowdown rates during normal operation are approximately 1 percent of current FW flow. The SGBS is designed to handle 2 percent of the original rated flow or 650 gallons per minute (gpm). Although the FW flow will be increasing as a result of the EPU, the capacity of the SGBS under the EPU conditions will still be adequate to maintain secondary water chemistry in the SGs. The licensee concluded that there are no design basis changes in the SGBS. The SGBS will continue to meet the requirements of GDC 14 and satisfactorily perform the intended functions under the EPU conditions.

In Question 6, the NRC staff asked the licensee to (1) discuss the FW flow increase in the EPU conditions as a percentage of the original rated flow, (2) provide a percentage of the blowdown flow increase in terms of original rated flow, and (3) discuss whether the blowdown demineralizers are adequate to treat the increased blowdown flow rate under the EPU conditions.

By Reference 3, the licensee responded that the FW flow rate will be increased by 7.4 percent after the EPU. However, the blowdown flow is independent of the FW flow and will not be increased after the EPU. The SGBS will be operated within the designed flow range (60 to 425 gpm), which will be within the acceptable flow range to maintain water chemistry parameters for the EPU. In addition, the blowdown demineralizer beds are designed to accept a maximum normal flow rate of 700 gpm each, which is greater than the maximum normal design flow of 425 gpm.

The NRC staff concludes that the SGBS is adequate under the EPU conditions because the blowdown flow will not be increased after the EPU and that the demineralizer beds will have sufficient capacity to treat potential blowdown flow increases to maintain proper secondary water chemistry.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The NRC staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of GDC 14 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SGBS.

2.1.11 Chemical and Volume Control System

Regulatory Evaluation

The CVCS provides a means for (1) maintaining water inventory and quality in the RCS, (2) supplying seal-water flow to the RCPs and pressurizer auxiliary spray, (3) controlling the boron neutron absorber concentration in the reactor coolant, (4) controlling the primary water chemistry and reducing coolant radioactivity level, and (5) supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the ECCS in the event of postulated accidents. The NRC staff reviewed the safety-related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on (1) GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; and (2) GDC 29, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs. Specific review criteria are contained in SRP Section 9.3.4.

Technical Evaluation

The CVCS is described in UFSAR Section 9.3.4 and consists of four basic subsystems: letdown, charging, boron addition, and reactor makeup water. Its primary function is to maintain RCS inventory and control RCS chemistry. Other RCS support functions include serving as a part of the RCS pressure boundary, aiding in containment isolation, providing auxiliary pressurizer spray, and providing for RCP seal bleedoff flow.

The licensee has verified that the CVCS under EPU conditions will maintain its intended function without system modifications. The requirements for the boric acid makeup tank (BAMT) volume and concentration will change. The chemistry and purity of the RCS will be maintained under EPU conditions. Although the EPU will cause an increase in the generation of activity in the RCS, this change is considered to be negligible. The higher power level may necessitate changes to the RCS chemistry requirements, but any changes will be within the capabilities of the CVCS.

The licensee has evaluated the ability of the CVCS to provide the required shutdown margin and found it to be adequate for the EPU. UFSAR Section 9.3.4.3.1 explains that CVCS letdown is not required to achieve cold shutdown. In a cooldown without letdown, the total makeup that can be added to the RCS is limited by the total RCS shrink during cooldown. Because of the core design for the EPU, the minimum required boron concentration in the BAMT will need to be increased. This has necessitated changes to the Waterford 3 TSs. The licensee has submitted the changes to TS 3/4.1.2.8 and associated Figure 3.1-1 in Reference 1. The NRC staff evaluation of the BAMT TS change is discussed in Section 3.0 of this SE.

The licensee states that the analyses related to the effects of the proposed EPU on the CVCS have been reviewed and that the effects of the changes in temperature of the reactor coolant and their effects on the CVCS due to the proposed EPU have been adequately addressed. The licensee concludes that the CVCS will maintain its design function.

Based on its review, the NRC staff concludes that the CVCS will continue to meet the requirements of GDC 14 and GDC 29 following implementation of the proposed EPU.

<u>Summary</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the CVCS, and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS. The NRC staff further concludes that the licensee has demonstrated that the CVCS will continue to be acceptable and will continue to meet the requirements of GDC 14 and GDC 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CVCS.

2.1.12 Water Chemistry Evaluation

The licensee states that the primary and secondary chemistry programs are governed by the Strategic Primary Water Chemistry Plan and Strategic Secondary Water Chemistry Plan, as required by NEI 97-06. The Primary Water Chemistry Program is discussed in UFSAR Section 9.3.4 and Secondary Water Chemistry Program is discussed in UFSAR Section 10.3.5.

The licensee has verified that no revision to the Waterford 3 Strategic Water Chemistry Plan is required as a result of the EPU. The program to control primary water pH with lithium to buffer boric acid does not need to be changed in light of the EPU. The FAC program is updated based on the Secondary Water Chemistry Program, as required. The Secondary Water Chemistry Program, as described in the Strategic Secondary Water Chemistry Plan, is adequate to provide this input to the FAC program, and does not need to be changed in light of the EPU. In addition, the existing Analysis of Record for the mass of trisodium phosphate dodecahydrate required in the containment sump for post-LOCA pH control remains valid, considering the increase in the BAMT as discussed in Section 2.1.11 of this SE. The boric acid inventory assumed in that reference analysis continues to bound the boric acid inventory after the EPU.

In Question 7, the NRC staff asked the licensee to clarify which revisions of the EPRI reports are currently being used for its water chemistry programs and whether procedures are implemented at Waterford 3 to adopt the latest version of the EPRI water chemistry reports.

By Reference 3, the licensee stated that it currently uses Revision 4 of EPRI-TR-105714 and Revision 5 of EPRI TR-102134. EPRI issued Revision 5 to TR-105714 (as EPRI Document No. 1002884) in September 2003, which was scheduled for implementation at Waterford 3 by June 2004. The licensee stated that the current process to adopt the latest EPRI guidance is to generate a condition report documenting the revised EPRI guideline. Any programmatic changes will be identified with scheduled implementation dates.

Summary

On the basis of NRC staff review, the staff concludes that the Primary and Secondary Water Chemistry Programs will be acceptable under the EPU conditions because the licensee has demonstrated that the current primary and secondary water chemistry programs bound any changes under the EPU conditions.

Conclusion

In the areas of SGs and Chemical Engineering, the staff concludes that the licensee has adequately addressed (1) the effects of the proposed EPU on protective coatings, (2) changes in the plant operating conditions on the FAC analysis, (3) the continued acceptability of the plant's TSs under the proposed EPU conditions and the determination that the SG tube integrity will continue to be maintained and will meet the performance criteria in NEI 97-06, (4) the changes in system flow and impurity levels and their effects on the SGBS, (5) the changes of the reactor coolant and their effect on the CVCS, and (6) the acceptability of Primary and Secondary Water Chemistry Programs under EPU conditions.

2.2 Mechanical and Civil Engineering

This section addresses the review of the amendment, as it relates to the effects of the power uprate on the structural and pressure boundary integrity of the Nuclear Steam Supply System (NSSS) and balance-of-plant (BOP) systems. Affected components in these systems include piping, in-line equipment and pipe supports, the reactor pressure vessel (RPV), core support structures, reactor vessel internals (RVI), SG, CEDM, and RCPs and pressurizer. The licensee indicated that Reference 1 contained the plant-specific information that follows the guidance provided in Westinghouse Topical Report, WCAP-10263, “A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant,” January 1993.

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff’s review covered (1) the implementation of criteria for defining pipe break and crack locations and configurations; (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints; (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects; and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed EPU may have on items (1) thru (4) above. The NRC's acceptance criteria are based on GDC 4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

Technical Evaluation

The design basis for the original Waterford 3 RCS piping, components and support systems include postulated breaks in all high energy piping above 1 inch in diameter. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects of MCL breaks (MCLBs) was eliminated. Following the application of LBB technology, the remaining pipe breaks in the design basis of the RCS are all primary and secondary side BLPBs interfacing with the RCS. Of these, the limiting breaks with respect to RCS structural considerations are breaks in the largest tributary pipes: MS line (MSL), FW line (FWL), surge line, safety injection (SI) line, SDC line (SDCL).

The licensee reviewed pipe stresses and fatigue usage factors for the as-built configurations of these piping systems and eliminated many intermediate breaks in these branch lines. The final intermediate breaks in all these piping systems except the surge line were each represented by an envelope set of loads at its RCS nozzle interface. Due to the asymmetry of the Waterford 3 "A" and "B" loops, SI line breaks were postulated off both "A" and "B" loops. All non-negligible intermediate surge line breaks were maintained as separate break cases. The final set of BLPBs postulated and analyzed for RCS response for the EPU consisted of 19 BLPBs, as listed in Table 2.2-1 in Reference 1. For the EPU evaluation, these BLPBs replaced the MCLBs in the original design basis, following elimination of the MCLBs based on LBB technology. The staff finds the licensee's selection of BLPB locations to be in compliance with the provision of SRP Section 3.6.2.

The licensee performed ANSYS dynamic analyses to account for the dynamic effects associated with BLPBs. The loads include the thrust at the break locations, jet impingement loadings at and away from the break locations, RV blowdown loadings for the primary side BLPBs, and asymmetric pressurization loads on the SG and RCPs for all pipe breaks except the MSLB (which does not cause SG sub-compartment pressurization). Jet targets and jet impingement loadings were based on cone jets or fan jets, depending on the break type and break scenario. After elimination of MCLBs by application of LBB, none of the limiting BLPBs for Waterford 3 causes asymmetric pressurization to occur between the RV cavity and the RV shell. The staff finds the licensee's analysis methodology associated with the break locations and the associated dynamic effects of BLPBs to be adequate and acceptable based on SRP Section 3.9.3.

Summary

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects, and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the Section III, Division 1 of the Code, and GDCs 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered (1) the analyses of FIV, and (2) the analytical methodologies, assumptions, Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and cumulative usage factors (CUFs) against the Code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes, combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided Reference 31.

Technical Evaluation

Nuclear Steam Supply System Piping, Components, and Supports

The licensee evaluated the NSSS piping and supports by reviewing the design basis analysis against the uprated power condition, with regard to the design system parameters, transients, and the LOCA dynamic loads. The evaluation was performed for the MCL, RCS tributary lines, and the pressurizer surge line piping systems. The methods, criteria, and requirements used in the existing design basis analysis, as specified in the Waterford 3 UFSAR, are applicable for the power uprate evaluation.

The design basis for the original Waterford 3 RCS piping, components, and support systems included postulated breaks in all high energy piping above 1 inch in diameter. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects of MCLBs was eliminated. Following the application of LBB, the remaining pipe breaks in the design basis of the RCS are all primary and secondary side BLPBs interfacing with the RCS. Of these, the limiting breaks with respect to RCS structural considerations are breaks in the largest tributary pipes: MSL, FWL, surge line, SI line, and SDCL. The postulated and analyzed BLPBs for RCS response consisted of nozzle terminal end breaks and the line intermediate breaks, as listed in Table 2.2-1 of Reference 1.

For the analysis at the EPU condition, the licensee constructed a three-dimensional ANSYS model of the entire RCS pressure boundary that includes Waterford 3 plant-specific main loop piping, components, RV and internals, SG and RCP, their supports, current fuel and the updated closure head lift rig (CHLR) and CEDM configurations. The ANSYS computer code was used to perform the dynamic time history analyses due to the BLPBs. The licensee indicated in Reference 7 that the only changes between the original RCS analysis and the EPU analysis were that (1) the original RCS mathematical model was converted from the STRUDL computer code format to the ANSYS code input format, and (2) the pipe break loadings were based on BLPBs at EPU conditions instead of on MCLBs at pre-uprate conditions. The modal superposition method with 3 percent of the critical damping applied at each mode is used in the dynamic analysis, which is consistent with the damping used in the Waterford 3 design basis for the RCS systems. The resultant stresses for the RCS main coolant loop piping for the hot and cold legs are determined as shown in Table 2.2-5 of the request submittal. The calculated stresses and CUFs are less than the code-allowable limits and are, therefore, acceptable.

The licensee also indicated that for the hot leg piping at the uprated power condition, its assessment showed no change in the analysis of record (AOR) CUF of 0.382, which is the highest value in the main coolant piping accounting for the holes associated with the installation of a mechanical nozzle seal assembly (MNSA) on the hot leg straight pipe, and the subsequent reduction in the pipe thickness. In its response to the staff's RAI regarding whether the installed MNSA is permanent at Waterford 3, the licensee indicated that MNSAs had been installed on the hot leg in RFO 9, but were removed in RFO 10. The licensee also indicated that MNSAs are now authorized for installation at Waterford 3 only on pressurizer instrument nozzles and pressurizer heater sleeves for a maximum of two operating cycles during the current inspection interval for Waterford 3. The AOR conditions are bounding for the EPU conditions at the hot leg and pressurizer. Therefore, the current AOR loads on MNSAs remain valid for the power uprate.

The licensee evaluated the surge line considering the thermal stratification transients. The most significant stratification transients occur during plant heat-up and cool-down. Less significant thermal stratification events that occur during normal plant operation were also considered by the licensee. Since the temperatures during heat-up and cool-down were not affected by the power uprate, the previous design basis transient results for the surge line remain unchanged. The licensee also indicated that (1) the original thermal anchor movements at the surge line nozzles did not change due to the power uprate, (2) the surge line nozzle deadweight and thermal loads from the original design basis remain unchanged, and (3) the original seismic analysis for the surge line is not affected by the power uprate. The licensee also evaluated the surge line to a LOCA load due to the effects of the five major BLPSs. The calculated stresses and CUFs provided in Table 2.2-21 of Reference 1 are less than the allowable limits. The Code and Code edition used for the pressurizer surge line is the 1974 Edition of the Code, up to and including the Summer 1975 Addenda, which is the Code of record.

The RCS tributary lines were analyzed to address the changes resulting from the power uprate. The licensee performed the dynamic analyses of the RCS model, using ANSYS computer code, subjected to the thrust at the break locations, jet impingement loadings at and away from the break locations, and RV blowdown loadings for the primary side BLPBs. For the MSLs and FWLs (Code Class 2 piping) inside containment, the analyses were performed in compliance with requirements of Section III, 1971 Edition of the Code, up to and including the Winter 1972

Addenda, which is the Code of record. For Class 1 piping in the SI, SDC, and pressurizer spray lines, Section III, NB-3600, of the 1974 Edition of the Code, including addenda through the Summer 1975 addenda, is the Code of record. Tables 2.2-13 to 2.2-22 of Reference 1 provide calculated maximum stresses, fatigue usage factors, and code-allowable limits for the Class 1 piping of the SI, SDC, charging and letdown, auxiliary spray, and pressurizer spray lines. Tables 2.2-23 to 2.2-26 of Reference 1 provide calculated maximum stresses and code-allowable limits for the MS and FW piping, which are Class 2 piping and do not require a fatigue analysis. The staff finds the maximum calculated stresses and CUFs to be less than the code-allowable limits and, therefore, acceptable.

The results from the ANSYS dynamic analysis for the RCS system include loads on the major components, nozzles, and supports of the RCS for the normal operating condition and the faulted LOCA conditions due to BLPBs. These loads were used in the evaluations of the SG, RCP, and RV nozzles and their supports, as well as MCL piping and the RCP motor. Response displacement and acceleration time histories and acceleration response spectra were generated at the surge line nozzle interface, branch line RCS nozzle interfaces and the RV shell (at the upper head, closure flange, and core support barrel (CSB) snubber elevations). The resultant stresses and CUFs on the main loop piping tributary nozzles (i.e., SI, charging inlet nozzle, hot leg drain, cold leg letdown/drain, surge, SDC, and spray), summarized in Table 2.2-6 and 2.2-7 of Reference 1, are less than the code-allowable limits. In Reference 7, the licensee provided the resultant stresses and CUFs in the RV and major component supports in the tables on pages 12 to 17 of 29. The tabulated stresses and CUFs are within the Code-allowable limits, and are, therefore, acceptable.

On the basis of its review of the licensee’s submittal, the staff finds that the licensee’s conclusion that the existing NSSS piping and supports, the primary equipment nozzles, the primary equipment supports, and the tributary lines connecting to the main loop piping will remain in compliance with the requirements of the design bases criteria, as defined in the Waterford 3 UFSAR, acceptable for the proposed power uprate.

Balance-of-Plant Piping, Components, and Supports

The licensee evaluated essential BOP piping systems to assess the impact of the various changes due to uprate and/or due to new BLPB LOCA, thermal stratification, and transient loadings for the CVCS charging and letdown lines. Besides the RCS piping on the primary side, the four SI, the two SDC, the surge, the pressurizer spray, and the CVCS charging/letdown/auxiliary spray piping runs were evaluated. Two MS and two FW piping runs on the secondary side were also evaluated. Maximum calculated stresses and CUFs for the evaluated BOP piping systems are provided in Reference 1. In Reference 7, the licensee indicated that the evaluation for the power uprate was based on the requirements of (1) ASME Code, Section III, 1974 Edition, including addenda through Summer 1975, for Class I Piping; (2) ASME Code, Section III, 1971 Edition, including addenda through Winter 1972 for Class 2 and 3 Piping; and (3) ANSI B31.1 Code, 1973 Edition for Non-Safety/Non-Seismic Piping. The above cited standards represent the Code of record for the Waterford 3 BOP piping. The calculated stresses and CUFs provided are within the Code-allowable limits and are, therefore, acceptable.

With regard to the effects of the increased steam flow in the secondary system due to the power uprate, the licensee indicated that piping qualification is not specifically performed for effects of vibration due to fluid flow. To ensure that changes resulting from the EPU do not cause excessive vibration that could be detrimental to system performance, vibration monitoring will be performed following the EPU to identify sources of vibrations and appropriate corrective actions to be taken to eliminate or minimize these vibrations. The EPU represents an incremental change in flow in the MSLs and FWLs, which could increase the vibration level of the piping system. Essential piping within these two systems is currently being monitored using pipe mounted instruments at strategic locations to obtain baseline data for determining future changes in vibration characteristics. Following implementation of the EPU, these locations will continue to be monitored to identify areas with potentially significant changes in vibratory behavior. At Waterford 3, the licensee will also monitor accessible branch connections off the MSLs and FWLs outside containment for vibration. Vibration data will be collected at the final power plateau (100 percent) as part of power ascension testing. The licensee also indicated that review of the data will be completed in time to support submittal of the Startup Test Report (within 90 days following startup). In Reference 1, the licensee stated that vibration monitoring and evaluation of the measured data will be in accordance with ASME Operations and Maintenance (OM), Part 3, "Operations and Maintenance of Nuclear Power Plants," and the acceptance criteria provided in ASME OM, Part 3, would be utilized. Compensatory and corrective actions would be taken, where required, to comply with the specified limits.

The licensee evaluated pipe supports such as snubbers, hangers, struts, anchorages, equipment nozzles, guides, and penetrations by evaluating the piping interface loads due to the increases in pressure, temperature, and flow for the affected limiting piping systems. The increase in pipe support loads due to the power uprate conditions is consistent with the increase in piping stresses. However, when combining these increases with the loads such as seismic and deadweight, which are not affected by the power uprate, the overall combined support load increases are generally insignificant. The licensee indicated that, as a result of the evaluation, there are very few and minor modifications to the piping supports due to the power uprate. For instance, the analysis of affected portions of the CCW system return piping downstream of the SDC heat exchangers was determined to be exceeding the design temperature as a result of the EPU during normal plant shutdown. As such, the licensee committed to evaluate the impact of these higher temperatures for the CCW piping, supports, and components, as well as the impact of these higher temperatures on the SDC heat exchanger room cooler. The licensee asserted that appropriate actions will be taken as necessary, based on the results of this evaluation. In Attachment 8 to Reference 1, the licensee committed to complete these actions by the end of RFO13 (i.e., prior to operating at EPU conditions).

In Reference 7, the licensee indicated that the evaluation of CCW piping and pipe supports would be completed by August 3, 2004. However, in Attachment 3 to Reference 13, the licensee indicated that it determined that the CCW system return piping downstream of the SDC heat exchanger could exceed and has exceeded the design temperature at the current (pre-EPU) power level during normal shutdowns and, therefore, has entered this issue into its 10 CFR 50 Appendix B corrective action program. The licensee also indicated that, due to the increase in scope, this issue can not be resolved prior to EPU implementation in the spring of 2005. The licensee also indicated that, currently, a compensatory action is in place that requires operators to monitor and maintain the CCW return line temperature from the SDC outlet header to less than or equal to 225 ^{o}F. The CCW piping, pipe supports, and components in the line were evaluated at 225 ^{o}F and found acceptable. In Reference 18, the licensee described evaluations that were performed for the CCW SDC heat exchanger outlet piping, pipe supports, and components to support continued operation. These evaluations determined that the system will remain operable with a CCW SDC heat exchanger outlet temperature up to 225 °F. The licensee also noted that the compensatory action is currently incorporated into the plant operating procedures. In Reference 13, the licensee committed to review the existing compensatory measures and ensure that such measures are adequate to maintain operability following power uprate. Thus, the compensatory measures will have to be updated as appropriate to ensure the return line temperature operability limit of 225 °F is not exceeded. The licensee committed to complete this action prior to the implementation of the EPU.

As a result of the above evaluation, the staff concludes that BOP piping, pipe supports, and equipment nozzles will remain acceptable and continue to satisfy the design-basis requirements for the power uprate (excluding the CCW SDC heat exchanger outlet piping and pipe supports). The CCW SDC heat exchanger outlet piping and pipe supports will remain operable for the power uprate, upon satisfactory implementation of the compensatory measures.

Reactor Vessel and Supports

The licensee evaluated the RV for the effects of the revised design conditions provided in Table 1-2 of Reference 1 for the core power level of 3716 MWt. The evaluation was performed for the limiting vessel locations with regard to stresses and CUFs in each of the regions, as identified in the RV stress reports for the core power uprated conditions. The regions of the RV affected by the power uprate include the RPV (main closure head flange, studs, and vessel flange), CEDM housing, outlet nozzles and supports, inlet nozzles and supports, vessel wall transition, core support pads, bottom head-to-shell juncture, instrumentation tubes, and head adapter plugs. In Reference 1, the licensee indicated that the evaluation of the RV was performed in accordance with the Section III, 1971 Edition of the Code with Addenda through the Summer of 1971. The results indicate that the maximum primary plus secondary stresses for all the RV critical locations other than the CEDM housing are within the Code-allowable limits. The CEDM housing is evaluated separately following this section. For all locations, the licensee indicated that the maximum stress intensity and the primary membrane plus bending stress in the AOR were found to remain valid for the power uprate following the application of the LBB technology. The licensee concluded that the stresses and CUFs for the RV critical locations remain below the allowable ASME Code limits.

On the basis of its review, the staff finds acceptable the licensee's conclusion that the current design of the RV continues to be in compliance with the licensing basis codes for the proposed power uprate condition.

Control Element Drive Mechanism

The pressure boundary portions of the CEDM are those exposed to the vessel/core inlet fluid. The CEDMs are affected by the reactor coolant pressure, the vessel outlet temperature, and the NSSS design transients. The licensee evaluated the adequacy of the CEDMs by reviewing the Waterford 3 original AOR. The evaluation was performed in compliance with the requirements of Section III, "Nuclear Vessels" of the 1971 Edition of the Code, up to and including the 1973 Summer Addenda, which is the Code of record.

On the basis of its evaluation, the licensee determined that the transient conditions for the power uprate are unchanged from the original design basis in the AOR. The number of transient occurrences is not changed for the power uprate. The reactor coolant pressure remains unchanged for the proposed power uprate. The vessel outlet temperature at the power uprate is 601 °F, which is below the current design basis temperature value of 611 °F. There is no change in the vessel head operating temperatures in the vicinity of the CEDM nozzles.

For the power uprate analysis, the licensee constructed an ANSYS analysis model for CEDMs. The model includes CEDMs and the CHLR to account for the interaction between the CEDMs and the CHLR under pipe break conditions. The analysis was performed to determine the response of CEDMs to the BLPB using the ANSYS computer code. The calculated stresses for critical CEDM components and nozzles are provided in Table 2.2-12 of Reference 1. The resultant stresses are within the code-allowable limits. Therefore, the licensee concluded that there is no impact on the CEDMs due to the power uprate conditions.

On the basis of its review above, the staff finds the licensee's conclusion that the CEDMs will maintain the structural and pressure integrity for the proposed power uprate acceptable.

Steam Generators and Supports

The licensee evaluated the structural integrity of SG components for the increase in the reactor core power by 8 percent above the current power level of 3441 MWt. The evaluation was based on the ANSYS analysis for the LOCA loads due to the current licensing basis BLPBs at the power uprate conditions. The seismic and dead weight loads are not affected by the power uprate and remain unchanged from the AOR. The thermal expansion loads due to the power uprate condition were obtained from the ANSYS analysis results. The SG components include steam outlet nozzles, FW nozzles, SG skirt support, sliding base and bearings, and the SG internals. The SG internal components evaluated are baffle and baffle supports, FW sparger and support bracket, steam dryer supports, tubes, and tube supports.

The licensee indicated that the Code and Code edition used in the evaluation of SGs for the power uprate is the 1971 Edition of the ASME Code, Section III, "Nuclear Vessel," up to and including the 1971 Summer Addenda, which is the Code of record. The licensee also indicated that, in general, evaluation of the SG internals addressed loads resulting from dead weight and seismic conditions, as well as secondary flow and thermal conditions (where applicable). Since the secondary system internals are not part of the ASME pressure boundary, analysis for cyclic operation in NB-3222.4(d) is not required. For certain components (e.g., FW sparger), as required, the fatigue usage factors were calculated to meet the ASME Code-allowable limit of 1.0. In Reference 7, the licensee provided a summary of the maximum calculated stresses in the SG secondary internal components. The staff finds that these stresses and CUFs are less than the code-allowable limits and are, therefore, acceptable.

The licensee evaluated the SG supports for the effects of the EPU. The SG upper supports include the snubber arrangements and the bracket and bolts. The SG lower supports include the support skirt, the sliding base, snubber lug, and shear keys. The existing snubber supports were evaluated based on the AOR using the 1977 Edition of the ASME Code. The support skirt was evaluated based on the 1971 edition of ASME Section III, up to and including the Summer 1971 Addenda. The code used for evaluation of the SG sliding base was the 1974 edition of the ASME Code, Section III, through the 1975 Winter Addenda, which is the Code of record. In Reference 7, the licensee provided the maximum calculated stresses for the SG upper support snubber assembly, the support skirt and shear keys, and the lower support sliding base and bolts for the power uprate. The calculated stresses are less than the Code-allowable limits and are, therefore, acceptable.

The licensee also evaluated the effects of the 8 percent power uprate on the potential for the flow-induced vibration and the design basis fatigue analysis for the U-bend tubes. The evaluation of flow-induced vibration for the proposed power uprate conditions are summarized in Section 2.2.2.1.4.6.3 of Reference 1. The licensee indicated that pre-uprate evaluations of the tube and tube supports are based on design parameters that are bounding for the EPU. The flow-induced vibrations due to either flow turbulence or vortex shedding are very small and the governing peak stress less than the endurance limit. With regard to the fluid elastic instability, the licensee calculated the maximum stability ratio to be 0.8 for the tubes. This is less than the code-allowable limit of 1.0. Therefore, the licensee concluded that the proposed power uprate does not increase the potential for flow-induced vibration for the SG tubes.

In response to the staff's RAI regarding the effects of higher flow rate on the steam dryer at the EPU condition, the licensee provided a comparison of operating parameters including steam flow rates across the dryers and the steam dynamic pressures between Palo Verde and Waterford 3, since these two CE plants have the same steam dryer design. The dryer design and analytical and operating experience documented at Palo Verde demonstrate that the dryers and dryer supports will remain adequate to sustain the flow-induced vibration for a steam flow of 8.5 Mlb/hr in comparison to the Waterford 3 steam flow of 8.23 Mlb/hr. Palo Verde is operating at 3816 MWt, which is greater than the proposed Waterford 3 EPU power level of 3716 MWt. The steam dynamic pressure at the Palo Verde dryer is also higher than at Waterford 3. In addition, the database shows that the Palo Verde Unit 1 steam dryers have been operating for nearly 20 years with no failure record. The licensee estimated stress at the dryer support for the power uprate to be less than 12 ksi, which is below the endurance limit of 13.6 ksi and, therefore, acceptable.

On the basis of its review, the staff finds the licensee's conclusion that the current SGs at Waterford 3 will continue to maintain their structural and pressure boundary integrity and remain in compliance with the Code of record specified in the UFSAR acceptable for the proposed 8 percent power uprate.

Reactor Coolant Pumps and Supports

The licensee reviewed the existing design basis analyses of the Waterford 3 RCPs, which are affected by the revised design conditions in Table 1-2 of Reference 1, the operating transients, and the dynamic effects of current design basis branch line breaks. The critical components affected by the EPU include pump casing volute, boss, lower and upper flanges, RCP closure shear keys, key slots and bolts, and RCP support columns, clevises and base plate. The licensee indicated that the evaluation was performed in accordance with the requirements of the ASME Code, Section III, 1971 Edition, with the Winter 1971 Addenda, which is the Code of record. The RCP support components are evaluated in compliance with ASME Section III, 1974 Edition through 1975 Winter Addenda.

Due to the elimination of MCLBs through the application of LBB technology, the design basis of the postulated pipe breaks analyzed under power uprate conditions were BLPBs. The faulted LOCA loads and load combinations used in the AOR for pre-uprate conditions are controlling for power uprate, because the AOR evaluated the RCP components for specified MCLB loads, which envelop the BLPB loads calculated for EPU, and for specified SSE loads, which are not affected by the EPU. Critical components under upset conditions were shown to be acceptable for the EPU by demonstrating that the set of upset (normal operation plus operating basis earthquake (OBE)) loads that had previously been specified for pre-uprate conditions and used in the RCP component AOR envelop the upset loads for EPU. This is because the previously specified OBE loads contain a large margin over as-calculated OBE loads for Waterford 3.

After the core power uprate, the RCS pressure remains unchanged. However, the components of the RCP are affected by increases in loads due to RCS thermal expansion and temperature differences under EPU conditions. The critical locations affected include the casing in the areas of the volute, boss, lower flange and upper flange elements, and the closure parts such as shear keys and bolts. The maximum stresses for the RCP limiting components shown in Tables 2.2-3 and 2.2-4 of Reference 1 are within the Code-allowable limits. Also, there are no significant changes to the design thermal transients. The licensee determined that the effect of EPU on the limiting CUF margins for the RCP components is insignificant. Other components, such as the RCP heat exchanger and the RCP motor and flywheel, are not affected by the EPU conditions because the specific pressure loads and thermal conditions have not changed due to the EPU.

The licensee also evaluated the RCP supports for EPU for changes in loads due to RCS thermal expansion and BLPBs. In Reference 7, the licensee provided the calculated resultant stresses for the RCP support limiting components. The staff finds that the provided stresses and CUFs are within the Code-allowable limits and are, therefore, acceptable.

Pressurizer and Supports

The licensee evaluated the structural adequacy of the pressurizer and components for operation at the uprated conditions. The evaluation was performed by comparing the key parameters in the current design basis Waterford 3 pressurizer stress report against the revised design conditions in Tables 1-2 of Reference 1 for the proposed power uprate.

The licensee's evaluation indicated that the design and operating temperatures of the pressurizer and its thermal movements are not affected by the proposed power uprate. Minor changes in the MCL piping T_{hot} and T_{cold} values due to the power uprate did not change the thermal anchor movements either at the hot leg/surge line interface, or along the surge line up to the surge line pressurizer nozzle interface. Also, the design temperature condition (653 ^oF) affecting thermal expansion of the pressurizer enveloped the power uprate conditions. Since the design basis transient conditions were not affected, the original thermal analyses remain bounding. Therefore, the original design basis pressurizer loads and motions remain valid for the proposed power uprate.

In Reference 7, the licensee presented the evaluation of the pressurizer for the power uprate conditions to account for the dynamic effects on the pressurizer components due to branch pipe breaks in the pressurizer spray line, the safety valve line A, the safety valve line B, and the surge line. The Code and Code edition used for the evaluation is the 1971 Edition of the ASME Code, up to and including the Summer 1971 Addenda, which is the Code of record. The licensee provided the calculated stresses and cumulative fatigue usage factors for the limiting pressurizer components and support skirt at the proposed power uprate condition. The staff finds that the calculated stresses and CUFs for limiting pressurizer locations at the uprated condition are less than the code-allowable limits and are, therefore, acceptable.

Summary

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC 1, 2, 4, 14, and 15 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

RPV internals (RPVI) consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and non-safety-related reactor internal components, and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of Reference 31.

Technical Evaluation

The licensee evaluated the effect of the power uprate on the RPVI in Section 2.2.3 of Reference 1. The RPVIs evaluated for the proposed power uprate comprise both core support and internal structures. Core support structures, which provide direct support/restraint of the reactor core, include the lower support structure, CSB, and upper guide structure (UGS) components. Internal structures, which do not provide direct support/restraint of the reactor core, include the core shroud assembly, the in-core instrument supports, the alignment keys, and the holddown ring. The RVI supports within the RV provide a uniform distribution of coolant among the fuel assemblies, maintain the reactor core in a coolable geometry, provide and maintain a free path for the insertion of CEAs into the reactor core, and protect the CEAs and in-core instrument hardware from coolant crossflow.

In its evaluation, the licensee reviewed the effects of revised thermal, hydraulic, mechanical and pipe break input data due to power uprate on the existing analysis for the normal operating plus upset condition (Level A+B) and faulted conditions (Level D) documented in the existing AOR for the Waterford 3 RPVI. The licensee's structural analysis included the current fuel assembly design and mass, and modeling refinements to the pipe break analyses due to the use of LBB methodology.

The licensee performed Level A + B evaluations in accordance with the criteria of Section III, Subsection NG, 1973 draft and of the ASME Code, respectively, as defined in the Waterford 3 SAR, Section 3.9.5.4.1 and Table 3.9-13. The licensee evaluated Level D stresses based on the requirements of Section III, Appendix F of the ASME Code (introduced in the Winter 1972 Addendum), per Section 3.9.5.4.1 and Table 3.9-13 of the Waterford 3 UFSAR. In the evaluation of RPVI components where the revised data were encompassed by the AOR, the AOR was retained as-is, and where the revised data are more limiting than that used in the AOR, the stresses were recalculated using the AOR methodology and revised data.

The results of the licensee's evaluation are summarized in Table 2.2-27, Reference 1, in the form of structural margins. Stress intensities in the RPVI components resulting from the incorporation of revised input loads associated with EPU were shown less than the Code-allowable limits for both normal-operating plus upset and faulted design conditions. Cumulative fatigue usage was shown to be less than 1.0 for the RVI components. The licensee concluded that the RPVI components will continue to satisfy the Code-allowable limits for the normal operating, upset, and faulted design conditions. The staff finds the licensee's conclusion that the RPVI will retain the structural integrity at the power uprate condition acceptable.

The impact of the revised hydraulic data on the hold-down ring's capability to provide adequate core barrel and UGS hold-down force was also evaluated. The licensee indicated that the allowable hold-down ring rocking and sliding margins are engineering judgement, based on operating experience with numerous plants. The separate allowable margins determined for normal operating and transient conditions provide a sufficiently conservative hold-down force to prevent rocking and sliding of the CSB and UGS assemblies. In addition, the calculation of the hydraulic loads used in the evaluation is based on conservative assumptions. The evaluation shows that the hold-down force applied by the ring meets the established allowable margins.

In Reference 1, the licensee indicated that flow-induced vibration is caused by the application of dynamic hydraulic loads. These dynamic loads are associated with pump pulsation and random turbulence. Hydraulic load input to the RPVI structural evaluation included both static and dynamic loads, and the resulting RPVI structural margins summarized in Table 2.2-27 of Reference 1, therefore, reflect the application of flow-induced vibration loads. These flow-induced vibration loads also affect high-cycle (i.e, $>10^6$ cycles) fatigue usage. At the time of the AOR, high-cycle fatigue curves were not included in the ASME Code, and high-cycle fatigue evaluations were not, and are not, required by the Waterford 3 UFSAR. For the power uprate, high-cycle fatigue of RPVI components was addressed via a scoping evaluation, which used the high-cycle fatigue curves from current ASME Code editions to demonstrate that high-cycle fatigue usage would be acceptable for Waterford 3 RPVI components. Low-cycle (i.e. $<10^6$ cycles) fatigue was addressed by demonstrating that the peak alternating stress required to achieve maximum allowable fatigue usage was greater than that calculated for any of the RPVI components.

Based on its review of the licensee's evaluation of the effect of the power uprate on the RPVI structural analysis and integrity, the staff concludes that the licensee's evaluation has adequately demonstrated that the RPVI will safely withstand the normal operating plus upset and faulted conditions.

Summary

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC 1, 2, 4, and 10 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the design of the reactor internal and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Code and within the scope of Section XI of the ASME Code and the ASME OM Code, as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 37, 40, 43, and 46, insofar as they require that the ECCS, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC 54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section meet the inservice testing program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6; and other guidance provided in Matrix 2 of Reference 31.

Technical Evaluation

As discussed in References 1 and 7, the licensee evaluated the effect of the requested power uprate on the functionality of safety-related pumps and valves at Waterford 3. In considering the licensee's power uprate request, the NRC staff reviewed the licensee's submittals (with examples of valve evaluations), and discussed the potential effect of the power uprate on safety-related pumps and valves in telephone conferences with the licensee on April 6 and September 22, 2004. For example, the performance and TS requirements for safety-related pumps will be maintained at Waterford 3 for power uprate operation. The licensee evaluated the potential effect of the power uprate on valves in the motor-operated, air-operated, and hydraulic-operated valve programs at Waterford 3. The licensee previously evaluated safety-related MOVs in response to GL 89-10. In a letter dated December 21, 1994 (9412290277), the NRC informed the licensee that it had completed the detailed review of the GL 89-10 program at Waterford 3 through plant inspections and review of licensee submittals. In a letter dated August 27, 2000 (ML003709351), the NRC accepted the licensee's MOV program in response to GL 96-05, through review of submitted information. In evaluating the potential impact of the power uprate at Waterford 3, the licensee determined that the maximum expected differential pressure assumed in the setup calculations for gate and globe valves will not increase for power uprate operation. Similarly, the licensee determined that the design flow rate assumed in the setup calculations for butterfly valves will accommodate the system flow rates that might occur during power uprate operation. In addition, the minimal increase in ambient temperature that might result from power uprate operation is not expected to adversely impact the motor output for MOV performance. Further, no adverse effects were identified regarding safety and relief valves in light of the absence of changes in their performance requirements. The licensee also evaluated the potential impact of the power uprate on its response to GL 95-07. The licensee determined that the scope of the GL 95-07 response, and the modifications and analyses previously performed, remain valid for the power uprate conditions in light of minimal changes in performance requirements and ambient temperature conditions for the power-operated gate valves at Waterford 3. The NRC staff finds the licensee's evaluation of the effect of the proposed power uprate on the capability of safety-related pumps and valves at Waterford 3 to be acceptable, based on the staff's previous review of the licensee's programs in response to GLs 89-10, 95-07, and 96-05; and the current review of the information submitted by the licensee describing the scope, extent, and results of the evaluation of safety-related pumps and valves at Waterford 3.

Summary

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related power-operated valves. Based on this, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC 1, 37, 40, 43, 46, and 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. The primary input motions due to the SSE are not affected by an EPU. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets QA requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

Due to the elimination of MCLBs through the application of LBB technology, the design basis of the postulated pipe breaks analyzed under power uprate conditions were BLPBs, as listed in Section 2.2.1.1 of Reference 1, consisting of nozzle and intermediate breaks in MSL, FWL, surge line, SI line, and SDCL. The dynamic effects on the equipment due to a LOCA are not affected by the EPU analysis. In addition, the design basis seismic analysis is not affected by the EPU and, therefore, the seismic qualification of essential equipment remains unchanged. The licensee also evaluated the effects of the EPU on the analysis of high energy and moderate energy line breaks. The evaluated high energy lines included the MS, FW, SG blowdown, and CVCS. The licensee indicated that there are no new HELB locations due to the power uprate. As a result, the licensee concluded that the design basis analyses of pipe-whip and jet impingement are not affected by the proposed power uprate. On the basis of its review, the staff finds acceptable the licensee's conclusion that the current design basis analyses for the seismic and dynamic qualification of safety related equipment remain unchanged for the proposed power uprate.

Summary

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment, and concludes that the licensee has (1) adequately addressed the effects of the proposed EPU on this equipment, and (2) demonstrated that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30, 10 CFR Part 100, Appendix A; and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

The term "environmental qualification" (EQ) applies to equipment that must remain functional during and following design basis events (DBEs). The NRC staff's review covers the environmental conditions which could affect the design and safety functions of electrical equipment, including instrumentation and control. The NRC staff's review verifies compliance with the acceptance criteria, thus ensuring that the equipment continues to be capable of performing its design safety functions under all normal environmental conditions, AOOs, and accident and post-accident environmental conditions. Acceptance criteria are based on 10 CFR 50.49 as it relates to specific requirements regarding the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

Impact on the EQ Program from the EPU includes potential changes in the containment LOCA/main steam-line break (LOCA/MSLB) temperature and pressure EQ profile, containment radiological conditions (both normal and accident), auxiliary building radiological conditions during accident conditions, and high-energy line breaks (HELBs).

Containment Accident Conditions

The current plant accident profile for electrical EQ equipment located in containment will change for the EPU conditions. While the peak pressures and temperatures at the EPU conditions are bounded by the current pressure and temperature EQ plant accident profile, the time at elevated temperatures at EPU conditions is slightly longer. Analysis performed demonstrates that the electrical EQ equipment located inside containment remains qualified. There will be no changes to the containment spray (CS) chemical content for the uprate. The total integrated radiation dose used for qualification of safety-related electrical equipment inside the containment is the sum of the 40-year normal exposure plus the radiation during and following the most severe DBEs for which the equipment must remain functional. To evaluate the impact of the power uprate on normal doses, calculations were performed that compared the normal operating doses from containment sources due to power uprate source terms with doses resulting from current design basis source terms. In all cases evaluated, the doses calculated using the power uprate source terms were bounded by the doses using the current design basis source terms. This is primarily due to use of the newer ANSI 18.1 standard for the source term in place of ANSI N237, and use of the updated ANSI 6.1.1, 1991 flux-to-dose conversion factors in place of the older 1977 version of that standard. The post-accident containment doses were compared with the doses based on the current design basis source terms. For all cases evaluated, the doses calculated using the power uprate source terms were bounded by the doses using the current design basis source terms.

The containment flood level was not changed. The submergence level remains the same and, as such, the EQ components at the lower levels are not affected by the EPU.

High-Energy Line Breaks

Since the MS and FW systems are located outside the reactor auxiliary building (RAB) structure, the environmental conditions produced by the pipe breaks in these systems will not affect any safety-related equipment or components. The response to NUREG-588 justifies that there are no HELBs outside containment that need to be evaluated at Waterford 3. The EPU does not invalidate this conclusion.

Radiological Conditions – Reactor Auxiliary Building

The normal 40-year total integrated dose for qualification of safety-related electrical equipment was evaluated by comparing the containment source dose based on the power uprate normal operating source terms with the dose resulting from use of the design basis normal source term, or that currently specified for EQ zones. For all cases evaluated, the power uprate case was bounded by the design basis case. Post-accident radiological conditions in the RAB were also evaluated for the power uprate. The airborne dose in the RAB is due to containment leakage and Engineered Safety Feature (ESF) leakage. The 120-day post-accident dose from these sources using the power uprate core inventory was compared with the dose using the current design basis core source term. The evaluation showed that the total airborne dose using the power uprate source term was bounded by the airborne dose using the design basis source term.

Summary

The NRC staff has reviewed the licensee's submittal on the effects of the proposed power uprate on the environmental qualification of the electrical equipment and concludes that EQ equipment remains qualified and will continue to meet the requirements of 10 CFR 50.49 for the power uprate.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covers the information, analyses, and documents for the offsite power system and the stability studies for the electrical transmission grid. The focus of the review relates to the basic requirement that the loss of the nuclear unit, the largest operating unit on the grid, or the loss of the most critical transmission line will not result in the loss of offsite power (LOOP) to the plant. Branch

Technical Position Instrumentation and Control System Branch (BTP ICSB)-11, “Stability of Offsite Power Systems,” outlines an acceptable approach to addressing the issue of stability of offsite power systems. Acceptance criteria are based on GDC 17 of Appendix A to 10 CFR Part 50. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to 8.2 and BTPs Power System Branch (PSB)-1 and ICSB-11.

Technical Evaluation

Grid Stability

The transmission system in the vicinity of the Waterford 3 switchyard was analyzed for single contingency (loss of Waterford 3, loss of largest generating unit, or loss of the most critical transmission line) to ensure that the grid system remains stable for the uprated power level at Waterford 3. Increasing the power level does not result in instability of the Waterford 3 unit for the disturbances (faults or other single contingency events) expected on the transmission system. Offsite power systems will return to equilibrium without cascading trips of additional transmission lines, generators, or other transmission equipment after these disturbances. Additionally, during such disturbances, the offsite system will continue to supply the safety-related buses with acceptable voltage levels (per National Electric Manufacturer's Association (NEMA) standards) so motors can start and perform their required safety function. Entergy performed a grid system analysis to support the proposed power increase. The steady-state analysis confirmed that the Waterford 3 switchyard voltage levels during summer peak conditions following a loss of the most critical transmission line, or any large surrounding generating unit, are acceptable. A generated output for the station was assumed that bounds the Waterford 3 power uprate. The dynamic analysis indicated that a three-phase fault near the Waterford 3 230 kilo volt (kV) switchyard results in the Waterford 3 unit and the system remaining stable for both existing and power uprate generation levels. The analysis supported the conclusion that there is insignificant impact on grid stability and reliability for the power uprate. The NRC staff was concerned about the depletion of megavolt-amperes reactives (MVARs) with the power uprate and asked the licensee to address the compensatory measures that the licensee would take to address the depletion of the nuclear unit MVAR capability on a grid-wide basis. By Reference 4, the licensee responded that no compensatory measures are postulated post-power uprate. The pre-uprate nominal generator output is 1153 MW. The generator reactive output existing administrative limit is 400 MVAR, which results in a power factor of 0.954. The post-uprate nominal generator output will be 1231 MW. The generator reactive output capability will be 512 MVAR at a power factor of 0.927. The administrative limit will be kept at 400 MVAR. The grid stability studies have demonstrated that for power uprate, the transmission grid remains stable. These studies evaluated the increased grid injection from Waterford 3 to ensure system stability criteria are met and to ensure that the offsite voltage remains above 0.97 per unit under various transmission contingencies while Waterford 3 is off-line (post-trip voltages). The transmission technical system planning group also performs studies on a regular basis to ensure compliance with North American Electric Reliability Council (NERC) planning criteria. These studies assumed an overexcited reactive capability of 400 MVAR (to match administrative limit) from the Waterford 3 generator. Moreover, the Waterford 3 unit is located in an area containing a large amount of generation. Therefore, any adverse impact on the transmission system due to the deletion of its MVAR is not likely due to the administrative limit imposed on the Waterford 3 generator.

In conclusion, the grid stability studies have demonstrated that, for the power uprate, the transmission grid remains stable. The power uprate will not adversely impact the availability of the offsite power source for Waterford 3 house loads in the event of a unit trip. Safety-related buses will be supplied by the offsite power sources following postulated transmission system disturbances. Therefore, Waterford 3 continues to be in conformance with GDC 17 for the power uprated electrical conditions.

Main Generator

The main generator is rated at 1333.2 MVA at a 0.9 power factor (60 psi hydrogen pressure). The pre-uprate nominal generator output is 1153 MW and the generator is operating below its rating due to poor performance of the winding. The main generator is being rewound to restore it to its original design rating (i.e., 1333.2 MVA) which can accommodate EPU conditions.

The NRC staff reviewed the licensee's submittal and determined that the main generator will be acceptable for EPU conditions after being rewound.

Main Transformers

The Waterford 3 main transformers consist of 2 three-phase units, each rated at 600 MVA (with 4 of 5 cooling pump/fan units in service), and 798 MVA (with additional external cooling connected) connected in parallel to the main generator output.

The licensee evaluated the equipment for EPU conditions. At this time, the licensee plans to add additional cooling to main transformer 'B' and replace main transformer 'A' in order to support EPU. The main transformers are being modified to support the full 1333.2 MVA generator post-uprate conditions.

The NRC staff reviewed the licensee's submittal and determined that the main transformers will be acceptable for EPU conditions after being modified.

Unit Auxiliary Transformers

The function of the two unit auxiliary transformers is to provide power from the main generator output stepped down to 4.16kV and 6.9kV to the alternating current (AC) electrical distribution system during normal power operations. The unit auxiliary transformers are three-phase transformers having an overall capacity of 52 MVA with a capacity of 32 MVA on the 6900 volt (V) winding, and a capacity of 20 MVA on the 4160V winding.

The equipment has been evaluated for EPU conditions. The unit auxiliary transformer loading bounds anticipated load increases due to the EPU and is, therefore, acceptable.

Startup Transformers

The function of the two startup transformers (SUTs) is to supply offsite power stepped down to 4.16kV and 6.9kV to the AC electrical distribution system during plant startup and shutdown when the main generator is not available. The SUTs are the preferred source of power for accident mitigation. The two SUTs are three-phase transformers having an overall capacity of 56 MVA with the 6900V winding rated at 36 MVA, and with the 4160V winding rated at 20 MVA.

The equipment has been evaluated for EPU conditions. The SUT loading bounds anticipated load increases due to the EPU and is, therefore, acceptable.

Plant Load Changes for Power Uprate Evaluation

Normal loads are supplied via the unit auxiliary and SUTs. These loads are classified by voltage levels: 6900V, 4160V, and 480V. An alkalizer skid will be added as part of the main generator rewind project to address main generator stator cooling water chemistry concerns. This skid and plant modification for the main transformers will add load to the non-vital portion of the 480V AC system and will be addressed within the modification process. No other new loads at these voltage levels are being installed for the EPU. The licensee's evaluation determined that there are minor increases in the 6900V motor loads due to increased demands on the condensate pumps and the RCPs. Additionally, the 4160V motor loads will increase due to HDR pump performance requirements. These increases are well within the transformers' capabilities. No load increases other than those identified above are anticipated on the 480V system due to the power uprate.

The increased loading due to the condensate pumps, RCPs, and HDR pumps is bounded by the load values assumed in plant load and degraded voltage relay setpoint evaluations and is, therefore, acceptable.

Iso-Phase Bus and Bus Duct

The function of the iso-phase bus (IPB) is to conduct power from the main generator to the main and unit auxiliary transformers. The buses are individually enclosed in isolated phase bus ducts and routed to the main and unit auxiliary transformers. The buses are highly conductive hollow aluminum conductors, insulated and enclosed within an isolating duct, which utilize a forced air cooling system. The EPU will increase IPB current and result in more heat generated from the bus due to increased I^2R losses. The IPB and bus ducts were evaluated for EPU conditions and found to be within the system's existing capacity and are, therefore, acceptable.

Generator Output Breakers

The main generator output breakers consist of three individual phase breakers, operated as a single breaker, located in the switching station. The function of these breakers is to electrically connect the output of the main transformers to the 230kV switchyard. Due to the EPU, the existing breakers' continuous load and short circuit interrupting ratings will be exceeded, as well as the associated mechanical disconnect switches on either side of each breaker. New breakers and disconnects are required to meet 1333 MVA and will be installed over RFO12 and RFO13. The design will be acceptable after the installation of the new breakers before the initiation of the EPU.

The NRC staff reviewed the licensee's submittal and determined that the main generator output breakers and the associated mechanical disconnect switches will be acceptable for EPU conditions after being modified.

Summary

The NRC staff has reviewed the licensee's submittal for the effect of the proposed power uprate on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed modifications for the power uprate. The NRC staff further concludes that the impact of the proposed power uprate on grid stability is insignificant. Therefore, the NRC staff finds the proposed power uprate will be acceptable following implementation of the proposed modifications with respect to the offsite power system.

2.3.3 Alternating Current Onsite Power System

Regulatory Evaluation

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to the safety-related equipment. The NRC staff's review covers the descriptive information, analyses, and referenced documents for the AC onsite power system. Acceptance criteria are based on GDC 17 as it relates to the capability of the AC onsite power system to perform its intended functions during all plant operating and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The safety-related buses associated with the AC onsite power system provide reliable power for safe shutdown of the plant during normal and emergency conditions when preferred power is unavailable in either the 'A' or 'B' division. This system is supplied power via the emergency diesel generators (EDGs) to enable safe shutdown of the plant. The safety-related functions are performed through Division A and Division B of this system. Additionally, this system powers selected non-safety-related loads during start-up, normal, and emergency operation of the plant. The EPU will result in negligible changes in 4160V motor loads including non-safety loads. The sequencing of the safety loads is unchanged. No load increases are anticipated on the 480V or 208/120V safety-related low voltage distribution systems due to the power uprate.

Summary

There are negligible load changes to the safety-related buses and EDGs due to the EPU. The onsite power system will continue to meet the requirements of GDC 17. The engineered safeguard loads have not changed. The capacity of each EDG is adequate to support the operation of required engineered safeguards under DBA conditions. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the onsite AC power system.

2.3.4 Direct Current Onsite Power System

Regulatory Evaluation

The direct current (DC) power systems include those DC power sources and their distribution systems and auxiliary supporting systems provided to supply motive or control power to safety-related equipment. The NRC staff's review covers the information, analyses, and referenced documents for the DC onsite power system. Acceptance criteria are based on GDC 17 and 10 CFR 50.63 as they relate to the capability of the DC onsite electrical power to facilitate the functioning of SSCs important to safety. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

Technical Evaluation

The safety-related function of the DC onsite power system is to provide reliable continuous 125V DC power to the plant protection system and other loads for safe operation of the reactor. This system also furnishes power for a safe shutdown of the plant during normal and emergency conditions. Should an accident occur and the preferred power be lost in either or both divisions, this system acts as a source of power for safety-related DC loads and static uninterruptible power supplies until emergency power is available. The non-safety related function of the system is to power the non-safety-related loads required to ensure instrumentation and control capability to monitor and maintain the plant status during startup, shutdown, normal, and emergency plant operation. A plant modification associated with the atmospheric dump valve (ADV) controls required for the EPU will result in a slight increase in DC system loading. No other changes are expected to affect component operation or battery duty cycles due to the EPU.

Summary

The 125V DC distribution system will continue to function as designed. Adequate separation exists, and the system has the capability to continue to supply adequate power to both safety and non-safety equipment. The system will continue to meet the requirements of GDC 17 following implementation of the EPU.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to the complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves LOOP concurrent with turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from alternate AC sources. The NRC staff’s review focused on the impact of the proposed power uprate on the plant’s ability to cope with and recover from an SBO event, as based on 10 CFR 50.63. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP 8.2.

Technical Evaluation

SBO encompasses the complete loss-of-offsite electric power, concurrent with a turbine trip and failure of the onsite emergency AC power system. Plant equipment power from the DC onsite power system and steam from the SGs will be used to remove decay heat from the reactor core. The turbine-driven emergency FW system (EFWS) pump, the ADVs, and DC electric power from Class 1E batteries are available for reactor core decay heat removal (DHR) during the assumed 4-hour event. The turbine-driven pump draws water from the condensate storage pool (CSP) and pumps it into the SGs. Steam from the SGs is used for operating the pump's turbine. The batteries provide electric power to the steam supply valves and the EFWS flow control valves. The suction lines to the turbine-driven pump are aligned to the CSP. The ADVs are used for bleeding steam from the SGs. Decay heat from the reactor core is removed by feeding and bleeding the SGs. Approximately 82,200 gallons of water is needed to remove decay heat for 4 hours in accordance with Nuclear Management and Resources Council (NUMARC) methodology, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC 87-00, November 1987. The CSP has a TS limit of 170,000 gallons of water dedicated for EFWS usage. The turbine-driven EFWS pump has the capability of pumping the required flow to the two SGs during SBO. The Class 1E batteries have sufficient power to meet SBO needs for 4 hours. Air-operated valves (AOVs) needed to control EFWS flow to the SGs are provided with backup nitrogen accumulators. The accumulators have sufficient gas capacity for 10 hours of operation. The ambient air temperature for the turbine-driven EFWS pump area is not expected to rise above 90 °F for SBO. This temperature is below the threshold value of 120 °F for dominant areas of concern requiring equipment operability analysis.

Summary

The EFWS, in conjunction with the ADVs and Class 1E batteries following EPU, is capable of maintaining the RCS in a hot standby condition and removing the decay heat during the 4-hour coping period for SBO. Therefore, the EFWS and supporting systems and components will continue to meet the requirements of 10 CFR 50.63 for the power uprate.

2.3.6 Three-Second Time Delay Between Steam Generator Tube Rupture and Loss-of-Offsite Power

Introduction

In Section 2.13.6.3.2.3 of Reference 1, Entergy states that the steam generator tube rupture (SGTR) analysis assumes that a LOOP occurs 3.0 seconds after the reactor trip. The licensee states that this is a conservative assumption as discussed in CE letter (LD-82-040) to Darrell G. Eisenhut, Director, Division of Licensing, U.S. NRC, dated March 31, 1982. This delay had previously been approved for the RCP locked rotor event on the basis of an analysis of the Florida electrical grid provided in that CE letter. This evaluation addresses the LOOP assumptions for the SGTR scenario.

Regulatory Evaluation

GDC 17 specifies that an onsite electric power system be provided to permit functioning of structures, systems, and components important to safety following AOOs and postulated accidents. GDC 17 requires this capability for the onsite electric power system, assuming the offsite electric power system is not functioning, but does not specify how the offsite power system could be lost.

Technical Evaluation

Entergy assumed a 3-second time delay for a LOOP following a reactor trip in the Waterford 3 SGTR analysis. This delay had previously been approved for the RCP locked rotor event on the basis of a 1982 Florida grid study. The event analyzed was a large-scale, grid-wide breakup event due to the loss of the Waterford 3 generation support (plant trip) as a consequence of the RCP locked rotor event. Such a grid event is a significant occurrence that results in the formation of electrical islands isolated from the rest of the grid and one another. These islands may or may not have enough remaining generation to support adequate and stable frequency and voltages to the customer loads in the island. If automatic and transmission system operator manual load shedding fails to quickly restore adequate frequency and voltage by properly balancing generation and load, a LOOP can occur.

An example of a large-scale, grid-wide breakup event in which electrical islands were formed is the recent August 14, 2003, U.S.-Canadian blackout. These are relatively rare events. The NRC and nuclear power industry generally believed in the late 1970's and early 1980's that, if a nuclear plant trip were to result in a LOOP, the grid breakup due to the loss of the nuclear plant generation would likely be the cause. This belief may have been based on a Florida grid isolation event that occurred in the late 1970's. Subsequent NRC analysis of operational experience for SBO and more recently for the risk-informed 10 CFR 50.46 initiative, however, has found that LOOPs due to a nuclear plant trip are much more likely to occur as the result of localized problems occurring in and around the nuclear plant. Although the August 14, 2003, Blackout Report to the President indicates that, if nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience, the staff believes that, for the nuclear-plant-trip-initiated consequential LOOP, the localized events will continue to dominate. This belief is based upon the response of electrical stakeholders to correct the initiating elements of the August 14, 2003, blackout and the historically large number of localized consequential LOOPs as compared to large-scale grid consequential LOOPs (nine localized nuclear-plant-trip-initiated consequential LOOP events were found over the years 1986 thru 1999, while the staff is not aware of a nuclear plant trip ever causing a large-scale grid LOOP).

Another important consideration in evaluating the expansion of the LOOP assumptions used for the RCP locked rotor event to include the SGTR event is that the SGTR event includes actuation of ECCS loads, while the locked rotor event does not. The mechanisms that could result in a LOOP due to a plant trip, therefore, are not necessarily the same for the RCP electrical buses, as compared to the ECCS electrical buses. One difference in particular is the use of degraded voltage protection on the ECCS electrical buses that is not found on RCP electrical buses.

As a result of the above, the staff requested Entergy to provide an evaluation of the Waterford 3 plant-specific design features that justify the use of the chosen time delay for the consequential LOOP. The staff asked that the following possibilities that could result in a consequential LOOP be addressed for the Waterford 3 site-specific electrical design: degraded switchyard voltage, spurious switchyard breaker-failure-protection circuit actuation, automatic bus transfer failure, and startup transformer failure.

Entergy responded to this RAI in Reference 29. Information provided in the response indicates that spurious actuation of switchyard breaker failure protection circuitry, automatic bus transfer failure, or a startup transformer failure could result in a loss of one startup transformer circuit and the corresponding 6.9kV bus (two RCPs) and one 4.16kV safety bus at Waterford 3, but would not result in a total LOOP. In addition, because these occurrences would likely be linked to the separation of the Waterford 3 generator from the grid, the half LOOP described would occur with an approximate 7 second time delay from the reactor/turbine trip of Waterford 3.

Entergy provided information indicating that the Waterford 3 generator is separated from the grid by a reverse power relay that has been found to actuate at approximately 7 seconds following a turbine trip.

Because the SGTR event involves the actuation of the ECCS, the staff asked Entergy to evaluate the consequences of the delayed LOOP on the performance of the electrical ECCS systems. The staff indicated that the consequences of double sequencing and its associated vulnerabilities that would occur as the result of the delayed LOOP should be a part of this evaluation. These vulnerabilities include, but are not necessarily limited to: the consequences of starting large continuous-duty motors twice in quick succession, with the first start under degraded voltage conditions and the second start with pump discharge valves open; the adequacy of the existing control logic to start loads on offsite power, shed those loads following the LOOP, and subsequently sequence those loads on the EDGs with necessary delay to allow motor residual voltage to decay; interaction between the double sequencing and circuit breaker anti-pump logic that could lock out the breakers; the capability of the safety batteries to operate the necessary systems during an initial offsite power degraded voltage ECCS start, and subsequently restart the ECCS on EDGs; and the potential to trip motor overload protection or blow fuses as a result of a degraded voltage / double sequencing (DV/DS) scenario.

Entergy responded to this RAI in References 29 and 70. Reference 29 described how the Waterford 3 control logic would function if the safety injection actuation signal (SIAS) associated with a SGTR were to occur following a LOOP and how it would function if the LOOP were to occur following the SIAS. For the LOOP delayed SIAS scenario the EDGs are started on the LOOP signal and the LOOP loads are subsequently sequenced onto the EDGs. When the SIAS occurs, the sequencer is reset with a 2-second time delay and additional ECCS loads are sequenced on as necessary. In the event that SIAS is concurrent with a large load starting during the LOOP-initiated EDG start, there will be a 2 second delay for the sequencer to reset and 1.5 second delay before the first large motor (HPSI) starts. Each EDG also has adequate capacity to start and accelerate the largest single load out of sequence, with all other loads running. This provides additional assurance that loads can be started on an EDG if there is minor overlap in the loading sequence.

For the SIAS degraded voltage / delayed LOOP SGTR scenario, information provided by Entergy indicates that following the SIAS, the EDGs are started and run in standby with the output breakers open. The load sequencer resets 2 seconds following the SIAS, and the ECCS loads begin sequencing onto offsite power 3.5 seconds following the SIAS. The degraded voltage relays actuate due to the start of the HPSI pump at 3.5 seconds and, 12.5 seconds later, the relays time-out and safety related buses are separated from offsite power, non-essential loads are isolated, and the sequencer resets. Approximately 5 seconds later, the EDG output breaker closes and the sequencer starts, with the HPSI motor re-starting approximately 1.5 seconds following sequencer start. The staff finds that Entergy’s description of the Waterford 3 control logic indicates it will function as necessary to power safety equipment during these SGTR scenarios and is, therefore, acceptable.

Entergy provided information on the susceptibility of circuit breaker anti-pump logic to lock out a safety-related circuit breaker due to interaction with control logic during this scenario. Entergy indicates that spring charging of the Waterford 3 HPSI breaker (the most limiting breaker) takes approximately 3 seconds and occurs following closing of the circuit breaker. If a trip and subsequent re-close signal were to come in during this period, the breaker would not close and the anti-pump relay would energize and seal in, preventing further breaker closing attempts. Entergy analyzed the DV/DS scenario for this vulnerability in Reference 29, and found that about 19 seconds would elapse between initial breaker closure for SIAS and the second breaker closure for sequencing on the EDG. This provides sufficient time for the spring charging to complete its cycle and the associated limit switches to close to preclude lockout of the circuit breaker. The staff concerns on this topic are, therefore, resolved.

Because batteries were not necessarily sized in consideration of the double sequencing scenario that could occur as a result of a degraded voltage / delayed LOOP SGTR event, the staff asked Entergy to evaluate this capability. Entergy responses indicate that the safety-related batteries at Waterford 3 are sized for peak DC loads for 1 minute. For the SGTR event discussed above (SIAS followed by LOOP), Entergy states that the batteries carry DC loads for less than 1 minute, including ramp up time for the battery chargers. The ramp up time is expected to be less than 20 seconds, based on information that Entergy received from C&D Technologies, Inc., manufacturer of Waterford 3 battery chargers. This evaluation demonstrates that the existing battery calculation is bounding for the DV/DS scenario and resolves the staff question on this item.

With regard to motor starting capability during a DV/DS scenario, Entergy's responses evaluated 4kV motor starting capability on offsite power with the 4.16 kV buses at 90 percent bus voltage. This value allows for voltage reduction due to SIAS loading and motor starting below the 93.1 percent setting of the degraded voltage relays on the safety buses. Entergy indicates that the HPSI, LPSI, ACCW, and emergency feedwater (EFW) pumps could be subject to double sequencing if a LOOP should occur subsequent to the initiation of a SIAS. Entergy states that the concern with starting and running motors at degraded voltage conditions is that the motors may overheat and adversely affect qualified life. The Entergy evaluation identifies a number of design margins available on the HPSI, LPSI, ACCW, and EFW 4kV motors. It concludes that, considering the available design margins (i.e., minus 10 percent of rated voltage, 10 percent additional thermal capacity for difference in altitude, an increase in thermal capacity due to lower starting ambient temperature, and service factor), the increase in motor current for 12.5 seconds (time delay of degraded voltage relay at 93.1 percent) at approximately 90 percent voltage condition, coupled with two consecutive starts (first start at 90 percent bus voltage and second start on the EDG), will not cause any damage to the HPSI, LPSI, ACCW, and EFW motors, nor adversely affect their qualified life.

With regard to 460V motor starting capability during a DV/DS scenario, Entergy responses identify a large number of 460V motors that may be subject to double sequencing due to cycling on and off by a process signal or SIAS. With the first offsite power start at 90 percent voltage on the 4.16kV buses, the 460V motors will be operating below the 90 percent voltage starting capability specified in motor manufactures' standard NEMA MG-1. Entergy has evaluated these motors and concludes that, based on NEMA MG-1 Sections 12.48 and 12.49 and available design margins (i.e., minus 10 percent of rated voltage, 10 percent additional thermal capacity for differences in altitude, an increase in thermal capacity due to lower starting ambient temperature, and service factor for some motors), as described in the 4000V motor discussion, it is reasonable to conclude that the increase in motor current for 12.5 seconds due to degraded voltage condition, coupled with two consecutive starts, will not cause any damage to the 460V AC motors.

There is some support in the literature for Entergy's statement that the concern with starting and running motors at degraded voltage conditions is that the motors may overheat and adversely affect qualified life. NEMA MG-1, Section 20.43.2 states: "It should be recognized that the number of starts should be kept to a minimum since the life of the motor is affected by the number of starts." Institute of Electrical and Electronics Engineers (IEEE) Standard C37.96-2000, *IEEE Guide for AC Motor Protection*, Section 5.2.1 states; "It should be noted that deriving increased output at the price of higher temperatures for any given motor means accepting a shorter life." Volume 6, page 6-56 of the EPRI *Power Plant Electrical Reference Series* states: "Rotor overheating is often far more damaging than stator heating during starting or stalling. Rotors may be weakened so as to fail sooner than they otherwise would have, but no instantaneous melting like that of a fuse element is to be expected under any kind of starting abuse."

Although, as indicated above, there is evidence that starting motors outside of their specified requirements is a fatigue mechanism that can shorten their life rather than an immediate failure concern, this is not explicitly addressed in the standards. Also, a fatigue mechanism motor failure is strongly dependent on the operating and maintenance history of the motor as well as design margins. Consideration could be given to evidence that safety-related motors in nuclear power plant applications are generally well-maintained and some, such as injection pump motors, have minimal operating duty. These are the kinds of variables that a motor supplier could take into account in determining whether a limited endorsement is appropriate for motor starting and operation in a DV/DS scenario such as addressed in this evaluation.

Because some motors at Waterford 3 will be operating outside their specified requirements during the SGTR degraded voltage / double energization scenario, the staff believes it is necessary for Entergy to be aware of conditions that could place Waterford 3 in such a condition if an SGTR were to occur. This can be accomplished through a communication protocol and agreement between Waterford 3 and its transmission system operator (Entergy Transmission) to notify Waterford 3 when a trip of Waterford 3 will result in post-trip switchyard voltages that are inadequate to support a SGTR event at Waterford 3. At present, periodic studies are generally performed for Waterford 3 on a two-year period to project that transmission system voltages will remain adequate for Waterford 3 over the upcoming period. Entergy also told the staff that daily studies are performed for the next day using daily cases representing that day of the month. These studies are updated during the following day if transmission system elements that could affect Waterford 3 post-trip voltages are lost. If a situation is encountered that would result in inadequate switchyard post-trip voltages, Entergy indicates that the Waterford 3 operator will be made aware of the condition. In Reference 71, Entergy committed to formalize these arrangements with Entergy Transmission by June 15, 2005. The agreement also contains an element to verify that the resultant switchyard voltages subsequent to any Waterford 3 reactor trip bound the same voltages predicted by the load flow analysis program (or the real time contingency monitoring program when implemented).

Entergy indicated to the staff that it is currently pursuing changes to the real-time contingency analysis (RTCA) program software used by Entergy Transmission to enable it to perform post-trip analysis considering the specific voltage requirements of Waterford 3. The staff supports this initiative because RTCA programs provide more immediate updates (generally in the range of 5 to 30 minutes or faster) of grid conditions that can affect a nuclear power plant such as contingency post-trip voltages, and they eliminate most of the human decision-making process of when to perform these updates. Entergy committed in its February 5, 2005, letter to update the NRC staff regarding the status/capabilities of the RTCA program by September 30, 2005. If the RTCA program is used to perform post-trip analysis considering the specific voltage requirements of Waterford 3, Entergy also committed to perform an operability assessment of the offsite power sources upon becoming aware that the program is unavailable.

If the RTCA program cannot be used to perform post-trip analysis, Entergy has committed to obtain a motor manufacturer's endorsement or industry (e.g., industry expert) endorsement of Entergy's analysis results regarding proper operation of the Waterford 3 safety-related motors (relied upon during the SGTR event) subject to DV/DS conditions. This will be completed by October 20, 2006. Entergy has indicated that Waterford 3 currently has a good deal of voltage support in the transmission system surrounding the plant, and the surrounding grid is primarily limited by the thermal limits of the transmission network rather than the voltage profiles in the system. This provides good assurance in the near term that the transmission system voltages surrounding Waterford 3 will be adequate. However, the Waterford 3 current operating license will not expire for another 20 years. The character and make-up of the grid surrounding Waterford 3 could change substantially over this period of time. The staff, therefore, believes the commitment to utilize the RTCA program for monitoring of Waterford 3 post-trip voltages or provide an independent endorsement of Entergy's Waterford 3 analysis results is important to monitor the long term safety of the plant relative to an SGTR DV/DS event.

Tripping of motor overload protection is also a concern during a DV/DS scenario. Motor overload protection with thermal memory capability can cause a premature trip due to the two successive starts associated with the DV/DS scenario, because the residual heating associated with the first start can reduce the overload trip time for the second start. Entergy's responses indicate that there is no overload protection with thermal memory capability installed on safety-related 4kV-rated motors at Waterford 3. Entergy also states that the thermal overload relays (one type of overload protection with thermal memory capability) for safety-related motor operated valves are bypassed to prevent tripping when an ESF actuation signal is present. The thermal overload relays for other safety-related 480V motor control center (MCC) fed motors, however, are not bypassed at Waterford 3.

Entergy evaluated the thermal overload protection for the safety-related 480V MCC fed motors. It selected a typical motor based on its voltage, duty cycle, and application. The motor selected was a 460V diesel generator room exhaust fan. A fan was chosen, since fans typically have higher moments of inertia than pumps and correspondingly longer acceleration times. Entergy plotted the calculated motor starting curve against thermal overload protection curves from several manufacturers since it could not obtain the actual manufacturer curves for Waterford 3. It stated that the results show that the energy generated during the double sequencing event is not sufficient to trip the thermal overloads modeled. It also stated that, in general, most overload relays of this size have a typical minimum clearing time of 7 to 8 seconds at 630 percent full load current and, with a cumulative acceleration time of 3.57 seconds for two back to back starts during the double sequencing scenario postulated, the motor could remain at locked rotor current for the entire start sequence and not result in an overload trip.

The staff questioned Entergy about the seemingly very short starting time used for the fan modeled. Entergy indicated that it used the moment of inertia provided for the actual fan in the calculation of the starting time and believed the short starting time was due to the aluminum construction of the fan. It indicated that this was the bounding 460V motor load for thermal overload, DV/DS purposes. The staff believes that whether motor thermal overload protection will trip under a DV/DS scenario can be difficult to predict, since it is dependent on a number of variables, including the length of the motor starting time, ambient temperature of the thermal overload, and elapsed time between motor starts. If the sum of the two motor starting times under a DV/DS start, considering the worst case starting voltages, is less than the minimum clearing time of the thermal overload for a current that is equal to the locked rotor current of the motor, this should be reasonable evidence that the motor will not trip. Entergy's evaluation of the safety-related thermal overloads at Waterford 3 indicates that this is the case. The staff finds that this, together with Entergy's commitments discussed previously, provides reasonable assurance that the safety of the plant will be maintained relative to an SGTR DV/DS event.

During a DV/DS scenario, large continuous-duty pump motors could be called upon to start twice in quick succession, with the first start under degraded voltage conditions, and the second start with the pump discharge valves in the open position. The second start with the discharge valves in the open position could result in a larger demand on the pump motor during its second start than what it was designed for, if the motor was selected with the assumption that discharge valves would be initially closed or partially open during motor start (assumed single start). This might result in tripping of motor overload protection or degradation and failure of the motor. The staff asked Entergy to evaluate this potential for the Waterford 3 plant. Entergy evaluated the HPSI pump, LPSI pump, CCW pump, ACCW water pump, containment spray pump, EFW pump, essential chiller compressor motor, chilled water pump, CCW makeup pump, and boric acid pump for operation with discharge valves in the open position. The licensee's evaluation found that starting of this equipment with the outlet valves in the fully open position is within the normal design configuration, or the motor specifications specified that the motors be sized such that the motor can accelerate with fully open valves. The staff finds that these results adequately resolve the staff questions on this concern.

The licensee made the following commitments in Reference 71:

> The notification of the grid conditions between Entergy Transmission and Waterford 3, regarding grid conditions that could adversely impact Waterford 3 post-trip off-site voltage, will be formalized by 15 June 2005. The agreement will contain/address the following elements: (One Time Action; Scheduled Completion Date: June 15, 2005)
>
> a. Daily Model Load Flow studies (using off-line software such as PTI/PSSE (Power System Simulator for Engineering)) will be performed for the next day using daily cases representing that day of the month. If any transmission contingencies with respect to an element directly interconnected with the Waterford 230 kV switchyard occur during the day, the analyses will be updated. (Continuing Compliance, until real time monitor is implemented.)
> b. Upon becoming aware that grid analyses (i.e., Load Flow analysis or real time contingency monitoring program when instituted) indicate unacceptable post-trip voltages for Waterford 3, Waterford 3 will be made aware of the postulated condition(s). (Continuing Compliance)
> c. Subsequent to any Waterford 3 reactor trip, the resultant switchyard voltages will be verified to be bounded by the same voltages predicted by the Load Flow analysis program (or the real time contingency monitoring program when implemented) under the same conditions. (Continuing Compliance)

d. If a real time contingency monitoring program is used to perform post-trip analysis considering specific voltage requirements of Waterford 3, the Transmission Operator will notify Waterford 3 when the program is unavailable or Waterford 3 will verify the that the program is available (at least weekly). (Continuing Compliance, once real time monitor is implemented.)

Entergy is currently pursuing programming changes to the real-time contingency analysis software to perform post-trip analysis considering specific voltage requirements of Waterford 3. Entergy will update the NRC staff regarding the status/capabilities of the real time contingency monitoring program by September 30, 2005, following testing planned for the summer of 2005. (One Time Action; Scheduled Completion Date: September 30, 2005)

If the real time contingency monitoring program cannot be used to perform post-trip analysis considering specific voltage requirements of Waterford 3: (One Time Action; Scheduled Completion Date: October 20, 2006)

a. Entergy will obtain a motor manufacturer's endorsement or industry (e.g., industry expert) endorsement of Entergy's analysis results regarding proper operation of the Waterford 3 safety related motors (relied upon during the steam generator tube rupture event) subject to degraded voltage / double sequencing conditions. The scenario shall be initiated at the setpoint of the degraded voltage relays.
b. This will be completed by October 20, 2006.

If the real time contingency monitoring program is used to perform post-trip analysis considering specific voltage requirements of Waterford 3, upon becoming aware that the program is unavailable, Waterford 3 will perform an operability assessment of the offsite power sources. (Continuing Compliance, once real time monitor is implemented.)

Summary

The staff concludes that there will be at least a 3-second delay before a consequential LOOP occurs following a reactor trip due to a SGTR event at Waterford 3. The staff also concludes that the realistic consequential LOOPs evaluated by Entergy at the staff's request are acceptable from the electrical equipment operability perspective, given that Entergy implements the commitments on transmission grid communications capabilities identified in its February 5, 2005, letter.

2.3.7 Implementation

The licensee has committed to the following plant modifications as pre-conditions for NRC staff approval of the EPU:

(1) Main transformer modifications will be performed (Commitment number 5).
(2) The main generator will be rewound and associated auxiliaries will be provided (Commitment number 6).

(3) High capacity main generator output circuit breakers and disconnect switches will be installed. Bus work will be completed (Commitment number 7).

Conclusion

The NRC staff has evaluated the effect of the power uprate on the necessary electrical system and environmental qualification of electrical components. Results of these evaluations show that implementation of the proposed modifications to the main generator, main transformers and the generator output breakers will be acceptable for the power uprate condition. The power uprate will have negligible impact on the grid stability, SBO, and the environmental qualification of electrical components. After the modifications, the design will meet the requirements of GDC 17, 10 CFR 50.63, and 10 CFR 50.49, and the proposed change will be, therefore, acceptable.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

Regulatory Evaluation

Instrumentation and control (I&C) systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (control elements), (3) to initiate the ESF systems and essential auxiliary supporting systems, and (4) to achieve and maintain a safe shutdown condition of the plant. Diverse I&C systems and equipment are provided for the express purpose of protecting against potential common-mode failures of I&C protection systems. The NRC staff conducts a review of the reactor trip system, the Engineered Safety Features Actuation System (ESFAS), safe shutdown systems, control systems, and diverse I&C systems for the proposed EPU to ensure that the systems and any changes required for the proposed EPU are adequately designed so that the systems continue to be able to perform their safety functions. The NRC staff's review is also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria for the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are given in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Nuclear power plants are licensed to operate at a specified core thermal power. The uncertainty values of this specified power level are calculated to avoid exceeding the power levels assumed in the design basis transient and accident analysis. The safety trip setpoints are also calculated to ensure that sufficient allowance exists between the trip setpoint and the safety limit (SL) to account for instrument uncertainties. The Commission's regulatory requirements related to this review can be found in 10 CFR 50.36(c)(1)(ii)(A), which requires that, where a limiting safety system setting (LSSS) is specified for a variable on which a SL has been placed, the setting be so chosen that automatic protective action will correct the most severe abnormal situation anticipated without exceeding a SL. LSSSs are settings for automatic protective devices related to variables having significant safety functions. Setpoints found to exceed TS limits are considered a malfunction of an automatic safety system. Such an occurrence could challenge the integrity of the reactor core, RCPB, containment, and associated systems. RG 1.105, Revision 3, "Setpoint for Safety-Related Instrumentation," is used to evaluate the conformance with 10 CFR 50.36.

Technical Evaluation

Suitability of Existing Instruments

The Waterford 3 plant protection system (PPS) is composed of two subsystems: the reactor protection system (RPS) and the ESFAS. The RPS is designed to trip the reactor by deenergizing the CEDM coils whenever any monitored condition reaches a trip setpoint. For each measured variable, the RPS uses a 2-out-of-4 channel logic arrangement, with each channel electrically and physically separated, to ensure no loss of functionality with a single failure. The RPS is designed to protect the reactor core and the reactor pressure boundary during AOOs, and to help mitigate the consequences of certain DBAs. The ESFAS is designed to initiate safety features whenever any monitored condition reaches a trip setpoint. The ESFAS also uses a 2-out-of-4 logic arrangement, with each channel electrically and physically separated to ensure no loss of functionality with a single failure. The ESFAS is designed to mitigate the consequences of certain DBAs, particularly by protecting the integrity of the containment building.

The RPS is discussed in Section 7.2 of the Waterford 3 UFSAR. The ESFAS is discussed in UFSAR Section 7.3. Systems required for safe shutdown are described in UFSAR Section 7.4. Instrumentation required to monitor, control, and provide interlocks for these systems is described in UFSAR Sections 7.5 and 7.6. The anticipated transients without scram (ATWS) mitigation system is described in UFSAR Section 7.8.

The EPU affects the process ranges of some of the instrumentation. The licensee has identified that the low SG pressure trip setpoint has decreased, and the maximum allowable linear power level - high trip setpoints are adjusted accordingly for EPU conditions. No other setpoints affecting the PPS will change due to EPU. The change of ranges on instrumentation supporting safe shutdown will not change the instrument functions as described in UFSAR Sections 7.4, 7.5, and 7.6. The instrument functions as described in UFSAR Sections 7.5A and 7.7 are not changed. The EPU does not change the design of the ATWS mitigation system as described in UFSAR Section 7.8. However, because the EPU lowers SG and main steam (MS) operating pressures, the diverse emergency FW (EFW) actuation signal (DEFAS) permissive setpoint will be lowered. This change ensures that the configuration for EFW system actuation is maintained under EPU conditions. Other actuation setpoints remain the same so that the ATWS mitigation system will not be actuated before initiation of the PPS.

The EPU configuration has been analyzed for a lower SG pressure. Changes to the PPS due to lower SG pressure will be implemented for the EPU. No setpoint changes to safe shutdown interlocks or alarms are required. The Core Protection Calculator (CPC) constants will be updated to be consistent with the new definition of 100 percent power and other requirements of the EPU and cycle-specific analysis. The licensee has stated that the methodology used to calculate the values for these constants is consistent with past practice and NRC-approved methods. The NRC has previously approved it and, therefore, finds this methodology acceptable. The EPU does not change the safety functions or design requirements such as separation, redundancy, or diversity of the I&C, as described in UFSAR Sections 7.2, 7.3, 7.4, 7.5, 7.6, 7.7, and 7.8. The I&C-related changes resulting from the EPU are consistent with the licensing basis and comply with acceptance criteria related to 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Therefore, the staff finds that the existing instruments at Waterford 3 are suitable for EPU operations.

Instrument Setpoint Methodology

The licensee has indicated that it has developed the proposed TS Allowable Values (AVs) in accordance with the methodology described in the Waterford 3 TS Bases, which is essentially equivalent to Method 3 of Instrument Society of America (ISA) Standard 67.04, Part 2, issued in 1994. Part 2 of ISA 67.04 has not been endorsed by the staff. The staff is currently in the process of evaluating a generic concern related to the use of Method 3 for calculating AVs. The licensee may be subject to further actions in the future when the generic concern is resolved.

Generic Concern Regarding Method 3

During recent reviews of proposed license amendments associated with changes to the TS LSSS, the staff has identified a concern regarding the method used by some licensees to determine the TS AVs. AVs are used in the TS to provide acceptance criteria for determination of instrument channel operability during periodic surveillance testing. The staff's concern relates to one of the three methods for determining the AV as described in ISA Recommended Practice ISA-RP67.04-1994, Part II, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."

Paragraph (c)(1)(ii)(A) of 10 CFR 50.36 states, in part that where a LSSS is specified for a variable on which an SL has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before the SL is exceeded. The Analytical Limit (AL) is the limit on the process variable at which the instrument loop protective action occurs, as assumed in the plant's safety analysis. Protective action at the AL ensures that the SL is not exceeded. The AL, however, does not account for uncertainties associated with the instrument loop. The instrument loop uncertainty is accounted for during calculation of an instrument loop's Trip Setpoint (TSP).

Method 3 in ISA-RP67.04-1994 calculates the TSP by subtracting the instrument loop uncertainty, also known as Total Loop Uncertainty (TLU), from the AL. The AV is then determined by adding the uncertainties measured during periodic surveillance testing (e.g., drift, calibration uncertainties, instrument accuracy) to the TSP. The relationship between these parameters is displayed graphically in Figure 1 of RG 1.105, Revision 3.

The staff concern is that an AV determined by Method 3 does not ensure adequate margin between the AV and the AL to account for uncertainties that are not addressed in periodic surveillance testing. Some examples of such omitted uncertainties are associated with instruments excluded from the tests, and uncertainties due to the effects of normal environmental variation. These additional uncertainties could result in sufficient error in the channel setpoint to cause the channel trip to occur only after the process variable has already exceeded the AL, even though the measured value of the setpoint is within the Method 3 AV. This could result in operation under conditions not addressed in the plant safety analyses, with attendant risk of violation of associated SLs. A determination that the measured as-found channel setpoint is within the Method 3 AV could give a false indication that the SLs were adequately protected. In such a case, no corrective action would be initiated and the potential violation of the associated SLs would go unnoticed. This concern was discussed in a meeting with NEI on October 8, 2003, as described in the NRC's meeting summary dated October 28, 2003 (ML033030193). NEI provided its position on this issue in a letter dated December 5, 2003 (ML033450410). The staff is currently working towards resolution of this generic concern.

Acceptability of the Proposed Changes

By Reference 26, the licensee submitted supplemental information that added 4 psi to the trip setpoint and AV that were previously submitted. Thus the revised trip setpoint is 666 psia and the revised AV is 652.4 psia. The SG pressure - low trip AL of 576 psia used in the EPU safety analysis remains the same. Thus, the methodology used to develop the revised SG pressure - low setpoint and AV value are based on a modification of ISA 67.04 Part 2 Method 3. The method utilized adds margin such that the difference between the AV and AL exceeds the non-measurable loop uncertainty. This in effect makes it equivalent to Method 1 of ISA 67.04 Part II; it is, therefore, acceptable to the staff.

The staff concludes that the method used to determine the TSP and AV for this instrument meets the requirements of 10 CFR 50.36. The proposed changes are, therefore, acceptable. The staff's conclusion does not signify that the generic concern discussed above is resolved for this plant. The licensee may be subject to further actions in the future when this generic concern is resolved for other instrument setpoints and allowable values.

Attachment 1 of Reference 1, Section 4.0 states that to improve clarity for the operators, the word "indicated" or the phrase "an indicated" is being added to identify those values in TSs that can be compared directly to plant instrument readings to ensure TS compliance.

The staff considers that the plant instrument readings from indicators can be used for channel check to detect a gross failure of an instrument channel. The indicator readings are only acceptable for the TS compliance, provided the indicator used (i.e., instrument loop) is shown to be reliable and conservative. There is no assurance that the "indicated" reading is reliable and conservative. The numbers specified in the TSs should be based on safety analysis and should meet the requirements of 10 CFR 50.36©)(2) to establish the lowest functional capability or performance level of equipment required for safe operation of the facility. Following two conference calls on March 10 and March 31, 2004, Entergy concurred with the NRC staff that the TS bases are an appropriate place to convey this type of information. By Reference 10, Entergy informed NRC of its decision to withdraw its request to add this terminology to various TSs and will instead retain the information in the technical bases. The staff finds this decision acceptable.

<u>Conclusion</u>

Based on the review of the Waterford 3 submittals, the staff finds that the Waterford 3 I&C systems will continue to perform their intended functions, as required by the plant license, which complies with the NRC's acceptance criteria for the quality of design of protection and control systems that are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. The staff concludes that the licensee's instrument trip setpoints for the proposed power uprate are consistent with the Waterford 3 licensing basis and, therefore, are acceptable. However, the licensee may be subject to further action in the future when the staff's generic concern with the instrument setpoint methodology used by the licensee is resolved.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

For proposed power uprates, the NRC staff reviews flood protection measures to ensure that SSCs important to safety are adequately protected from the consequences of internal flooding that result from postulated failures of tanks and vessels. Because the staff's review focuses on increases of fluid volumes in tanks and vessels that will occur as a result of a proposed power uprate and no changes are being made at Waterford 3 in any areas where safety-related equipment would be affected, an evaluation of this particular area by the staff is not required.

2.5.1.1.2 Equipment and Floor Drains

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper areas for processing or disposal while preventing a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment. Because the sources and quantities of liquids that enter the equipment and floor drains will remain unchanged for the proposed power uprate at Waterford 3 and postulated flood levels will not increase, an evaluation of the EFDS is not required.

2.5.1.1.3 Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the NRC staff's review of the CWS focuses on the impact that the proposed uprate will have on existing flooding analyses due to any increases that may be necessary in fluid volumes and installation of larger capacity CWS pumps or piping. Because the impact of the proposed power uprate on the licensee's flooding analysis is considered in Sections 2.5.1.1.1 and 2.5.1.3 of this evaluation, a separate evaluation for the CWS in this section is not required.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed conditions and high-pressure system ruptures. Potential missile sources include pressurized systems and components, and high-speed rotating machinery. The purpose of the staff's review is to confirm that: (1) safety-related SSCs are protected from internally generated missiles, and (2) failure of non-safety-related SSCs will not pose a challenge to safety-related SSCs. The staff's review focuses on system modifications, increases in system pressures, and component overspeed conditions that may be necessary following implementation of the proposed power uprate and are not bounded by existing analyses. The acceptance criteria that are most applicable to the staff's review of the protection of SSCs important to safety from the effects of internally generated missiles for proposed power uprates are based on GDC 4, and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Sections 3.5.1.1, and 3.5.1.2. Application of the review criteria and licensing-basis considerations are discussed in Section 3.5 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee evaluated the impact of the power uprate on internally generated missiles that may result from failures in high energy systems and overspeed of rotating components. Missiles generated from high energy systems in the turbine building are prevented from causing damage to safety-related equipment by the large separation that exists between high energy systems and the safety-related components. The licensee indicated that the few valves that are being replaced to support the proposed power uprate will be evaluated consistent with the existing licensing basis criteria and the same measures will be taken as those used for the existing valves to prevent missile generation and to protect safety-related equipment from damage. Finally, the licensee indicated that the operating pressures of systems that could generate missiles inside containment will not increase as a result of the proposed EPU and, therefore, missile protection considerations and measures that have been taken for protecting equipment inside containment will continue to be valid.

Overspeed protection is provided for the EFW pump turbine, EDGs, MFW pump turbines, and the main turbine by mechanical and electrical overspeed trip devices (overspeed protection of the main turbine is evaluated in Section 2.5.1.2.2). Missiles from the EFW pump turbine and the EDGs are not postulated since these components are designed to withstand 125 percent overspeed and because they are not normally operated. Neither the operating speed nor the overspeed protection circuits for the EFW pump turbine or the EDGs will be impacted by the proposed EPU and, therefore, the existing turbine missile considerations for these components will not be affected. Similarly, because the speeds of the MFW pump turbines and the main turbines will remain within their existing normal operating ranges and changes to the turbine overspeed trip setpoints are not required, turbine missile considerations for these components will also not be affected by the proposed power uprate.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on existing considerations and features that are credited for protecting safety-related equipment from the effects of internally generated missiles.

Summary

The NRC staff has reviewed the licensee's assessment of changes in system pressures, configurations, and equipment rotational speeds necessary to support the proposed EPU and finds that SSCs important to safety will continue to be protected from the effects of internally generated missiles following postulated accident conditions in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that protection of SSCs important to safety from the effects of internally generated missiles will continue to satisfy the requirements that are specified by GDC 4 and, consequently, the proposed EPU is acceptable with respect to internally generated missile considerations.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine-generator sets have the potential for producing large high-energy missiles. The NRC staff's review of the main turbines focuses on the effects of the proposed EPU on the turbine overspeed protection features to ensure that adequate turbine overspeed protection will be maintained. The acceptance criteria that are most applicable to the staff's review of the turbine generator for proposed power uprates are based on GDC-4, in that SSCs important to safety are required to be protected from the effects of turbine missiles by providing a turbine overspeed protection system, and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 10.2, "Turbine Generator." Application of the review criteria and licensing-basis considerations are discussed in Section 10.2 of the Waterford 3 UFSAR.

Technical Evaluation

The main turbine is provided with two diverse and redundant overspeed protection systems; one is electrical and the other is mechanical. The electrical overspeed protection system consists of two subsystems: 1) the overspeed protection controllers, which control turbine speed in the event of a partial or complete loss of load or if the turbine reaches or exceeds 103 percent of rated speed, and 2) the overspeed protection system, which closes all turbine valves when turbine speed reaches 111.5 percent of rated speed. The mechanical overspeed protection system closes all turbine valves when the turbine reaches 111 percent of rated speed by actuating the mechanical overspeed and manual trip devices. The turbine overspeed protection system is completely independent of normal turbine governing and other mechanical overspeed protective devices. In the event of a turbine trip, the main turbine overspeed protection systems ensure that the turbine generator unit will not exceed the design overspeed, which is 120 percent of rated speed.

The licensee provided information on planned modifications and acceptance testing of the main turbine in Attachment 1 Reference 2. Modifications will be made to the high pressure turbine steam path and will include installation of a new high pressure turbine rotor with all reaction blading, a new inner cylinder with stationary blading, a new inlet flow guide, and steam sealing components. The impact of EPU on the main turbine overspeed transient is discussed in Reference 27. The licensee, based on its evaluation of the new turbine-generator configuration, concluded that maximum rotor speed following a turbine trip will remain less than 120 percent of rated speed. The licensee provided additional information in Reference 29, to address turbine overshoot considerations following EPU implementation. The licensee's analysis, which is supported by Siemens/Westinghouse (SWPC) Engineering Study GO NOE21614, Rev. 2, considered the additional steam volume in the extraction steam piping and the water in the respective heaters, and included the failure of a single extraction steam reverse current valve. Based on the results of this analysis, the licensee concluded that the maximum rotor speed will not exceed 120 percent of rated speed following a turbine trip.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on turbine overspeed protection, including turbine overshoot considerations, thereby assuring that the main turbine will not exceed 120 percent of rated speed following postulated turbine trip events.

Summary

The NRC staff has reviewed the licensee's assessment of changes being made to the high pressure turbine, steam mass flow rate, and other operational characteristics necessary to support the proposed EPU and finds that existing design features will continue to protect the main turbine from overspeed conditions following postulated transient and accident conditions in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that main turbine overspeed protection will continue to satisfy the requirements that are specified by GDC 4 and, consequently, the proposed EPU is considered to be acceptable with respect to main turbine overspeed protection considerations.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff's review concerns the failure of high and moderate energy fluid system piping located outside containment. The purpose of the staff's review is to ensure that: (1) pipe failures will not cause the loss of needed functions of safety-related systems, and (2) pipe failures will not prevent placing the plant in a safe shutdown condition. The staff's review focuses on those system modifications and increases in system pressures and temperatures that are necessary in order to implement the proposed power uprate to confirm that the limitations and assumptions of previous pipe failure analyses remain valid or are otherwise addressed. The acceptance criteria that are most applicable to the staff's review of the postulated pipe failures for proposed power uprates are based on GDC 4, in that SSCs important to safety must be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids; and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 3.6.1, "Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment," and Branch Technical Position APCSB 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment." Application of the review criteria and licensing-basis considerations are discussed in Section 3.6 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee has evaluated the effects of the proposed power uprate on the existing high and moderate energy pipe failure analyses for systems located outside containment. High energy systems are those that exceed 200 EF or 275 psig, and moderate energy systems are those that do not exceed either of these limitations for more than 2 percent of the time when the system is operating. High energy pipe failure considerations include pipe whip, jet impingement, environmental impacts, subcompartment pressurization, and consequential flooding. High energy lines outside containment include MS, FW, SG blowdown, and CVC systems. Moderate energy pipe failure considerations include environmental impacts and consequential flooding effects.

The licensee reviewed the post-EPU operating conditions (pressure and temperature) of the high and moderate energy systems outside containment and determined that they are bounded by the conditions that were assumed in the existing pipe failure analyses. Consequently, no new pipe failure locations are required to be postulated and assessed for SSC impact (the dynamic effects associated with pipe failures is reviewed in Section 2.2.1). Also, because the flow conditions that were assumed in the current high energy pipe failure analyses associated with the SG blowdown and the CVCS will continue to be bounding for these systems following the proposed power uprate, the existing pipe failure analyses for these systems are not affected by the proposed EPU and no further analyses of pipe failures for these systems is necessary.

Because flow rates for post-EPU operation will be higher than previously assumed in the MS and FW systems, the licensee evaluated the impact of proposed EPU conditions on pressurization of subcompartments in the auxiliary building and jet impingement from breaks in the MS and FW lines. The MS and FW lines are routed outside the reactor building on top of the auxiliary building roof and, therefore, essential SSCs will not be affected by compartment pressurization effects or by jet impingement. Also for this reason, postulated failures associated with the MS and FW lines that occur following implementation of the proposed power uprate will not affect the environmental conditions that have been established for safety-related systems. Similarly, because the temperatures and pressures of moderate energy systems outside containment are not appreciably affected by the proposed power uprate, the licensee found that the environmental conditions that are currently assumed for safety-related equipment will not be affected by postulated moderate energy pipe failures following implementation of the proposed power uprate. Finally, the licensee found that the main control room (CR) will continue to be adequately protected from pipe whip by whip restraints at the postulated MS and FW break locations, and jet impingement will not impact the CR habitability requirements because breaks in the MS and FW pipes are too far removed to impinge on the main CR.

Flooding outside the containment caused by cracks in moderate energy lines, breaks in high energy lines, and activation of fire protection sprinklers was evaluated by the licensee. The flooding due to moderate energy line cracks and high energy line breaks was calculated assuming that the lines were being fed by an inexhaustible water supply and that the floor drains were 100 percent clogged. The flooding caused by activation of the fire protection sprinkler system assumed that half of the sprinkler heads in each room are activated. The licensee found that, since the normal operating temperatures and pressures for the moderate and high energy lines are not changing significantly as a result of the proposed EPU, there is a negligible impact to the flow rate through cracks and breaks in the moderate and high energy lines. Additionally, the proposed EPU has no impact on the classification of pipes that are considered to be moderate and high energy, or on the number of fire protection sprinkler heads in each room. Since the proposed EPU does not significantly impact the assumed flow rate of water through breaks and cracks in high and moderate energy pipes outside containment, or on the number of activated sprinkler heads that are assumed for flooding analysis purposes, the staff finds that flooding outside containment is not impacted by the EPU.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the consequences of postulated high and moderate energy pipe failures, and that pipe failures will not cause the loss of needed functions of safety-related systems or prevent placing the plant in a safe shutdown condition.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the consequences of postulated high and moderate energy pipe failures and finds that such failures will not cause the loss of needed functions of safety-related systems or prevent placing the plant in a safe shutdown condition in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that protection of essential SSCs from the effects of high and moderate energy pipe failures will continue to satisfy the requirements of GDC 4 following implementation of the proposed EPU and, consequently, the proposed EPU is considered to be acceptable with respect to high and moderate energy pipe failure considerations.

2.5.1.4 Fire Protection

Regulatory Evaluation

10 CFR 50.48(a) requires each operating nuclear power plant to have a fire protection plan that satisfies GDC 3. 10 CFR Part 50.48(b) required nuclear power plants licensed to operate prior to January 1, 1979 to implement Section III.G of Appendix R to 10 CFR Part 50. Waterford 3 was licensed to operate on March 16, 1985.

Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to 10 CFR Part 50, establishes fire protection features required to satisfy GDC 3 with respect to certain generic issues for nuclear power plants licensed to operate prior to January 1, 1979. For plants licensed after January 1, 1979 the applicable requirements of 10 CFR 50 Appendix R were incorporated into the NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 9.5-1. The approval and requirements for implementing the fire protection program were incorporated into an operating licensee condition.

Technical Evaluation

Based on Reference 1, the operation of Waterford 3 at the proposed power uprate will not affect the design or operation of the plant's fire detection systems, fire suppression systems, or fire barrier assemblies installed to satisfy NRC fire protection requirements, or result in an increase in the potential for a radiological release resulting from a fire. All changes to the plant configuration or combustible loading as a result of modifications necessary to implement the power uprate have been evaluated by the licensee under the plant's existing NRC-approved fire protection program.

The licensee indicated that compliance with the fire protection and safe-shutdown program will not be affected because the power uprate evaluation did not identify changes to design or operating conditions that will adversely impact the post-fire safe-shutdown capability. Further, power uprate does not change the credited equipment necessary for post-fire safe-shutdown, nor does it reroute essential cables or relocate essential components/equipment credited for post-fire safe shutdown. The licensee has made no changes to the plant configuration or combustible loading as a result of modifications necessary to implement the power uprate that affect the fire protection program.

Summary

Based on its review of the information provided in Reference 1, the staff concludes that the operation of Waterford 3 at the EPU RTP will not adversely affect the ability of the plant to achieve and maintain safe-shutdown conditions following a postulated fire event and is, therefore, acceptable.

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety valves. The tank is designed with a capacity to absorb discharged fluid from the PRVs during a specified step-load decrease. The PRT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The purpose of the staff's review is to confirm that operation of the PRT will continue to be consistent with the transient analysis of the RCS following implementation of the proposed power uprate, and that failure or malfunction of the PRT will not adversely affect safety-related SSCs. The staff's review focuses on any modifications to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the SVs; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of high energy line breaks and moderate energy line cracks in the pressurizer relief system. The acceptance criteria that are most applicable to the staff's review of the PRT for proposed power uprates are based on GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions and be protected against dynamic effects, including the effects of missiles; and other licensing basis considerations that are applicable. Specific review criteria are contained in SRP Section 5.4.11, "Pressurizer Relief Tank," and application of the review criteria and licensing-basis considerations are discussed in Section 5.4.11 of the Waterford 3 UFSAR.

Technical Evaluation

The PRT is sized to receive and condense steam from the pressurizer based on a loss of load, which is considered to be the maximum expected step load event, followed by a rod withdrawal incident as the plant returns to power. Overpressure protection for the tank is provided by a rupture disc that vents to the containment atmosphere, with a relief capacity greater than the combined relief capacity of the pressurizer safety valves.

The licensee analyzed anticipated operational occurrences to confirm that the size of the PRT is adequate to receive discharges without challenging the rupture disc. In Reference 23, the licensee provided the steam release to the PRT for the loss of load and rod withdrawal events. The steam release for the loss of load event was calculated to be less than 1000 lbm, and the transient analysis for the subsequent rod withdrawal event showed no release, since the SV setpoint is not reached. The Waterford 3 UFSAR gives the design capability of the PRT as being capable of condensing 791 lbm of steam from a loss of load event followed by a release of 441 lbm caused by a rod withdrawal as the plant returns to power. Since the calculated steam release (1000 lbm) for plant operation at EPU conditions is less than the current UFSAR assumed design capability (1232 lbm) of the PRT, the licensee concluded that it will continue to be able to perform its function following the proposed power uprate without any modifications. The licensee reviewed the PRT relative to the increase in pressurizer discharge that will occur as a result of the proposed EPU and concluded that the PRT will operate in a manner consistent with the transient analysis for the RCS and that safety-related SSCs will continue to be protected against postulated failures of the PRT.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the PRT to condense and contain steam that is discharged from the pressurizer safety valves and to protect safety-related SSCs from postulated PRT failures.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the PRT to perform its safety function and finds that the PRT will remain capable of condensing and containing steam that is discharged from the pressurizer safety valves, and safety-related SSCs will continue to be protected from PRT failures following postulated transient and accident conditions in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that the PRT will continue to satisfy the requirements that are specified in GDC 4 and, consequently, the proposed EPU is considered to be acceptable with respect to the PRT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

Regulatory Evaluation

The purpose of the NRC staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in the analyses that were previously completed. The acceptance criteria that are most applicable to the staff's review of fission product control systems and structures for proposed power uprates are based on GDC 41, insofar as it requires that a containment atmosphere cleanup system be provided to reduce the concentration of fission products released to the environment following postulated accidents such that the requirements of GDC 19, and the dose guidelines of 10 CFR 100 are satisfied; and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 6.5.3, "Fission Product Control Systems and Structures," and application of the review criteria and licensing-basis considerations are discussed in Section 6.5.3 of the Waterford 3 UFSAR.

Technical Evaluation

Fission product control systems control the release of fission products by operating in conjunction with fission product removal systems following a design-basis accident. The fission product control structures include the primary containment and the shield building. The containment atmosphere release system (CARS) is used in the primary containment to control fission products by purging the containment at low containment atmospheric pressure, and the CS system (CSS) is used to reduce iodine concentrations during an accident. In order to control fission products in the secondary containment following a design-basis accident, a negative pressure is maintained inside the shield building annulus by the shield building ventilation system (SBVS). During normal operation, the containment atmosphere purge system (CAPS) is used to reduce the level of radioactivity in the containment to allow personnel access. The CAPS is not used following a design basis accident and is not included within the scope of this evaluation.

Fission product removal systems that operate in conjunction with the fission product control systems following a design basis accident include the engineered safety features cleanup system and various other filtration and ventilation systems. Evaluation of these systems is discussed in Section 2.7.

The licensee has evaluated the impact of the proposed EPU on the capability of the CARS, CSS, and SBVS to perform their safety functions and has determined that operation of the fission product control systems will continue to be consistent with the modeling assumptions that were used in the DBA radiological dose calculations. The current SBVS analysis was performed for a power level of 3865 MWt, which bounds the proposed EPU power level; and the licensee concluded that the operational parameters for the SBVS are not impacted by the proposed power uprate and the exhaust air flow rate is sufficient for maintaining the requisite negative pressure conditions inside the shield building annulus. Also, because the calculated post-accident containment pressure following power uprate will remain within the specified design requirements for the containment structures, they are not impacted. Operation at the uprated power level will increase the LOCA source term and, therefore, the concentration of radioactivity in the containment post LOCA will also increase. However, the licensee has evaluated the offsite and CR doses and has determined that they will not exceed regulatory requirements. Evaluation of the radiological consequences is discussed in Section 2.9 of this SE and Reference 73.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of fission product control systems and structures to perform their functions.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of fission product control systems and structures to perform their functions and finds that the CARS, CSS, SBVS, and containment structures will continue to adequately control fission product releases to the environment such that the dose guidelines specified in 10 CFR 100 will not be exceeded and the requirements specified by GDC 19 will be satisfied following postulated accidents that occur during operation at the proposed power uprate conditions. Therefore, the NRC staff concludes that the fission product control systems and structures will continue to satisfy the requirements that are specified in GDC 41 following implementation of the proposed EPU and, consequently, the proposed EPU is considered to be acceptable with respect to fission product control systems and structures.

2.5.3.2 Main Condenser Evacuation System

The main condenser evacuation system (MCES) is not impacted by the proposed power uprate because the condenser air removal requirements during startup are not affected. The MCES is sized based on the volume of the condenser and desired evacuation time, neither of which is impacted by the proposed power uprate. Consequently, the existing capability to monitor the MCES effluent is also not affected by the proposed EPU and, therefore, NRC review of the MCES is not required.

2.5.3.3 Turbine Gland Sealing System

The turbine gland sealing system (TGSS) is designed to provide sealing steam for the turbine generator shaft and the main FW pump turbine shafts to prevent leakage of air into the turbine casing and the escape of steam into the turbine building, thereby preventing the uncontrolled release of radioactive material from steam in the turbine to the environment. Because no modifications are being made to the TGSS and non-condensable gases will continue to be monitored for radiation, the function of the TGSS will not be impacted by the proposed power uprate and an evaluation of the TGSS is not required.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup (SFPCC) system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for proposed power uprates focuses on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The acceptance criteria that are most applicable to the staff's review of the SFPCC system for proposed power uprates are based on GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; GDC 61, insofar as it requires that fuel storage systems be designed with residual heat removal capability that is commensurate with the safety function being performed, with provisions to prevent a significant loss of SFP coolant inventory under accident conditions; and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System," as supplemented by the guidance provided in Section 2.1 of Reference 31, Attachment 3, "Supplemental Spent Fuel Pool Cooling Review Criteria." Application of the review criteria and licensing-basis considerations are discussed in Section 9.1.3.1 of the Waterford 3 UFSAR.

Technical Evaluation

The SFPCC system is designed to maintain water quality and clarity, and remove decay heat generated by spent fuel assemblies in the pool. The SFP cooling portion of the SFPCC system is a seismic Category 1 closed loop system consisting of two half-capacity pumps and one full-capacity heat exchanger. Heat is removed from the SFP heat exchanger by the component cooling water system.

The SFP, analyzed for a bounding capacity of 2,485 fuel assemblies, can accommodate a full core of 217 along with 2,268 previously discharged fuel assemblies from 22 previous refueling batches or partial core of 116 fuel assemblies along with 2,369 previously discharged fuel assemblies from 23 previous refueling batches. The specific SFPCC system functions that are likely to be impacted by the proposed power uprate include:

(4) Removal of the decay heat produced from a full core that is placed in the SFP after reactor shutdown, in addition to the decay heat from 2,268 previously discharged fuel assemblies (approximately 22 previous refueling batches), which amounts to 2,485 fuel assemblies total. With two SFP cooling pumps operating, the maximum SFP temperature is not allowed to exceed 155 EF.

(5) Removal of the decay heat produced by offloading approximately 53 percent of the core (116 fuel assemblies) into the SFP after reactor shutdown, in addition to the decay heat that is produced from 2,369 previously discharged fuel assemblies (approximately 23 previous refueling batches), which amounts to 2,485 fuel assemblies total. With one SFP pump operating and assuming the worst-case single active failure coincident with a loss of offsite power, the maximum SFP water temperature is not allowed to exceed 140 EF.

The licensee has evaluated the SFPCC system performance for the proposed EPU conditions and has determined that the temperature limitations for both the normal core offload and full core offload will not be exceeded following the proposed power uprate. In order to ensure that the design-basis SFP temperature limitations will not be exceeded, the licensee plans to administratively control the decay time that is required following reactor shutdown before the fuel can be transferred to the SFP. The current time limitations for the partial core offload case are conservatively based on a maximum allowable heat load in the SFP of 22.1 MBtu/hr, while the current heat removal capacity of the SFPCC system for the partial core offload case (assuming the worst-case single active failure) is calculated by the licensee to be 29.0 MBtu/hr. The licensee has developed new offload limits based on the decay heat associated with plant operation at the proposed power uprate conditions crediting the 29.0 MBtu/hr allowable heat load. The staff reviewed the methodology the licensee used to determine the core offload limits and concluded that the decay heat load calculations were performed in accordance with the provisions of BTP 9-2, “Residual Decay Energy for Light Water Reactors for Long-Term Cooling.”

In the case of the full core offload, the licensee is also proposing to maintain the SFP below the applicable design basis temperature of 155 EF by administratively controlling the decay time that is required following reactor shutdown before the fuel can be transferred to the SFP. Currently the offload limits for the full core offload are based on the component cooling water temperature. For post-EPU operation, the full core offload limits will be based on a maximum allowable heat load of 50.4 MBtu/hr. This heat load is the same as the maximum heat load for the full core offload analysis used in the current licensing basis. The licensee provided offload limits and corresponding heat loads for the full core offload refueling case in Attachment 2 to Reference 28. The actual maximum heat load calculated by the licensee for the full core offload is approximately 49 MBtu/hr. Since the maximum heat load considered for the full core offload case in the current analysis continues to bound that for the uprated plant, the pool temperature limit of 155 EF for the full core offload case will not be exceeded. In addition, EPU will not result in a change in the time to boil since the time to boil is dependent on the maximum heat load and peak SFP temperature, both of which are bounded by the current licensing basis analysis.

In response to questions that were raised by the NRC staff concerning the SFP heat load analysis, the licensee provided additional information in Reference 5. The staff reviewed the information that was submitted and found that while the licensee's evaluation accounted for changes in decay heat due to plant operation at the proposed power uprate conditions, it seemed to incorporate several other changes in methods, assumptions, and inputs that appeared to be inconsistent with the existing Waterford 3 licensing basis. The staff requested that the licensee specifically identify and address any changes that were being proposed to the SFPCC system licensing basis that required NRC review and approval.

In Reference 23, the licensee provided additional information concerning the changes that were being made to the SFPCC licensing basis. During a public meeting held at NRC headquarters on November 10, 2004, the licensee indicated that its intention was to implement any changes to the SFPCC system licensing basis via the 10 CFR 50.59 process and that NRC review and approval would not be required. Therefore, the staff's review of the impact of the proposed power uprate on the SFPCC system does not include approval of any changes to the SFPCC licensing basis.

Based on a review of the information that was provided by the licensee related to the SFPCC system and the proposed use of administrative controls to manage the heat load in the spent fuel pool during refueling, the staff concludes that operation of the plant at the proposed EPU power level will not exceed the existing design-basis capability of the SFPCC system.

Summary

The NRC staff has reviewed the licensee's assessment related to the SFPCC system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel pool cooling function of the system. Based on this review, the NRC staff finds that the SFPCC system will continue to provide sufficient cooling capability to cool the spent fuel pool following implementation of the proposed EPU and will continue to meet the requirements of GDC 44 and GDC 61. Therefore, the NRC staff finds the proposed EPU to be acceptable with respect to the SFPCC system.

2.5.4.2 Station Service Water System

Waterford 3 does not have a station service water system. Instead, Waterford 3 has two safety-related cooling water systems designated as the component cooling water system and the auxiliary component cooling water system. The functions normally performed by the station service water system are performed by these systems at Waterford 3. The staff's evaluation of these systems is addressed in Section 2.5.4.3, "Reactor Auxiliary Cooling Water Systems," of this safety evaluation.

2.5.4.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The reactor auxiliary cooling water systems at Waterford 3 include the component cooling water system (CCWS) and the auxiliary component cooling water system (ACCWS). Both are closed-loop cooling water systems that provide cooling for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review focuses on the capability of these auxiliary cooling water systems to accommodate any increase in heat load that is necessary for implementing the proposed power uprate. The acceptance criteria that are most applicable to the staff's review of the reactor auxiliary cooling water systems for proposed power uprates are based on GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems," as supplemented by GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions." Application of the review criteria and licensing-basis considerations is discussed in Section 9.2.2 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee evaluated the impact of the proposed EPU on the capability of the CCWS and ACCWS to perform their safety functions. The CCWS and ACCWS functions that are likely to be impacted by the proposed power uprate include providing sufficient cooling water for achieving safe shutdown conditions, providing sufficient cooling water to support refueling operations, and mitigating accident conditions coincident with a LOOP, assuming a single active failure.

According to the licensee, the maximum heat loads on the CCWS and ACCWS occur during the design-basis LOCA. The licensee determined that under the proposed EPU conditions, the maximum calculated heat load from containment will actually be lower than what is currently assumed due to use of revised analytical methods. The licensee indicated that the revised methods were previously reviewed and approved by the NRC via License Amendment 165, dated July 6, 2000. The ultimate heat sink (UHS) analysis was not updated to incorporate the revised heat loads when Amendment 165 was issued since the containment heat loads used in the UHS analysis remained conservative relative to the revised heat loads and updating the UHS analysis was not required to support plant operation. The UHS analysis is now being updated in support of the proposed EPU and incorporates the heat loads associated with the proposed power uprate conditions. The licensee concluded that since the containment heat load analysis is unaffected by the proposed power uprate, resolution of the GL 96-06 issues will also not be affected because the resolution of GL 96-06 issues depends directly on containment temperature considerations. Finally, the licensee indicated that any changes that need to be made to the existing heat exchanger performance monitoring criteria that were established in order to resolve the concerns expressed in GL 89-13 will be made in accordance with the Waterford 3 design change process as deemed necessary to support the proposed power uprate conditions.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the auxiliary cooling water systems to perform their functions. Because the calculated heat loads for post-EPU operation are bounded by the current heat load analysis, the staff agrees that the capabilities of the CCWS and ACCWS will not be impacted by the proposed power uprate. Likewise, the licensee's resolution of the GL 96-06 conditions will also not be affected, and existing GL 89-13 programmatic controls will continue to assure that heat exchanger performance is maintained consistent with licensing-basis considerations following implementation of the proposed power uprate.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the CCWS and ACCWS to perform their functions and finds that these systems, including resolution of GL 89-13 and GL 96-06, will not be affected by the proposed power uprate. Therefore, the NRC staff concludes that the CCWS and ACCWS will continue to satisfy the requirements that are specified in GDC 44 and, consequently, the proposed EPU is acceptable with respect to the reactor auxiliary cooling water systems.

2.5.4.4 Ultimate Heat Sink

Regulatory Evaluation

The UHS provides the safety-related cooling medium required to dissipate the heat removed from the reactor and its auxiliaries during normal operation, refueling, and accident conditions. It consists of two forced-draft dry cooling towers (DCTs) and two mechanical-draft wet cooling towers (WCTs), with water stored in the basins of the WCTs. The WCTs remove heat from the component cooling water system (CCWS) via the ACCWS. The WCT basins must contain enough water to support at least 30 days of post-accident cooling. The NRC staff's review focuses on the impact that the proposed EPU will have on the decay heat removal capability of the UHS. This includes a review of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The acceptance criteria that are most applicable to the staff's review of the UHS for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-44, "Cooling Water," insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 9.2.5, "Ultimate Heat Sink," and application of the review criteria and licensing-basis considerations are discussed in Section 9.2.5 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee has evaluated the performance capability of the Waterford 3 UHS under the proposed EPU conditions and has determined that the assumed heat loads will remain bounded by the current pre-EPU analysis. As discussed in Section 2.5.4.3 of this SE, the licensee has determined that the maximum CCWS heat loads under the proposed EPU conditions will actually be less than what is currently assumed. However, the total mass and thermal energy release for the accident duration will be slightly larger for the proposed power uprate resulting in a slight increase in the long-term heat removal requirements. The licensee's analysis shows that the wet and dry cooling towers have sufficient capacity to accommodate the post-LOCA heat loads and that the UHS has sufficient water volume in one basin to meet the 30-day heat removal requirements for the essential loads without makeup from an external source of water consistent with the Waterford 3 licensing basis. The licensee has also reviewed the meteorological conditions that have been observed at Waterford 3 and has confirmed that the licensing-basis meteorological conditions that were assumed for determining the performance capability of the UHS during initial plant licensing continue to be bounding.

In order to satisfy post-LOCA decay heat removal requirements, the Waterford 3 TS requires the temperature of the water in the WCT basin to be less than or equal to 89 EF. During a public meeting with the licensee on November 10, 2004, measurement uncertainty was included as a topic of discussion and, with respect to UHS temperature, the licensee indicated that measurement uncertainty was not explicitly accounted for when confirming that the TS UHS temperature requirement is satisfied. The licensee believes that heat exchanger performance testing that is completed in accordance with its GL 89-13 program may adequately account for measurement uncertainty. It is the licensee's view that measurement uncertainty need not be explicitly accounted for when the applicable analyses are relatively insensitive to changes in the assumed value of the parameter in question. The licensee referred the staff to TS Bases Insert 3/4.0-1 in Attachment 3 of Reference 10, for a listing of other parameters that are monitored both with and without accounting for measurement uncertainty. In order to resolve an ongoing staff concern, the licensee agreed to an amendment condition (Reference 71) that requires the licensee to submit for NRC review and approval a description of how it accounts for instrument uncertainty for each TS parameter impacted by EPU, prior to exceeding 3441 MWt.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the UHS to perform its safety function. Because the calculated heat loads for post-EPU operation are bounded by the current heat load analysis and the water inventory in the WCT basin is sufficient to accommodate the slight increase in the long-term heat removal requirements, the staff agrees that the capabilities of the UHS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

<u>Summary</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the UHS to perform its safety function and finds that the UHS will remain capable of dissipating the reactor decay heat following postulated accident conditions in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that the UHS will continue to satisfy the requirements that are specified in GDC 44 and, consequently, the proposed EPU is acceptable with respect to the UHS.

2.5.4.5 Emergency Feedwater System

Regulatory Evaluation

In conjunction with a seismic Category I water source, the EFWS functions as an emergency system for the removal of heat from the primary system when the MFW system is not available. The EFWS may also be used to provide decay heat removal necessary for withstanding or coping with an SBO. The NRC staff's review focuses on the capability of the EFWS to provide sufficient EFW flow for the proposed power uprate to ensure adequate cooling with the increased decay heat load. The staff also reviews the effects of the proposed EPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The acceptance criteria that are most applicable to the staff's review of the EFWS for proposed power uprates are based on GDC 34, insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core; GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 10.4.9, "Auxiliary Feedwater System," and application of the review criteria and licensing-basis considerations are discussed in Section 10.4.9 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee evaluated the performance capability of the EFWS for plant operation at the proposed EPU conditions. Although the proposed EPU will cause an increase in decay heat, the licensee has determined that the existing capability of the EFWS is adequate to provide the necessary discharge pressure and flow rate consistent with accident analysis assumptions. Also, since no changes are required in system performance and no system modifications are required, the licensee concluded that the proposed EPU will not increase the likelihood of creating fluid flow instabilities or waterhammer due to operation at the proposed EPU conditions. Finally, the licensee has determined that the existing TS water inventory requirements for the CSP and the WCT basin will continue to satisfy the licensing-basis cooldown requirements.

The staff requested that the licensee provide additional information on how the increased heat load is accommodated by the EFWS without any change in system performance. In Reference 5, the licensee stated that, according to the UFSAR, the EFWS is credited for delivering at least 575 gpm to the steam generators at the first MSSV setpoint pressure during loss of FW events (no changes to the MSSV setpoints are being made in support of the proposed EPU). The licensee's analysis demonstrates that either the EFWS turbine-driven pump or both EFWS motor-driven pumps can deliver the requisite 575 gpm to the SGs. The performance capability of the EFWS is an input to the various loss of FW event analyses that are described in UFSAR Section 15.2 and, as discussed in Section 2.13.2 of the license amendment request and on Pages 17-19 of Reference 5, the licensee's post-EPU event analyses using these EFWS flow assumptions demonstrate acceptable results.

The licensee also evaluated the water inventory that will be needed to satisfy the licensing-basis decay heat removal requirements for the proposed power uprate conditions. With respect to the condensate storage pool, analysis of the most limiting scenario indicated that the minimum required inventory would increase from 142,000 gallons to 165,750 gallons, which is within the 170,000 gallons that is allotted for this purpose and required to be maintained in the condensate storage pool by the Waterford 3 TSs. See Section 3.0 for the staff's evaluation of proposed temperature requirements for CSP.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the EFWS to perform its safety function.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the EFWS to perform its safety function and finds that the EFWS will remain capable of supplying water to the SGs for dissipating the reactor decay heat following postulated accident conditions in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that the EFWS will continue to satisfy the requirements that are specified in GDC 34 and GDC 44. Consequently, the proposed EPU is acceptable with respect to the EFWS.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focuses primarily on the effects of the proposed EPU on the system's capability to isolate flow in the event of a break, satisfy decay heat removal requirements, and provide steam for safety applications. The capability of the MSSS to withstand the steam hammer loads that result from the rapid closure of the main steam isolation valves (MSIVs), design considerations associated with the rapid closure of the MSIVs, protection of the SGs from overpressure conditions, piping stresses due to LOCA loads and SG nozzle loads are contained in Section 2.2 of this SE. The acceptance criteria that are most applicable to the staff's review of the MSSS for proposed power uprates are based on GDC 34, insofar as it requires that a system be provided to transfer fission product decay heat and other residual heat from the reactor core; GDC 57, insofar as it requires isolation capability for closed systems that penetrate the containment boundary; and other licensing-basis considerations that may be applicable. Specific review criteria are contained in SRP Section 10.3, "Main Steam Supply System," and application of the review criteria and licensing-basis considerations are discussed in Section 10.3 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee has evaluated the effects of the proposed EPU on the capability of the MSSS to isolate steam flow, satisfy decay heat removal requirements, and supply steam to drive the turbine-driven EFW pump. The proposed EPU will result in a reduction in the normal operating temperature and pressure and an increase of approximately 8.6 percent in the steam mass flow rate. In order to achieve the higher steam flow rate, the licensee will replace the high pressure turbine steam path, including the high pressure turbine rotor with all-reaction blading, a new inner cylinder with stationary blading, a new inlet flow guide, and steam sealing components. The licensee has evaluated the MSSS piping and has concluded that it will continue to be acceptable for EPU operation in its current configuration. The steam lines with increased velocities that exceed design requirements were found to be infrequently operated or were recommended for inclusion into the Flow Accelerated Corrosion Program by the licensee. The staff's assessment of excessive flow velocities and the adequacy of the licensee's FAC Program to adequately compensate for this condition is contained in Section 2.1.8 of this SE.

The licensee indicated that the accident analyses for post-EPU operation use the same closure time for the MSIVs that is assumed in the current analyses and, consequently, the MSIV closure time requirements are not affected by the proposed power uprate. Likewise, no significant changes to the EFW pump flow rates or operating conditions were identified, nor were any of the operating conditions for the turbine-driven EFW pump turbine found to be significantly affected by EPU.

The ADVs are relied upon for decay heat removal during a LOOP, and post-EPU operation proposes to also credit the ADVs for SG pressure control and decay heat removal in the small break LOCA event. For the LOOP event, the ADVs are assumed to pass the same flow rate during post-EPU operation as currently assumed. For the small break LOCA case, the ADVs are credited to pass a fraction of the valve design capacity. Therefore, the sizing of the valves is adequate for EPU conditions. Assessment of the acceptability of crediting the ADVs for providing SG overpressure protection is contained in Section 2.2 of this SE.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the MSSS to perform its safety functions.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSSS and finds that the MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, and supply steam to the turbine-driven EFW pump in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that the MSSS will continue to satisfy the requirements that are specified in GDC 34 and GDC 57. Consequently, the proposed EPU is acceptable with respect to the MSSS.

2.5.5.2 Main Condenser

Regulatory Evaluation

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the steam bypass system (SBS). The NRC staff's review focuses on the impact of the proposed EPU on the capability of the main condenser to withstand the blowdown effects of steam from the SBS. The impact of the proposed power uprate on the main condenser flooding analysis is included within the scope of Section 2.5.1.1.1, and is not evaluated in this section. The acceptance criteria that are most applicable to the staff's review of the main condensers for proposed power uprates are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and other licensing-basis considerations that are applicable. Specific review criteria are contained in SRP Section 10.4.1, "Main Condensers," and application of the review criteria and licensing-basis considerations are discussed in Section 10.4.1 of the Waterford 3 UFSAR.

Technical Evaluation

The main condenser provides a continuous heat sink for the exhaust from the three tandem-compound low pressure turbines; miscellaneous flows, drains, and vents during normal plant operation; and for the SBS in the initial phase of reactor cooldown after plant shutdown. The proposed power uprate will increase the total mass flow of steam to the main condenser and the licensee has determined that as a consequence, main condenser tube vibration may be excessive. The licensee indicates on page 8 of Attachment 1 of Reference 28 that additional staking of the main condenser tube supports will be installed to minimize potential effects of flow-induced vibration.

Based on a review of the information that was submitted and the licensee's plans to complete the necessary modifications to prevent condenser tube vibration prior to EPU operation, the staff finds the proposed EPU acceptable with respect to the main condenser.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the main condenser and finds that the planned actions to stake the tube supports provide adequate assurance that the main condenser will continue to maintain its ability to withstand the blowdown effects of steam from the SBS. Therefore, the NRC staff concludes that the main condenser will continue to satisfy the requirements that are specified in GDC 60 and, consequently, the proposed EPU is acceptable with respect to the main condenser.

2.5.5.3 Steam Bypass

The steam bypass system (SBS) is designed to discharge a stated percentage of rated main steam flow directly to the main condenser, bypassing the turbine and enabling the plant to take step load reductions up to the capacity of the SBS without the reactor or turbine tripping. The system is also used during startup and shutdown to control SG pressure. The NRC staff's review focuses on the impact that the proposed power uprate will have on the SBS with respect to adverse effects that postulated system piping failures could have on essential equipment. See Section 2.5.1.3 for the staff's evaluation related to postulated system piping failures. Transient analysis considerations, including SBS capacity and the consequences of inadvertent SBS operation are contained in Section 2.8 of this SE.

2.5.5.4 Condensate and Feedwater

Regulatory Evaluation

The CFWS provides feedwater at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFWS that is classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valves. The NRC staff's review focuses on the effects of the proposed EPU on the capability of the CFWS to provide feedwater to the SGs and to isolate and preserve the safety-related portions of the CFWS consistent with accident analysis assumptions; and to prevent unacceptable fluid flow instabilities (e.g., water hammer) during normal plant operation, transient, and accident conditions. The consequences of pipe breaks are evaluated in Section 2.5.1.3, and are not considered in this section of the evaluation. The acceptance criteria that are most applicable to the staff's review of the CFWS for proposed power uprates are based on GDC 34, insofar as it requires that a system be provided to transfer fission product decay heat and other residual heat from the reactor core; GDC 44, insofar as it requires the capability to transfer heat from safety-related SSCs to a heat sink under normal operating and accident conditions be provided with suitable isolation to assure that the system safety function can be accomplished assuming a single failure; GDC 57, insofar as it requires isolation capability for closed systems that penetrate the containment boundary; and other applicable licensing-basis considerations. Specific review criteria are contained in SRP Section 10.4.7, "Condensate and Feedwater System," and application of the review criteria and licensing-basis considerations are discussed in Section 10.4.7 of the Waterford 3 UFSAR.

Technical Evaluation

The licensee has performed a comprehensive evaluation of the capability of the CFWS to supply feedwater to the SGs for the proposed power uprate conditions, including operation at 102 percent of the proposed EPU power level, and has determined that the existing CFWS is capable of performing this function without modification. The licensee also indicated that the main and startup feedwater regulating valves are adequately sized to pass the higher flow rate required for post-EPU operation as well as for performing their backup feedwater isolation function; and the feedwater isolation valves are adequately sized to perform the requisite feedwater isolation function. The licensee stated that the system flow rates considered in the FW waterhammer analysis bound the FW system flow rates under EPU conditions. Thus the staff concludes that the fluid flow instabilities will not occur as a result of the proposed power uprate. As for CFWS design limitations, the licensee found that the drain valves for the moisture separator reheater (MSR) drain tank and for feedwater heater #6, and the feedwater heater level control valves may be undersized for post-EPU operation and may have to be modified or replaced in order to satisfy flow requirements; and elevated fluid velocities in some of the CFWS and extraction steam piping segments will increase the wear rates by a low to moderate amount. The evaluation of elevated fluid velocities and accelerated wear rates are contained in Section 2.1 of this SE.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the CFWS to perform its safety functions.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFWS and finds that the CFWS will maintain its ability to provide feedwater to the SGs, isolate and preserve the safety-related portion of the CFWS, and prevent unacceptable fluid flow instabilities in accordance with licensing-basis assumptions. Therefore, the NRC staff concludes that the CFWS will continue to satisfy the requirements that are specified in GDC 34, GDC 44, and GDC 57. Consequently, the proposed EPU is acceptable with respect to the CFWS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMS) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of effluents from the condenser air removal system, the SG blowdown flash tank, the containment purge exhaust, and building ventilation system exhausts. The NRC staff's review of the GWMS focuses on the effects that the proposed EPU may have on methods of treatment; expected releases; principal parameters used in calculating releases of radioactive materials in gaseous effluents; and the accumulation and management of explosive mixtures. The acceptance criteria for the GWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 61, insofar as it requires that systems that contain radioactivity be designed with suitable shielding and filtration; (4) 10 CFR 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. Specific review criteria are contained in SRP Section 11.3, "Gaseous Waste Management Systems," and application of the review criteria and licensing-basis considerations are discussed in Section 11.3 of the Waterford 3 UFSAR.

Technical Evaluation

The GWMS is designed to collect, process, and dispose of radioactive gaseous waste in accordance with the requirements outlined in 10 CFR Part 20 and in 10 CFR Part 50, Appendix I, and is discussed in the Waterford 3 Final Environmental Statement (FES). The EPU will not result in changes in the design or operation of the GWMS and, therefore, the flow rates of the waste gas compressors and the volume of processed gas that is delivered to the GWMS will remain the same as for pre-EPU plant operation and the existing capacity of the GWMS will continue to be adequate.

Radiological and environmental monitoring of the waste streams is not affected by the proposed EPU and no new or different radiological release paths will be introduced. However, the proposed EPU will result in an increase in the activity associated with gaseous radwaste and, therefore, radiological releases and offsite doses will be impacted. The licensee estimated offsite doses for post-EPU operation using the PWRGALE code to estimate the increase in gaseous releases and the GASPAR code to estimate the resultant offsite doses. The offsite doses due to gaseous releases were estimated to increase by no more than 15 percent as a result of the proposed power uprate. The resulting dose, which the licensee lists as the "projected uprate average dose, " will remain well below those reported in the FES, and what is allowed by 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

The GWMS is designed to prevent or preclude explosive mixtures. A gas analyzer package monitors hydrogen and oxygen concentrations in areas where potentially explosive mixtures could develop. When hydrogen or oxygen concentrations exceed a predetermined set point, an alarm is annunciated. The proposed power uprate does not make any changes to the design or operation of the gas analyzer package and, therefore, the capability to prevent or preclude explosive mixtures in the GWMS will not be affected.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in offsite dose will be relatively small and remain well below that reported in the Waterford 3 FES, and current offsite dose complies with 10 CFR 20.1302 and 10 CFR Part 50, Appendix I, requirements, the staff agrees that the capabilities of the GWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the GWMS to perform its functions and finds that the GWMS will continue to control the release of radioactive materials and preclude the possibility of waste gas explosions in accordance with the plant licensing basis. Therefore, the NRC staff concludes that the GWMS will continue to satisfy the requirements specified in 10 CFR 20.1302; 10 CFR Part 50, Appendix A, GDC 60 and GDC 61; and 10 CFR Part 50, Appendix I. Consequently, the proposed EPU is acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

Regulatory Evaluation

The liquid waste management system (LWMS) consists of process equipment and instrumentation necessary to collect, process, monitor and recycle and/or dispose of liquid radioactive waste. Major components in the system include transfer pumps and various waste system tanks used for collecting, holdup, and processing of the waste streams. The NRC staff's review of LWMS focuses on the effects that the proposed EPU may have on previous analyses and considerations related to the processing and management of liquid radioactive waste; methods of treatment; expected releases; and principal parameters used in calculating the release of radioactive materials in liquid effluents. The acceptance criteria for the LWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC-61, insofar as it requires that systems that contain radioactivity be designed with suitable confinement, shielding, and filtration; (4) 10 CFR 50, Appendix I, Sections II.A and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. Specific review criteria are contained in SRP Section 11.2, "Liquid Waste Management Systems," and application of the review criteria and licensing-basis considerations are discussed in Section 11.2 of the Waterford 3 UFSAR.

Technical Evaluation

The LWMS is designed to collect, process, and dispose of radioactive liquid waste in accordance with the requirements outlined in 10 CFR Part 20 and in 10 CFR Part 50, Appendix I, and is discussed in the Waterford 3 Final Environmental Statement. The proposed power uprate will not change the operation or design of the equipment used in the LWMS, the radiological and environmental monitoring of the waste streams will not be affected, and no new or different radiological release paths will be introduced as a result of the proposed power uprate. Since the design and operation of the LWMS will not change, and the volume of fluid flowing into the liquid radwaste system will not increase significantly as a result of EPU, the capacity of the LWMS will continue to be adequate.

The licensee evaluated the impact of the proposed power uprate on the LWMS by conservatively (compared to GALE code analysis) assuming that the activity in the liquid waste system will increase linearly with power. The ratio of the power increase (3716/3390, or 9.6 percent) was applied to the Waterford 3 liquid release radiation dose averaged over the last three years. The resulting dose, which the licensee lists as the "projected uprate average dose," remained well below those reported in the FES, and what is allowed by 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in offsite dose will be relatively small and remain well below that reported in the Waterford 3 FES, and it complies with 10 CFR 20.1302 and 10 CFR Part 50, Appendix I, requirements, the staff agrees that the capabilities of the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the LWMS to perform its functions and finds that the LWMS will continue to control the release of radioactive materials in accordance with the plant licensing basis. Therefore, the NRC staff concludes that the LWMS will continue to satisfy the requirements specified in 10 CFR 20.1302; 10 CFR Part 50, Appendix A, GDC 60 and GDC 61; and 10 CFR Part 50, Appendix I. Consequently, the proposed EPU is acceptable with respect to the LWMS.

2.5.6.3 Solid Waste Management Systems

Solid radioactive waste consists of wet and dry waste. Wet waste consists mostly of low specific activity spent secondary and primary resins and filters, and oil and sludge from various contaminated systems. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because this is a subset of the evaluations performed in Sections 2.5.6.1 and 2.5.6.2, a separate evaluation of solid waste management systems is not required.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focuses on increases in emergency diesel generator (EDG) electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The staff's acceptance criteria for the EDG fuel oil storage and transfer system that are most applicable to the staff's review of proposed power uprates are based on GDC 17, insofar as it requires onsite power supplies to have sufficient capacity and capability to perform their safety functions, assuming a single failure, and other licensing-basis considerations that apply. Specific review criteria are contained in SRP Section 9.5.4, "Emergency Diesel Fuel Oil Storage and Transfer System," and application of the review criteria and licensing-basis considerations are discussed in Section 9.5.4 of the Waterford 3 UFSAR.

Technical Evaluation

There are two EDGs for Waterford 3. The EDG fuel oil storage and transfer (FOST) system provides a separate and independent fuel oil supply train for each EDG. The system consists of a feed (day) tank, a fuel oil storage tank, a fuel oil transfer pump, and associated piping, valves, instrumentation, and controls. The EDG licensing basis requires that each fuel oil storage tank have sufficient storage capacity for at least seven days operation of an EDG to meet the engineered safety feature load requirements following a design-basis accident with a concurrent loss of offsite power, assuming a single active or passive failure.

The licensee has evaluated the impact of the proposed power uprate on the capability of the EDG to perform its safety function. As stated in Reference 1, the licensee determined that, while the operating duration of certain safety system components will increase due to the higher decay heat load associated with post-EPU operation, the post-accident electrical loads will continue to be within the design rating of the EDGs. The licensee developed a time-dependent load profile based on the expected electrical demands and run time for each component powered by the EDG under accident conditions to assess the impact of the prolonged safety system operating times. Based on the EDG fuel oil consumption rates that were assumed, the licensee initially determined that the fuel oil inventory that is required to be maintained in the fuel oil storage tanks by the Waterford 3 TSs would be sufficient to support the electrical demands of their respective EDGs for seven days. However, based on the results of confirmatory EDG fuel oil consumption rate testing that was subsequently performed, the licensee concluded that the required fuel oil inventory was sufficient for only 6.75 days of post-accident EDG operation at EPU conditions. The licensee informed the staff of this result in August 2004.

In order to resolve this problem and move forward with the proposed power uprate, Reference 25 established certain commitments and proposed changes to the TS requirements for EDG fuel oil inventory. As discussed in Section 3.0 of this evaluation, the staff considers the proposed TS changes in conjunction with the commitments that were established to be acceptable for assuring that sufficient fuel oil inventory is maintained for the proposed EPU conditions consistent with the EDG licensing basis. Also, based on a review of the electrical demands that are placed on the EDGs following postulated accident conditions at the uprated conditions, the staff confirmed that the power requirements of the emergency electrical loads will not exceed the design rating of the EDGs.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the EDGs to perform their safety function. Because the emergency electrical loads will not exceed the design rating of the EDGs and proposed changes to TS requirements in conjunction with licensee commitments will assure sufficient fuel oil inventory for post-accident operation, the staff agrees that the EDGs will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the EDGs to perform their safety function and finds that the rating of the EDGs is sufficient for satisfying the post-accident electrical loads following the proposed power uprate, and the proposed TS changes in conjunction with commitments that were made will assure that the Waterford 3 EDGs will remain capable of performing their safety function during postulated accident conditions consistent with the plant licensing basis. Therefore, the NRC staff concludes that the EDGs will continue to satisfy the requirements specified in GDC 17 and consequently, the proposed EPU is acceptable with respect to the EDGs.

2.5.7.2 Light Load Handling System (Related to Refueling)

The light load handling system (LLHS) includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. Because the post-EPU fuel is of the same overall dimensions and weight as the pre-EPU fuel, this area of review is not affected by the proposed power uprate and, therefore, an evaluation of the LLHS is not required.

2.6 Containment Review Considerations

The Waterford 3 containment structure consists of a steel containment vessel enclosing the RCS. The steel containment vessel is, in turn, surrounded by a shield building.

2.6.1 Primary Containment Functional Design (Containment Isolation)

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The NRC staff's review covered the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary system line-breaks. The NRC's acceptance criteria for primary containment functional design are based on GDC 16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; GDC 50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; and GDC 57, insofar as it requires, "each line that penetrates primary reactor containment and is neither part of the reactor pressure boundary nor connected directly to the containment atmosphere, shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation."

Technical Evaluation

The containment isolation function is, in general, not affected by the EPU. However, several issues were examined as part of this review.

The licensee proposes to add a new TS 3/4.7.1.7, "Atmosphere Dump Valves." The ADVs are containment isolation valves in a penetration flow path which is part of a closed system. The licensee proposes a 72-hour allowed outage time for these valves. This is consistent with Section 3.6.3 of NUREG-1432, Volume 1, Revision 3, "Standard Technical Specifications Combustion Engineering Plants," June 2004.

The bases for this TS state that the ADVs must be capable of manual isolation. Reference 9 clarifies that this refers to both remote manual and local manual isolation. GDC 57 requires that closed system isolation valves must be capable of remote manual isolation. Therefore, the licensee's proposed TS complies with GDC 57 and is acceptable with respect to isolation capability.

Summary

The NRC staff has reviewed the licensee's assessment of the containment systems and concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The NRC staff also concludes that the containment systems will continue to meet the requirements of GDCs 16, 50, and 57 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; and GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

Waterford 3 subcompartment analyses are discussed in UFSAR Section 6.2.1.2. Section 2.5.2.2 of Reference 1 and Reference 6 discuss changes to these analyses for the EPU.

The licensee determined that the mass and energy releases were higher for the EPU for only one case: the 350 square inches RCS discharge leg break into the reactor cavity. The licensee analyzed the resulting pressurization from this break and determined that the resulting loads were well within limits. The licensee used previously-accepted methods for these calculations.

The subcompartment pressurization analyses are, therefore, acceptable.

Summary

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release and concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

Section 2.5.2.1 of Reference 1 deals with the containment functional design. The containment functional design consists of the response of the containment to two postulated DBAs, the LOCA and the MSLB.

The analysis of both events is divided into two parts. First, the mass and energy discharged into the containment is determined. Using this information, the containment response (pressure and temperature) is then determined. The containment peak pressure and temperature must be less than the containment pressure and temperature acceptance criteria. These values for Waterford 3 are, respectively, 44 psig and 263 EF (FSAR Section 3.8.2.3, "Loads and Load Combinations").

The containment response to the LOCA and the MSLB were previously calculated to support Waterford 3 License Amendment 165, which proposed to revise the number of operable fan coolers required by the Waterford 3 TSs. In order to revise the required number of fan coolers, the licensee reanalyzed the LOCA and the MSLB accident. In Amendment 165, the licensee calculated the mass and energy data for the LOCA at EPU conditions. The MSLB mass and energy release data were calculated for Amendment 165 at the pre-EPU licensed power level.

The mass and energy calculations for both the LOCA and the MSLB use analytic methods described in Section 6.2.1 of the Waterford 3 UFSAR. These methods were used to support License Amendment 165 and approved by the NRC during that review. The containment response is calculated with the GOTHIC (Generation of Thermal Hydraulic Information for Containments) computer code, which is discussed further below.

Use of GOTHIC

GOTHIC is a thermal hydraulic computer program for nuclear power plant containments and was developed by Numerical Applications, Incorporated (NAI) for EPRI. In the license amendment request for Amendment 165, the licensee stated that:

> GOTHIC is fully qualified under the NAI QA [quality assurance] program which conforms to the requirements of Appendix B to 10 CFR Part 50 with error reporting in accordance with 10 CFR Part 21.

GOTHIC 5.0 was used for License Amendment 165. GOTHIC 7.0 (GOTHIC Containment Analysis Package Version 7.0 Technical Manual NAI 8907-06 Numerical Applications, Inc., Revision 12, July 2001) was used for the containment EPU calculations. The licensee stated that GOTHIC 7.0 was used in the same manner as GOTHIC 5.0, (i.e., no new code features or models are being applied). The licensee compared the two versions of the code and reported close agreement in predicting the containment accident pressure. Since no new models were used and reasonable agreement between the two versions of GOTHIC was obtained, the staff finds the use of GOTHIC 7.0 for this application to be acceptable.

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss-of-Coolant

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on GDC 50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment design margin is maintained, and 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

LOCA Mass and Energy Release

The calculation of the mass and energy discharged into the containment following a LOCA at EPU conditions was performed by the licensee in support of License Amendment 165, which was found acceptable in a letter to the licensee dated July 6, 2000 (ML003731172).

LOCA Containment Peak Pressure and Temperature Calculations

The containment peak pressure and temperature following a postulated DBLOCA were calculated using the GOTHIC 7.0 computer program as discussed in Section 2.6.3 of this SE. The following table provides the results of these calculations.

	EPU	Acceptance Limit
Peak Pressure (psig)	35.16*	44
Peak temperature (EF)	254.4	269.3
Pressure at 24 hours (psig)	15.94	16.62 (½ calculated peak)*

* The LOCA that results in the peak 24-hour pressure is different from the LOCA that results in the maximum pressure.

Reference 6 describes changes made to the methods used for these calculations from the UFSAR calculations. These are: modification of the performance of the shutdown heat exchanger and CS delay time.

The shutdown heat exchanger cools the CS flow during the recirculation mode. The licensee has used the GOTHIC 7.0 heat exchanger model with heat transfer coefficients (HTCs) obtained from a more detailed calculation. The UFSAR analyses used constant HTCs. The EPU heat exchanger HTCs are a function of the spray water temperature.

The licensee included an additional one second delay time in the analysis to account for the presence of 4 ft^3 of noncondensible gas in the CS piping.

These changes are reasonable modifications and are acceptable.

Since the calculations were done with acceptable methods and assumptions, the LOCA containment peak temperature and pressure calculations are acceptable.

Summary

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU, and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated LOCA.

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Rupture

Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the mass and energy release rate calculations, and the single-failure analyses performed for steam and FWL isolation provisions, which would limit the flow of steam or FW to the assumed pipe rupture. The NRC's acceptance criteria for mass and energy release analysis for secondary system pipe ruptures are based on GDC 50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena, and containment response; and the conservatism of the model and the values of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

Technical Evaluation

MSLB Mass and Energy Release into Containment

The licensee calculated the mass and energy release into the containment due to an MSLB using the SGNIII computer program. SGNIII has been previously used for Waterford 3 MSLB analyses. The analysis assumptions are described in UFSAR Section 6.2.1.4. The staff has re-examined these assumptions and determined that they are acceptable for the EPU.

MSLB Containment Analysis

The licensee analyzed the containment response to the postulated design basis MSLB accident using the GOTHIC 7.0 code. A description of the model and assumptions is given in Section 6.2.1.4 of the UFSAR. The results of this analysis are given in the following table.

	EPU	Acceptance Limit
Peak Pressure (psig)	41.88	44
Peak temperature (EF)	394.7	413.5*

* Note that the acceptance criterion for containment temperature for the MSLB is different from that for the LOCA. This is because they are based on environmental qualification criteria. Reference 15 states that these criteria have consistently been used as acceptance criteria for containment analysis. However, these containment calculations also serve the purpose of verifying containment structural adequacy. Reference 15 states that calculations show that even at these high containment atmosphere temperatures, the containment structure remains below its design temperature.

Therefore, the results of the MSLB accident calculations are acceptable.

<u>Summary</u>

The NRC staff has reviewed the mass and energy release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addressed the effects of the proposed EPU. Based on this, the NRC staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated secondary system pipe ruptures.

2.6.4   Combustible Gas Control in Containment

<u>Regulatory Evaluation</u>

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas concentrations, and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; GDC 42, insofar as it requires that systems required by

GDC 41 be designed to permit appropriate periodic inspection; and GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing.

Technical Evaluation

On October 16, 2003, NRC issued a revision to 10 CFR 50.44. This revision eliminates the need for hydrogen recombiners and backup hydrogen vent and purge systems. In a letter dated December 19, 2003, the licensee proposed a change to the Waterford 3 TSs, which would delete the TS requirements related to hydrogen recombiners and hydrogen monitors. The NRC approved these changes in a letter to the licensee dated March 6, 2004.

The EPU does not affect the conclusions of the March 6, 2004, letter.

Summary

The EPU does not affect the conclusion of the March 6, 2004, letter from NRC to Entergy approving the proposal to delete the TS requirements related to hydrogen recombiners and hydrogen monitors.

2.6.5 Containment Heat Removal (Emergency Core Cooling System and Containment Spray System Pump Net Positive Suction Head)

Regulatory Evaluation

Fan cooler systems, spray systems, and RHR systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps, and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2 as supplemented by Draft Guide (DG) 1107.

Technical Evaluation

Section 6.3.2.2.2.3 of the Waterford 3 UFSAR describes the NPSH calculations for the ECCS and the CS pumps. Reference 6 states that:

> The NPSH calculations for the emergency core cooling system pumps and the CS pumps do not require a revision to support the extended power uprate….

Since no changes were necessary to the NPSH calculations for the ECCS and CS pumps, these calculations continue to satisfy the appropriate requirements of RG 1.1 and SRP Section 6.2.2 and are, therefore, acceptable for the EPU.

Summary

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the systems will continue to meet GDC 38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Pressure Analysis for Emergency Core Cooling System Performance Capability

Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the reactor vessel to reflood and, thereby, cool the reactor core. The core flooding rate will increase with increasing containment pressure. The NRC staff reviewed analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The NRC staff's review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure. The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on 10 CFR 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR Part 50, Appendix K. Specific review criteria are contained in SRP Section 6.2.1.5.

Technical Evaluation

Section 6.2.1.5 of the SRP and BTP CSB 6-1 provide guidance on the calculation of the LOCA minimum containment pressure calculation. This pressure is used in determining the core reflooding rate in the calculation of the peak cladding temperature (PCT) in order to demonstrate compliance with the criteria of 10 CFR 50.46.

The licensee has made conservative changes (from the UFSAR values) to the values of several input parameters. These are listed in the table below.

Parameter	Pre-EPU	EPU
Minimum RWSP/Spray Temperature (EF)	55	50
Maximum Spray Flow, Two Pumps (gpm)	4180	4500
Minimum Initial Containment Pressure (psia)	14.375	14.025
Minimum Initial Containment Temperature (EF)	100	90

The licensee has proposed including the minimum initial containment temperature of 90 EF in the Waterford 3 TSs. See Section 3.0 of this SE.

The licensee states that some conservative changes were made to the description of the containment heat sinks.

A sensitivity study discussed by the licensee in Section 2.12.3.1 of Reference 1 found that the assumption of no assumed failure of active safety-related equipment gave the most conservative results, since it maximizes the safety injection that spills into the containment, which minimizes the containment pressure.

Since the changes made by the licensee for the EPU analyses and the single failure assumption are conservative, the staff finds the minimum pressure calculation to be acceptable.

Summary

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that the licensee has adequately addressed this area of review to ensure that the requirements in 10 CFR 50.46 regarding ECCS performance will continue to be met following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to minimum containment pressure for ECCS performance.

2.6.7 Generic Letter 96-06

Regulatory Evaluation

By NRC GL 96-06, sent on September 30, 1996, the holders of operating licenses for nuclear power reactors were requested to determine: "... (2) if piping systems that penetrate the containment are susceptible to thermal expansion of fluid so that overpressurization of piping could occur."

Technical Evaluation

The NRC staff requested that the licensee evaluate the effect of the EPU on the potential for thermally-induced overpressurization of isolated water-filled piping sections in containment penetrations. This issue was addressed in NRC GL 96-06. The licensee responded to this GL in correspondence dated January 28, 1997 (9701310030), October 17, 1997 (9710220200), December 22, 1997 (9712290004), October 30, 1999 (9811030136), and April 5, 2000 (ML003703694). The NRC staff found the licensee's resolution of this issue acceptable in a December 22, 2000 (ML003780093), letter to the licensee.

The EPU containment temperatures for both the LOCA and the MSLB are greater than the temperature assumed by the licensee for the GL 96-06 penetration overpressurization evaluations (260 EF). Reference 15 states that this is acceptable since the assumption can be made that the steam in the containment atmosphere will condense on the pipe. The saturation temperature at the partial pressure of steam inside the containment was determined to be less than 260 EF. Therefore, the pre-EPU GL 96-06 evaluations remain bounding and the resolution of GL 96-06 is valid for the EPU.

Summary

The pre-EPU GL 96-06 evaluations remain bounding and the resolution of GL 96-06 is valid for the EPU.

Conclusion

The NRC staff has reviewed the analysis of containment DBA and finds the licensee's analysis methods and the results acceptable since acceptable methods and conservative assumptions were employed, and the applicable regulations remain satisfied. Proposed TS 3/4.6.1.5, 3/4.7.1.7, and 5.2 are acceptable.

2.7 Habitability, Filtration, and Ventilation

Fission product removal systems that operate in conjunction with the fission product control systems following a design basis accident include the engineered safety features cleanup system and various other filtration and ventilation systems. The licensee analyzed the systems, at EPU conditions, for the LOCA and Fuel Handling Accident consistent with the current licensing basis. The NRC staff's review and evaluation of these systems were done consistent with the above licensing basis and are discussed in Section 2.7.

The licensee had, by Reference 11, decided on a full-scope implementation of an AST, as permitted by 10 CFR 50.67, "Accident source term," for calculating accident offsite doses and doses to CR personnel. This request was reviewed by the NRC staff and the amendment was issued on March 29, 2005 (Reference 73).

However, the full-scope implementation of an AST does not change the conclusions reached in this section.

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviews the CR habitability system and CR building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review is to ensure that the CR can be maintained as the backup center from which technical support center personnel can safely operate the plant in case of an accident. The NRC staff's review focuses on the effects of the proposed EPU on the radiation doses, toxic gas concentrations, and estimates of airborne contamination. The NRC staff's acceptance criteria for the CR habitability system is based on (1) 10 CFR Part 50, Appendix A, GDC 19 for maintaining the CR in a safe, habitable condition during accidents by providing adequate protection against radiation; and (2) RG 1.95 (February 1975) and RG 1.78 (June 1974) for accommodating the effects of and being compatible with the postulated accidents, including the effects of the release of toxic gases. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of Reference 31.

Technical Evaluation

For CR habitability, the staff reviewed the CR ventilation system and control building layout and structures as described in Waterford 3 UFSAR and the licensee's submittal in Reference 1 regarding CR habitability. The objective of the staff's review is to assure that plant operators are adequately protected against the effects of accidental release of toxic and radioactive gases. A further objective is to assure that the CR can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident.

The NRC staff accepts the licensee's assessment that the proposed power uprate does not affect the normal ambient conditions inside the CR and the power uprate does not also impact CR conditions during a non-radiological events, such as toxic gas release. In References 11 and 14, the licensee performed AST analyses for the following design-basis accidents that could result in significant CR and offsite doses: LBLOCA, SBLOCA, MSLB inside containment, SGTR, MSLB/Feedwater Line Break outside containment, CEA Ejection, FHA, RCP Seized Rotor/Sheared Shaft, Inadvertent ADV Opening, Excess MS Flow with LOOP, and letdown line break. The licensee concluded that the analyses demonstrate that using AST methodologies, post-accident CR and offsite doses at the uprated power are in compliance with GDC 19 and 10 CFR 50.67. The staff's independent evaluation agrees with the licensee's conclusions. Therefore, the staff finds this acceptable.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CR habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concluded that the licensee has adequately accounted for 1) the toxic gas in the current design, which does not change with the power uprate, and 2) the radioactive gases that would result from the proposed EPU. The NRC staff further concluded that the CR habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the CR habitability system will continue to meet the requirements of 10 CFR Part 50, Appendix A, GDC 19 and RG 1.95 (February 1975) and RG 1.78 (June 1974). Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CR habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or postaccident air-cleaning systems) for the fuel-handling building, CR, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focuses on the effects of the proposed EPU on system functional design, environmental design, and provisions to inhibit off design temperatures in the adsorber section. The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on (1) 10 CFR Part 50, Appendix A, GDC 19 for the design of systems for habitability of the CR under accident conditions; (2) limiting the post-accident radiological releases to below the guidelines of 10 CFR Part 100; (3) RG 1.52, Revision 2, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants;" and (4) 10 CFR Part 20, "Standards for Protection against Radiation." Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

Containment

Primary containment vessel structure consists of a cylindrical steel pressure vessel with hemispherical dome forming a continuous leak tight free standing steel shell. It is completely enclosed by the reinforced concrete Shield Building having a cylindrical shape with shallow dome roof. An annular space is provided between the primary containment vessel and the Shield Building and clearance is also provided between the containment vessel and the Shield Building dome.

The operation of the CSS reduces iodine concentrations and containment atmosphere temperature and pressure. The Containment Atmosphere Release System (CARS) is provided to purge containment at low containment atmosphere pressure. Its operation following a DBA allows fission products to be released to the Shield Building annulus for fission product removal by the Shield Building Ventilation System (SBVS). The Containment Atmosphere Purge (CAP) System is not used following a DBA. The containment vacuum relief system is used to prevent excess external pressure on the primary containment steel shell.

The operation of the CSS has been evaluated and found to be adequate to support the EPU to reduce iodine concentrations and containment atmosphere temperature and pressure as a function of fission product control system. The CARS is operated following a DBA when containment pressure has reduced sufficiently to allow fission products to be released to the Shield Building annulus for fission product removal by the SBVS. The CARS and the SBVS have been evaluated and found to be adequate to support the EPU. The CAP System has been evaluated and found to be adequate to support the EPU in reducing the level of radioactive contamination in the containment atmosphere below the limits of 10 CFR Part 20 to allow personnel access to the containment. Containment structures are maintained intact since the calculated containment pressures following a LOCA and MSLB for EPU conditions are within the acceptance criteria on containment pressure.

Fuel-Handling Building

The spent fuel pool building ventilation system at Waterford 3 is no longer classified as an ESF cleanup system as discussed in License Amendment 176 (TAC No. MB2462). The licensee's analysis of the FHA inside the SFP took no credit for holdup or filtration, but instead assumed an immediate radiological release directly to the environment. All other assumptions were the same as in the Waterford 3 FSAR, including basing the core inventory on 3844.3 MWt. The analysis to support the TS change showed that the CR and offsite doses resulting from an FHA without high-efficiency particulate air (HEPA) filtration or charcoal adsorption remained well within the regulatory guidelines. This analysis will not be impacted by EPU operation because the analysis was performed for a power level of 3,844.3 MWt, which is bounding for the EPU power level including an allowance for measurement uncertainties. An analysis of the FHA in the SFP demonstrates that acceptable dose results are obtained assuming no isolation or filtration functions.

Control Room

For the AST doses, the HEPA filtration and charcoal adsorption capabilities will remain acceptable, as described in Reference 73, to maintain CR doses below the requirements of 10 CFR 50, Appendix A, GDC 19. The licensee stated that the current analysis shows that charcoal heating due to radioactive decay and charcoal oxidation is insignificant in the CR emergency filtration system. The EPU will result in a small increase in the amount of radioactive material that collects in the charcoal and HEPA filters. The licensee's assessment shows that 1) the increase in the amount of radioactive material heat loading is small, 2) the additional radioactive material will not impact the existing analysis, 3) no additional ventilation is required during idle periods, 4) the charcoal filtration system will not be impacted by the EPU operating conditions, 5) the EPU does not introduce any additional failure modes or operational hazards, and 6) the system will continue to meet its existing design basis requirements.

The licensee has also stated that 1) the EPU has no impact on CR parameters that affect the operation of the air conditioning system, 2) the heating and cooling loads will not change, and 3) the required air flow rates will remain adequate to ensure the required positive pressure is maintained in the CR.

Shield Building

Additional fission product control is achieved following a design basis accident by the maintenance of a negative pressure inside the Shield Building annulus by the SBVS. A partial vacuum inside the annulus prevents outleakage through the concrete structure and thus provides control over the release of fission products to the outside environment. The SBVS is designed to fulfill the following functions: a) maintain the annulus pressure below atmospheric during and following a LOCA inside containment, and b) adequately mix, dilute, holdup, and filter radioactive materials in the annulus atmosphere prior to environmental discharge to ensure that 10 CFR Part 100 offsite dose exposures are not exceeded.

The licensee states that the EPU operation will result in increased LOCA source terms and slightly higher SBVS filter loading and bypass. With an assumed CR in-leakage of 100 cfm for the AST, which bounds the tracer gas test results of 79 cfm in recirculation mode and 36 cfm in the pressurized mode (Reference 11), the CR doses will remain within regulatory requirements. The licensee has addressed this issue in accordance with GL 91-18, Revision 1, October 8, 1997, "Information to Licensees Regarding NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions." The offsite doses remain within the regulatory requirements for the EPU using the design basis Technical Information Document TID-14844 core isotropic source term.

The current shield building ventilation system analysis was performed for a power level of 3,865 MWt, which bounds the EPU power level. Based on this, the HEPA filtration and charcoal adsorption capabilities will remain acceptable to maintain post accident doses below the guidelines of 10 CFR Part 100. The existing shield building analysis for charcoal mass loading and heating was performed at a power level that bounds the EPU power level. The filter loading and heat-up for EPU conditions are bounded by the existing analyses, and the current cross flow will be adequate to ensure the charcoal in the idle train does not overheat.

The EPU will have no impact on SBVS operational parameters. The exhaust air flow rate will remain adequate to ensure the required negative pressure is maintained. Also, the recirculation mode of operation will remain adequate to ensure proper mixing, dilution, holdup, and filtration of all airborne radioactive material that leaks into the Shield Building annulus. The EPU will not introduce any additional failure modes or operational hazards. Therefore, the system will continue to meet its existing design basis requirements.

The staff agrees with the assessment that CR heating, ventilation and air-conditioning system, controlled ventilation area system, and shield building atmosphere cleanup systems are adequate to support EPU operation.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in postaccident environments following implementation of the EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of 10 CFR Part 50, Appendix A, GDC 19, 10 CFR Part 20, 10 CFR Part 100, and the guidance of RG 1.52 Revision 2. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System

Regulatory Evaluation

The CR area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of CR components during normal operation, AOOs, and DBA conditions. The NRC staff's review of the CRAVS focuses on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review includes the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC staff's acceptance criteria for the CRAVS are based on (1) RG 1.95 (February 1975) and RG 1.78 (June 1974) for the CRAVS being designed to accommodate the effects of and to be compatible with the anticipated environmental conditions; and (2) 10 CFR Part 50, Appendix A, GDC 19 for providing adequate protection to permit access and occupancy of the CR under accident conditions. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

The NRC staff has reviewed the licensee assessment that EPU operating conditions do not increase the cooling or heating loads within the CR envelope, the existing cooling coils and their associated flow rates are adequate to maintain the required environmental conditions and pressurization requirements, and the current electrical and instrumentation and controls requirements including instrument setpoints will not be affected. The independent trains of equipment provide redundant capacity to assure the safety functions of HVAC following a single failure. The EPU does not introduce any additional failure modes or operational hazards. The current system design for toxic chemical isolation, withstanding seismic events, and withstanding a single active failure will continue to meet the design basis requirements following implementation of the EPU.

The CR HVAC System can adequately support the EPU. The EPU will not change system operating parameters, introduce additional failure modes, or introduce additional operational hazards; therefore, the system will continue to meet its existing design basis requirements.

The AST LOCA dose has been evaluated and found to be within regulatory requirements (Reference 73). The HEPA filtration and charcoal adsorption capabilities will remain acceptable to meet the requirements of 10 CFR Part 50, Appendix A, GDC 19. Any increase in the filter loading and heating for the uprated conditions is accommodated by the existing system design margin, which is sufficient to account for the increase. The current cross flow is designed with sufficient margin to account for the small increase and will be adequate to ensure the charcoal in the idle train does not overheat. Therefore, the filter loading and heat-up will be slightly impacted by EPU conditions, but the current cross flow will be adequate to ensure the charcoal in the idle train does not overheat. Thus, the EPU will not introduce any additional failure modes or operational hazards, and the system will continue to meet its existing design basis requirements.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of the CR personnel and to support the operability of CR components. The NRC staff concludes that the licensee has adequately accounted for the increase of radioactive gases that would result from the proposed EPU and changes to parameters affecting environmental conditions for CR personnel and equipment. The NRC concluded that the CRAVS will continue to provide an acceptable CR environment for safe operation of the plant following implementation of the proposed EPU (Reference 73). The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to meets the requirements. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of 10 CFR Part 50, Appendix A, GDC 19, and RG 1.95 (February 1975) and RG 1.78 (June 1974). Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.3.2 Reactor Auxiliary Building Normal Ventilation System

The controlled ventilation area system (CVAS) is designed to provide filtration of exhaust air from areas of the Reactor Auxiliary Building (RAB) that contain certain ECCS pumps (such as HPSI, LPSI, CSS) and shutdown heat exchangers.

The RAB Normal Ventilation System is not required to operate following a DBA and, therefore, is not designed to safety or seismic requirements. The RAB Normal Ventilation System will not be adversely impacted by operation at the proposed increase in reactor thermal power. There is no expected increase in cooling or heating loads within the RAB areas cooled by the normal ventilation system; therefore, the existing electrical and I&C requirements, including instrument setpoints, will not be affected by the EPU. The existing cooling coil and its associated flow rates will remain adequate to maintain the required environmental conditions and pressurization requirements. The major components provide operating margin to assure the functions of cooling to maintain space temperatures and pressurization to maintain proper air flow. The RAB normal exhaust charcoal filtration unit has significant margin given the expected leakage and normal operation source terms. The licensee stated in a telephone call that the calculation RAC26 addresses the issue of RAB doses under EPU conditions. It looked at average RCS concentrations for EPU conditions compared to the values originally used to evaluate RAB normal HVAC charcoal loading. Assuming the worst case RCS concentrations, there would be little difference between pre-EPU and post-EPU conditions since the RCS activity limit per Technical Specifications is not being revised. Based on the methodology used to assess the RAB Normal HVAC system, AST would not impact this information since it is only the normal concentration and distribution of radioisotopes (specifically radioiodines) that impacts the RAB normal HVAC system. Thus, the current RAB dose calculations will bound the doses under EPU conditions. In addition, the expected releases from the RAB areas during normal operation are small, and any EPU changes will remain within the regulatory requirements.

Based on this, the existing charcoal filtration system flow rate, charcoal filter residence time, and filter loading is adequate to maintain radiological design parameters well within design basis requirements. There is no impact on the existing licensing basis of the RAB Normal Ventilation System due to the conservative design of the existing system. The EPU will not introduce any additional failure modes or operational hazards; therefore, the system will continue to meet its existing design basis requirements. A review of the overall system design along with the interaction of support systems (supplemental service chiller water) shows that the system is capable of meeting its design cooling, pressurization, and filtration requirements for EPU operation.

Therefore, the staff finds the licensee’s assessment that the EPU will not introduce any additional failure modes or operational hazards in the CVAS and the proposed EPU acceptable with respect to the CVAS.

2.7.3.3 Spent Fuel Pool Area Ventilation System

Regulatory Evaluation

The function of the SFP area ventilation system (SFPAVS) is to maintain ventilation in the SFP equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel handling accidents. The NRC staff’s review focuses on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC’s acceptance criteria for the SFPAVS are based on meeting the guidelines of 10 CFR Part 100 for offsite doses. Specific review criteria are contained in SRP Section 9.4.2.

Technical Evaluation

The SFP Ventilation System is designed to maintain the SFP areas at a negative pressure during emergency operation, and to provide filtration and charcoal adsorption for the air exhausted from the area assuming a single active failure coincident with a LOOP. The system is also designed to maintain the space temperature in the SFP between 50 °F and 104 °F to ensure proper functioning of instrumentation and controls during normal operating conditions.

The SFP Ventilation System equipment and operational modes will not be adversely impacted by the proposed increase in reactor thermal power. The licensee states that analysis of record shows that the system isolation and filtration/adsorption functions are not needed to mitigate the radiological consequences of a FHA in the SFP. This analysis was performed using a radioactive source term that bounds EPU conditions. The system design inputs used to determine electrical and I&C requirements (including instrument setpoints), system flow rates, filtration requirements, and negative pressure setpoints will not change as a result of operation at the EPU level. The existing exhaust fans, filter trains, and their associated control components will remain adequate to maintain the required environmental conditions and pressurization requirements.

The EPU will not adversely impact the SFP Ventilation System due to the conservative parameters utilized to establish the building heat loads and to determine the required air flows. The existing system analysis has been reviewed and bounds the anticipated EPU operating conditions.

A review of the overall system design shows that the system is capable of meeting its design pressurization and filtration requirements for the proposed EPU. The existing equipment will perform within the existing design basis requirements at the proposed EPU operating conditions. The EPU will not introduce any additional failure modes or operational hazards; therefore, the system will continue to meet its existing design basis requirements.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, to permit personnel access, control airborne activity in the area, control release of gaseous radioactive effluents to the environment, and provide the appropriate containment. Based on this, the NRC staff concludes that the SFPAVS will continue to meet the guidelines of 10 CFR Part 100. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SFPAVS.

2.7.3.4 Turbine Area Ventilation System

Regulatory Evaluation

The function of the turbine area ventilation system (TAVS) is to provide a suitable operating environment for all equipment and personnel during normal operation and permit periodic inspection and testing of system components. The NRC staff's review focuses on the effects of the proposed EPU on the functional performance of the safety-related portions of the system.

Technical Evaluation

The EPU will have no impact on the design and operation of the TAV System. Conservative parameters were used for establishing the heat loads generated in the building and the air flow rates needed to remove the heat. The conservative parameters bound the heat loads anticipated for the EPU.

Summary

The TAVS is not required to mitigate the consequences of a DBA or to provide a safe shutdown of the reactor. Therefore, it is not designed to any safety or seismic requirements. The failure of any system component will not affect any safety-related SSC. However, the NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capacity of these systems to maintain ventilation in the turbine area to permit personnel access for inspection and testing.

Based on this, the NRC staff concludes that the TAVS will continue to provide a suitable operating environment during normal operation and permit periodic inspection and testing.

2.7.3.5 Engineered Safety Features Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS is based on limiting the post-accident radiological releases to below the guidelines of 10 CFR Part 100.

Technical Evaluation

The licensee evaluated the following ESF ventilation systems.

- Emergency Diesel Generator Ventilation System
- Reactor Auxiliary Building Ventilation and Equipment Room Ventilation System
- RAB Cable Vault and Switchgear Areas Ventilation System
- RAB Safety-Related Fan Coolers

The licensee's assessment is that these systems will not be adversely impacted by the proposed EPU. The EPU operating conditions are not adding additional electrical loading above the design loading of the EDGs. The heat generated by the additional radioactive loading of the SBVS and CRAVS charcoal filters is insignificant and will have negligible impact for EPU conditions. There is no expected increase in cooling loads within the areas served by these air handling units.

The heat generated by the additional radioactive loading of the SBVS and CRAVS charcoal filters is insignificant and, therefore, will not have a significant impact for EPU conditions. The largest post-accident heat contributor to the H&V equipment room will be the SBVS ductwork and components operating to recirculate, filter, and exhaust the annulus atmosphere. The post-accident containment temperature profile from operation at EPU conditions will not increase; therefore, the post-accident shield building temperature will not increase above current values. Based on this, the EPU operating conditions will not have a significant effect on the heat load contributors in the RAB H&V equipment room, and the RAB H&V equipment room ventilation system will not be impacted by operation at EPU conditions. The existing system will maintain the equipment room temperature within acceptable values. The EPU will not introduce any additional failure modes or operational hazards. Therefore, the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

The AST analysis, using RADTRAD for offsite and CR dose, considers a leak rate of 0.5 GPM from ECCSs that are recirculated and may leak to locations serviced by the CVAS system in the RAB. While no credit is taken for holdup and dilution in the RAB, CVAS filtration is credited. A flashing fraction of 10 percent is assumed, consistent with RG 1.183.

There is no expected increase in cooling loads within the areas served by the air handling units, with the exception of the SDC heat exchanger rooms. The increased decay heat for EPU conditions during normal shutdown will increase the SDC heat exchanger CCWS outlet temperature, which will increase the CCWS piping contribution to the room heat load. The licensee states that the impact of this higher heat load on the SDC heat exchanger room cooler will be evaluated. The process piping systems in the RAB areas will not experience increases in fluid temperatures during normal and post-accident operation as a result of EPU (See CCWS discussion in Section 2.2 of this SE). The heat loads removed include electrical switchgear, pump case and motor heat, and instrumentation heat losses to the ambient air. These loads are not affected by EPU. The RAB safety-related fan coolers are supplied by the Essential Chilled Water System, which will not be impacted by EPU operating conditions. The existing cooling coils and their associated flow rates will remain adequate to maintain the required environmental conditions. The EPU will not introduce any additional failure modes or operational hazards; therefore, the system will continue to meet its existing design basis requirements. The electrical and I&C requirements including instrument setpoints will not be affected by the EPU.

The RAB Cable Vault and Switchgear Area Ventilation System will not be adversely impacted by the proposed increase in reactor thermal power. There is no expected increase in cooling loads within the areas served by these air handling units. These areas do not contain hot fluid process piping, and the electrical equipment loads are based on the design rating. These loads are not increased by the EPU. In addition, battery hydrogen generation will not increase because the battery loads are not increasing. This means that the existing battery room exhaust flow rate and margin will not require revision. The existing exhaust fan and cooling coils along with their associated flow rates will remain adequate to maintain the required environmental conditions, and the current electrical and instrumentation and controls requirements including instrument setpoints will not be affected. The system is designed with two independent trains that provide redundant capacity to assure the safety functions of maintaining adequate environmental conditions and hydrogen removal.

The RAB Cable Vault and Switchgear Area Ventilation System will adequately support operation at EPU conditions. The EPU will not change system operating parameters, introduce additional failure modes, or introduce additional operational hazards; therefore, the ventilation system as currently designed has sufficient margin to meet its functional requirements at the expected EPU operating conditions.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The NRC staff also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESFVS will continue to limit the post-accident radiological limits below the guidelines contained in 10 CFR Part 100. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESFVS.

2.8 Reactor Systems

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control elements. The NRC staff reviewed the fuel system to ensure that (1) the fuel system is not damaged as a result of normal operation and AOOs, (2) fuel system damage is never so severe as to prevent control element insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The staff's review of the fuel system design is focused mainly upon the performance of the fuel rods and cladding under the steady-state and transient operating conditions that would be characteristic of the Waterford 3 core, when operating at EPU conditions. The fuel assembly designs that are currently in use at Waterford 3 are retained for the 3716 MWt EPU core. These assemblies, fabricated at the Hematite, MO and Columbia, SC facilities, have the Guardian™ grid feature with either an HID-1L/Zr-4 top spacer grid or an Inconel top spacer grid.

The staff's review of the fuel rod design considers external pressure, differential expansion of the fuel and clad, fuel swelling, clad creep, fission and other gas releases, internal helium pressure, thermal stress, pressure and temperature cycling, and FIVs.

The Waterford 3 reactor core also contains 87 CEAs, each of which has four control elements, placed in a 4.050 inch square array, and an additional element in the center of the array.

Many key fuel rod design-related parameters are not changed as power is uprated to the EPU level. The maximum fuel rod axially-averaged fluence remains at 13.7 x 10^{21} n/cm^2 (E > 0.821 MeV), minimum flow rate continues to be 148 million lbm/hr, peak rod axially-averaged burnup is still 60,0000 MWD/MTU, and the maximum residence time stays at 41,200 effective full-power hours (EFPH). However, nominal core inlet temperature drops from 545 to 543 °F, and peak linear heat rate (PLHR) is reduced to between 12.9 kW/ft (for rods > 50 MWD/kgU) and 13.2 kW/ft (for rods # 50 MWD/kgU) from 13.5 kW/ft.

Fuel Rod Clad Collapse

The fuel rod clad collapse limit can be affected by an increase in core power rating, since the higher power level results in higher fuel operating temperatures, and an increase in oxide thickness levels. The licensee has applied an NRC-approved collapse performance methodology and the CEPAN (References 40 and 41) computer program to determine that the minimum collapse time for any fuel rod in the reactor will be greater than or equal to the 41,200 EFPH residence time specified for the 3716 MWt EPU conditions. Thus, the rod collapse limits are satisfied for the specified residence time.

Fuel Rod Clad and End Cap Weld Fatigue

The fuel rod clad and end cap weld fatigue limit is affected by an increase in the core power rating, as the higher power level causes higher fuel operating temperatures, resulting in an increase in cyclic strain levels. To show that the fuel system is not damaged due to excessive fatigue from normal operating and upset transient conditions, the fuel rod clad cumulative fatigue damage at EOL must be more than twenty percent below the point of predicted failure.

The licensee has performed a fatigue analysis, evaluating rod and end cap weld fatigue as a function of burnup, and confirmed that rod fatigue limits can be satisfied for core designs having an EOL burnup of 60,000 MWD/MTU.

Fuel Clad Stress

Two criteria are applied to show that the fuel system will not be damaged due to excessive fuel clad stress:

1. Maximum tensile stress in the clad and in the end cap welds < 2/3 minimum unirradiated yield strength of the material at the applicable temperature.
2. Maximum compressive stress in the clad and in the end cap welds < minimum unirradiated yield strength of the material at the applicable temperature.

The licensee has used an approved methodology, accounting for the local power duty during AOOs, to evaluate margin to the two clad stress limits. The results of this evaluation indicate that the fuel will continue to meet the clad stress limits for the uprated power conditions.

Clad Strain

Two clad strain limits are applied to assure that the fuel system will not be damaged due to excessive fuel clad strain:

1. Net unrecoverable circumferential strain in the fuel rod clad must not exceed 1 percent, as predicted by calculations that account for clad creep, pellet swelling, and pellet/clad differential thermal expansion under normal operating conditions.

2. Total circumferential strain in the fuel rod clad for rods having axially-averaged burnups greater than or equal to 52,000 MWD/MTU must not exceed 1 percent under normal operating conditions.

The licensee has used an approved methodology, accounting for the local power duty during AOOs, to evaluate margin to the two clad strain limits. The results of this evaluation indicate that the fuel will continue to meet the clad strain limits for the uprated power conditions.

Plenum Spring Seizure

The fuel system is designed such that it will not be damaged due to excessive deflection of the plenum spring. Deflection of the plenum spring at any point in the fuel lifetime must not be great enough to cause it to seize within the cladding tube inside diameter.

The licensee has used approved methodology to evaluate diametral clearance in the fuel rod over the design life. The results of this evaluation indicate that the plenum spring will not seize within the cladding tube for the uprated power conditions.

Rod Maximum Internal Pressure

The licensee has evaluated the fuel rods, under EPU conditions, using FATES3B, which is based upon the Westinghouse CENP fuel evaluation model (References 42, 43, 44, and 45). The power history assumed in this analysis encompassed the power and burnup level typical of the peak fuel rod of each burnup interval, extending from beginning of cycle (BOC) to EOC. None of the fuel rod internal pressures is calculated to exceed the no-clad-liftoff pressure

(Reference 46) for any of the EPU cycles. These results support a maximum LHR of 13.2 kW/ft to a peak rod average burnup of 50 GWD/MTU, and 12.9 kW/ft at higher burnups.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control element insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC 10, GDC 27, and GDC 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control element patterns and reactivity worths, criticality, burnup, and vessel irradiation. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; GDC 12, insofar as it requires that the reactor core be designed to assure that power oscillations that can result in conditions exceeding SAFDLs are not possible or can be reliably and readily detected and suppressed; GDC 13, insofar as it requires that I&C be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The Waterford 3 Power Uprate can affect key nuclear safety parameters, such as core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. Many of these parameters are used in accident analyses, reported in Reference 1 and Chapter 15 of the SAR. The designs of the fuel assemblies currently loaded in the Waterford 3 core are unchanged for operation at the EPU power level.

The licensee's nuclear design analyses are based upon an assumed core power level of 3716 MWt, and typical values for the mechanical and thermal hydraulics data. With the exception of core power level, all assumed parameter values are within currently licensed limits. Furthermore, the licensee states that the final parameter values will be determined via the cycle-specific reload process, as a confirmation that they're appropriate for the operating conditions of each specific cycle. The EPU physics data and other nuclear design parameter values are verified to be applicable to the range of fuel management patterns that are expected to exist in future core designs. The EPU does not require any changes to current nuclear design methods and models.

The result is that fuel design limits would not be violated during normal or anticipated operational transients. Specifically, postulated reactivity accidents would not lead to a breach of the reactor coolant pressure boundary, nor jeopardize the coolability of the core. These assertions are tested and confirmed by the accident analysis results presented in Section 2.13 of Reference 1.

Summary

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to or a justified extrapolation from proven designs, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components, during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and ATWS events. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and GDC 12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations that can result in conditions exceeding SAFDLs are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The primary thermal-hydraulic design basis is the assurance that the core can meet normal steady-state and transient performance requirements (i.e., the prevention of thermally-induced fuel damage during normal operation and AOOs).

Fuel assemblies of the same design as those currently loaded in the core at Waterford 3 are assumed as the basis for the licensee's EPU thermal and hydraulic design analyses. The nominal channel hydraulic diameter, primary system pressure, minimum core coolant mass flow, and nominal film coefficient all remain unchanged in the EPU analyses. The lower limit on the total reactor coolant flow is assumed in the thermal margin analyses, with uncertainties in system resistance, pump head, and core bypass flow taken in the adverse direction. The engineering heat flux factor and the engineering factor on hot channel heat input both remain at 1.03.

The EPU core has an allowance for up to 100 non-fuel rods, which reduces the total core heat transfer area to 63,767 ft^2 from 63,892 ft^2. Vessel inlet temperature is reduced two degrees, from 545 EF to 543 EF. The average core enthalpy rise increases from 81.5 BTU/lbm to 88.0 BTU/lbm.

The evaluation methodology that is applied for the EPU thermal-hydraulic design is unchanged from the current methodology. Steady-state departure from nucleate (DNB) ratio (DNBR) analyses for EPU core have been performed using the TORC code (References 47 and 48), the CE critical heat flux correlation (References 49 and 50), and the CETOP code (Reference 51).

The RCS operating pressure and the TS minimum RCS flow rate will remain the same for the EPU. The loop coolant temperature associated with the EPU remains within the bounds of the original design temperature for the RCS and the pressurizer. Sufficient core cooling under power uprate conditions is verified by the relevant plant transient and safety analyses, evaluated in Section 2.8.5 of this SE. The licensee's evaluation of the natural circulation cooldown capacity of the RCS for EPU conditions confirms that such a cooldown can be accomplished within the criteria established by Reactor Systems Branch (RSB) BTP 5-1.

The results of the thermal and hydraulic design analyses at EPU conditions indicate that the EPU core satisfies normal operation and transient performance requirements. This conclusion is tested and confirmed in the accident analyses reported in Section 2.13 of Reference 1.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design, and demonstrated that the design has been accomplished using acceptable analytical methods and provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs. Based on the information provided in Reference 1, the staff concludes that the RCS will continue to meet the design requirements, as described in the UFSAR, and that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Element Drive Mechanism

Regulatory Evaluation

The NRC staff's review covered the functional performance of the CEDM to confirm that the system can achieve a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CEDM cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; GDC 23, insofar as it requires that the protection system be designed to fail into a safe state; GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, assuring the capability to cool the core is maintained; GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and GDC 29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs. Specific review criteria are contained in SRP Section 4.6.

Technical Evaluation

The CEDM Control System (CEDMCS) communicates with the Reactor Regulating System (RRS) for automatic control and the control panel, for manual motion control. Motion demand signals are translated into pulses that are sent to the CEDM coils to initiate CEA motion. This system is not credited for reactor trips or other functions related to achieving safe shutdown. The RPS generates the reactor trip signals required for mitigation of AOOs and accidents. CEA motion control is discussed in UFSAR Section 7.7.1.1.

The CEDMs are cooled by a forced air cooling system consisting of four exhaust fans and associated ductwork, dampers, and coolers. The exhaust fans draw air into a shrouded area enclosing the reactor head and CEDMs. Cool air flows across each of the drive mechanisms, and then across water-cooled heat exchangers. The heat exchangers transfer the heat from the air to the CCWS. The cooled air is returned to the containment atmosphere by the exhaust fans. CEDM cooling is discussed in UFSAR Section 9.4.5.

RV temperature is not increased by the EPU. The shroud design is unchanged, and the heat loads seen by the CCWS remain within current design parameters. Containment air temperature also remains unchanged. Consequently, CEDM cooling would not be affected by the proposed EPU conditions.

Events that are postulated to be initiated by CEA control system failures are evaluated in Section 2.13.4 of Reference 1. The results of these evaluations indicate that the applicable acceptance criteria continue to be satisfied under EPU conditions. Furthermore, the CEDMCS, the RRS and the CEDM Cooling System also continue to meet the requirements of GDCs 4, 23, 25, 26, 27, and 29 under EPU conditions.

Summary

The NRC staff has reviewed the licensee’s analyses related to the effects of the proposed EPU on the functional design of the CEDM. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system’s ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system’s design bases will continue to be met upon implementation of the proposed EPU. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the functional design of the CEDM.

2.8.4.2 Overpressure Protection During Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the RPS. The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and RCS relief and safety valves. The NRC's acceptance criteria are based on GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance provided in Matrix 8 of Reference 1.

Technical Evaluation

Overpressure protection for the RCPB during power operation is provided by SRVs and the RPS. The NRC's acceptance criteria are based on GDC 15 for the RCS and associated auxiliary, control, and protection systems being designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and GDC 31 for the RCPB being designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

The licensee has evaluated specific overpressure protection requirements of the ASME Code for the proposed EPU and concluded that all general requirements and component requirements for the pressurizer safety valves (PSVs) and the MSSVs were in compliance with the Code.

The staff has reviewed the licensee's safety analyses related to the effects of the proposed power uprate on the overpressure protection capability of the plant during power operation. Based on the acceptable results of the safety analyses for heatup events, the staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 at an uprated core power of 3716 MWt. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features, and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Overpressure Protection During Low Temperature Operation

Regulatory Evaluation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The NRC staff's review covered relief valves with piping to the quench tank, the makeup and letdown system, and the SDCS, which may be operating when the primary system is water-solid. The NRC's acceptance criteria are based on GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

Technical Evaluation

Low-temperature overpressure protection (LTOP) ensures that the 10 CFR Part 50, Appendix G, pressure vessel brittle fracture limits will not be exceeded during operation in Modes 4 or 5 under conditions of overpressurization. The analysis employs mass and energy injection transients to determine conservative limits of the maximum pressure. For the mass injection transient, an SI actuation is assumed into a solid RCS. For the energy injection transient, a 100 EF difference is assumed between RCS and the SG of an idle loop with inadvertent RCP activation.

Additional heat sources include core decay heat, RCP operation and pressurizer heaters. However, only the decay heat is directly affected (by a small amount) by the power uprate. Pressure relief for either transient is provided through the two relief valves of the SDCS. Only one valve is assumed to be operable.

The maximum pressure calculated for the mass injection transient is 471 psia, and for the heat injection 467 psia. To put these pressures in perspective, consider that the LTOP enable temperature (Reference 52) was set at 200 EF, which is the minimum required by Reference 34 and did not change with the EPU. For the enable temperature, the corresponding maximum acceptable (Appendix G) pressure is 554.1 psia. The relief valve setting is at 430 psia (assuming one relief valve operational), which allows considerable margin for overshoot.

The staff reviewed the proposed values for PTS and LTOP settings for Waterford 3, which accounted for the power uprate to 3716 MWt. Considering the above, the staff finds that the LTOP was analyzed using conservative assumptions and approved methods, and yielded conservative results; therefore, the PTS limits and the LTOP enable temperature and pressure are acceptable.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features, and

(2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the LTOP features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Shutdown Cooling System

Regulatory Evaluation

The SDCS is used to cool down the RCS following shutdown. The SDCS is typically a low pressure system which takes over the SDC function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the SDCS to cool the RCS following shutdown and provide DHR. The NRC's acceptance criteria are based on GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects; GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and GDC 34, which specifies requirements for an SDCS. Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The licensee has evaluated the ability of the SDCS at EPU conditions to achieve shutdown performance, as described in the UFSAR, and the system's capability to achieve cold shutdown conditions per the requirements of RSB BTP 5-1, natural circulation cooldown. When combined with the ADV and EFWS, the plant could reach cold shutdown conditions within 36 hours. The evaluation for the EPU conditions demonstrate an acceptable capability without plant modification.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SDCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system, and demonstrated that the SDCS will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the NRC staff concludes that the SDCS will continue to meet the requirements of GDCs 4, 5, and 34, and RSB BTP 5-1, natural circulation cooling, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SDCS.

2.8.4.5 Nuclear Steam Supply System Design Transients

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME Code, Section III, Division 1, and GDCs 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters, and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered (1) the analyses of FIV, and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the Code-allowable limits. The NRC's acceptance criteria are based on 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes, combined with the effects of normal or accident conditions; GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and GDC15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of Reference 31.

<u>Technical Evaluation</u>

In Reference 1, the licensee has evaluated the NSSS design transients to account for any impacts of the power uprate. The NSSS design transients are traditionally developed for fatigue analyses of the various NSSS components using conservative assumptions. The licensee provided a tabulation comparing the plant operating conditions at the current power rating and the proposed NSSS power level of 3716 MWt. The licensee has evaluated the changes in the plant operating conditions and concludes that the existing pressure and temperature limitations remain applicable for the Waterford 3 EPU with the following differences between the current design transient limitations and expected uprate transient responses: (1) the cold leg temperature will experience an increase of nearly 16 °F during a loss of load event, and (2) the pressurizer surge line temperature change during plant trips, loading, and unloading needs to be revised from 110 EF to 114 EF to accommodate the change of the no-load RCS temperature. The licensee has incorporated these changes in its evaluation for the effects on fatigue life. The staff has reviewed the licensee's submittal and finds the licensee's conclusion acceptable.

RCS overpressurization is further discussed in Sections 2.8.4.2 and 2.8.4.3 of this SE.

<u>Summary</u>

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the NSSS design transients. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on fatigue analyses of the various NSSS components, and (2) evaluated the changes in the plant operating conditions and found that the existing pressure and temperature limitations remain applicable for the Waterford 3 EPU. Based on this, the NRC staff concludes that the NSSS design transients, as evaluated with respect to GDC 15, that would be affected by implementation of the proposed EPU will continue to meet GDC 15 requirements following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the NSSS design transients.

2.8.4.6 Station Blackout

Regulatory Evaluation

SBO refers to a complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from alternate AC sources. The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63, which requires that light-water-cooled nuclear power plants must be able to withstand for a specified duration and recover from an SBO. The reactor core and associated coolant, control, and protection systems, including station batteries and any other necessary support systems, must provide sufficient capacity and capability to ensure that the core is cooled and appropriate containment integrity is maintained in the event of an SBO for the specified duration. The review of SBO includes the effects of the EPU on systems relied upon for core cooling in the SBO coping analysis (e.g., condensate storage tank (CST) inventory, controls and power supplies for relief valves, and RHR system) to ensure that the effects are accounted for in the analysis. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2.

Technical Evaluation

In Reference 12, the licensee provided the results of its detailed evaluation relative to the EPU affecting the plant coping capability during an SBO. The SBO event is postulated for four hours at Waterford 3; the only power source available during a SBO is the 125 volt DC onsite power system (i.e. safety related 1E batteries). The safety grade DC power and nitrogen accumulators will support the turbine driven EFW pump to feed SGs from the water available in the seismically-qualified water source in the CSP. The licensee's evaluation of the system impacted by the EPU does not identify any changes to design or operating conditions that adversely affect the ability to provide safe shutdown for an SBO initiated from EPU conditions. However, the total required condensate water will be increased from 80,000 gallons to 82,200 gallons. This is based on maintaining hot standby conditions during the SBO and is well less than the current TS minimum of 170,000 gallons dedicated for EFW system usage.

Summary

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SBO.

2.8.5 Accident and Transient Analyses

2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature, which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation; GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Reference 1 presents analyses for the following events, which are categorized as events that result in an increase in heat removal by the secondary system:

Increase in Steam Flow
Increase in Steam Flow with LOOP
Inadvertent Opening of a SG Relief or Safety Valve
Inadvertent Opening of a SG Relief or Safety Valve with LOOP

Reference 1 does not present analyses for the following events, since the licensee evaluates them as events that are bounded by other analyzed events:

Decrease in FW Temperature
Decrease in FW Temperature with single active failure (SAF)
Increase in FW Flow
Increase in FW Flow with SAF

The results are summarized according to event category (ANS Class II and III, i.e., events of moderate frequency and infrequent events) in the following table:

Section 2.13.	Event	Cate-gory	Result
1.1.1	Decrease in FW Temperature	II	Bounded by Increased MS Flow
1.1.2	Increase in FW Flow	II	Bounded by Increased MS Flow
1.1.3	Increased MS Flow	II	min DNBR = 1.533, at 25.2 sec
1.1.4	Inadvertent Opening of a SG ADV	II	min DNBR > 20, at 85 sec
1.2.1	Decrease in FW Temperature with SAF	III	Bounded by Increased MS Flow with LOOP
1.2.2	Increase in FW Flow with an SAF	III	Bounded by Increased MS Flow with LOOP
1.2.3	Increased MS Flow with LOOP	III	min DNBR = 1.057, at 2.05 sec after LOOP
1.2.4	Inadvertent Opening of a SG ADV (IOSGADV) with LOOP	III	min DNBR = 1.2645, at 2.50 sec after LOOP

The increase in steam flow event is defined as any rapid increase in SG steam flow, other than a steam line rupture. The resulting core cooldown causes a power increase that could lead to violation of a fuel design limit. Automatic protection is provided by the low DNBR and high local power density trips, the low SG water level and pressure trips, the high reactor power trip, and the low pressurizer pressure trip. Direct turbine trip is not assumed.

An increase in MS flow may result from the inadvertent operation of steam system valves (e.g., the turbine admission valves, the turbine bypass valves, the ADVs, or SG safety valves) due to either equipment failure or operator error. The analysis is based upon the assumption that the largest of these valves, a turbine bypass valve in the SBS, is fully opened. This would increase steam flow by approximately 10.8 percent of the full power turbine flow rate. The flow rate of one valve is assumed, in the analysis, to be approximately 12.3 percent of the full power turbine flow rate, at EPU conditions. The analysis results indicate that the minimum DNBR remains greater than 1.26, and the peak LHR does not exceed 21 kW/ft. Therefore, the event does not cause a violation of the SAFDLs.

An analysis for the IOSGADV is also presented. The IOSGADV is assumed to occur at low power (1 MW). The steam release, through the ADV, causes a core cooldown and a power increase that does not exceed six per cent. The results for this event analysis indicate that the minimum DNBR occurs at about the time of maximum power, but remains well above the SAFDL.

The increased MS Flow with LOOP event, a combination of two (AOOs), is classified as an Infrequent Event. When the thermal margin is eroded to the point where the hottest fuel rod is just above the DNBR SAFDL of 1.26, as calculated by the Core Protection Calculator System (CPCS), the LOOP is assumed to occur, and coastdown of the RCPs begins. The minimum DNBR violates the SAFDL and fuel failure is predicted. This event is also described as a LOOP from SAFDL conditions, wherein the Increased Steam Flow AOO is used to bring the plant to the SAFDL condition, which becomes the initial condition for the subsequent loss of forced flow AOO. The licensee has determined the extent of fuel pin failure that will not result in exceeding the regulatory limit for radiological consequences (eight per cent). Cycle-specific fuel failure evaluations for power uprate cores will be performed to ensure that this fuel failure limit will not be exceeded.

Summary

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that for the AOO the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. For the event with a LOOP, SAFDL violation is of sufficiently limited extent that radiological consequences are acceptable. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

Regulatory Evaluation

The steam release resulting from a rupture of an MS pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed responses of the reactor coolant and auxiliary systems; (5) functional and operational characteristics of the RPS; (6) operator actions; (7) core power excursion due to power demand created by excessive steam flow; (8) variables influencing neutronics; and (9) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and GDC 35, insofar as it requires the RCS and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.1.5 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Reference 1 presents analyses for the following events, which are categorized as Steam System Piping Failures:

Steam System Piping Failures, Post-Trip Analysis
Steam System Piping Failures, Pre-Trip Power Excursion

Reference 1 does not present an analysis for the Mode 3 and 4 all rods in (ARI) SLB, since it's bounded by ARI SLB in the current UFSAR, which is assumed to occur at more limiting Mode 2 conditions.

The results are summarized in the following table:

Section 2.13.	Event	Category	Result
1.3.1	Steam System Piping Failures, Post-Trip Analysis	IV	Scram worths are determined such that the maximum fuel failure is 2 percent, due to DNB SAFDL violation. No fuel failure due to centerline melting is allowed.
1.3.2	Mode 3 and 4 ARI SLB	IV	Bounded by UFSAR 15.1.3.2
1.3.3	Steam System Piping Failures, Pre-Trip Power Excursion	IV	The radiological consequences and fuel failure limits of the pre-trip SLB scenario are combined with those of the RTP SLB scenario.

As a Limiting Fault, the Steam System Piping Failure analyses could predict some fuel damage and still meet the acceptance criteria for a Condition IV event. However, the analysis results for the Steam System Piping Failure - Post-Trip analysis indicated that there would be some fuel damage due to centerline melting. This was not acceptable to the staff, since the licensee's fuel response methodology is not approved for modeling centerline melt, such that a coolable geometry can be shown to be maintained in the core, as the fuel rod centers melt and expand. The staff conveyed this concern to the licensee in a teleconference on July 21, 2004. As a result, the licensee agreed to design the core loading (e.g., to build in sufficient scram worth), in each reload core design to assure that none of the analyzed SLB cases would lead to any fuel centerline melting (e.g., PLHR=24kW/ft). Specifically, the licensee stated in Reference 21 that, "Due to differences in the magnitudes of reactivity feedback mechanisms, the rates of heat removal associated with different break areas and LOOP assumptions, the minimum acceptable SCRAM worth would be different for each of the eight RTP SLB scenarios examined. Restrictions will be incorporated in future reload core designs to ensure that the most limiting of the requirements are verified for actual power uprate core designs."

This is one of the events that was reviewed by NRC staff, at the Westinghouse office, in Connecticut. The staff read the documents that detailed the calculation inputs and methods, and, whenever possible, discussed the results and interpretation of results with the engineers who performed the analyses. This event was selected by the NRC staff for a more detailed review, because the licensee's initial submittal predicted that some centerline fuel melting would occur. This event also tests the automatic RPS setpoints and the SI system.

Summary

The NRC staff has reviewed the licensee's analyses of Steam System Piping Failure events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control elements is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to steam system piping failures, with the licensee's statement on reload design restrictions being implemented.

2.8.5.2 Decrease in Heat Removal by the Secondary System

2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of Reference 1.

Technical Evaluation

Reference 1 presents an analysis for the loss of condenser vacuum (LOCV), which is categorized as an event that results in a decrease in heat removal by the secondary system.

Reference 1 does not present analyses for the following events, since they're bounded by these, analyzed events:

Loss of External Load
Turbine Trip

LOOP
Steam Pressure Regulator Failure
Loss of External Load with SAF
Turbine Trip with SAF
LOCV with LOOP

The results are summarized in the following table:

Section 2.13.	Event	Cate-gory	Result
2.1.1	Loss of External Load	II	Bounded by 2.13.2.1.3
2.1.2	Turbine Trip	II	Bounded by 2.13.2.1.3
2.1.3	LOCV	II	max RCS press = 2732 psia max SG press = 1186 psia
2.1.5	Steam Pressure Regulator Failure	II	Bounded by 2.13.2.1.3
2.2.1	Loss of External Load with SAF	III	Bounded by 2.13.2.2.3
2.2.2	Turbine Trip with SAF	III	Bounded by 2.13.2.2.3
2.2.3	LOCV with LOOP	III	Bounded by 2.13.2.1.3

The limiting event in this group of events is the LOCV. An LOCV could result from a failure in the CWS, or the MCES, or in turbine gland packing, and cause the turbine generator to trip. The turbine trip is assumed to cause the FW pumps (FWPs) to trip on low suction pressure.

Closing the turbine stop valves and tripping the main FWPs shuts off the secondary side heat sink, causing the primary and secondary temperatures and pressures to increase. Since no credit is taken for the Steam Bypass Control System (SBCS), which is assumed to be in manual operation, the RCS pressurizes and the reactor trip occurs on high pressurizer pressure.

The analysis results indicate that the overpressure acceptance criteria (110 percent of design pressure), are satisfied.

Summary

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limit will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.2 Loss of Nonemergency Alternating Current Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown, as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Reference 1 does not present analyses for either the LOOP or the Loss of Normal AC Power with SAF, since they're bounded by other analyzed events. The LOOP (Section 2.13.2.1.4) is bounded, with respect to RCS and SG overpressure, by the LOCV event. The LOOP is bounded, with respect to low thermal margin, by the Total Loss of Forced Reactor Coolant event. The Total Loss of Forced Reactor Coolant event is evaluated in Section 2.8.5.3.1 of this report.

Summary

The NRC staff has reviewed the licensee's analyses of the loss of nonemergency AC power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limit will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of nonemergency AC power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal FW flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of FW flow results in an increase in reactor coolant temperature and pressure, which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal FW flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Reference 1 presents an analysis for the Loss of FW (LOFW) Flow event in Section 2.13.2.2.5. The analysis is performed to demonstrate that EFW flow can maintain SG heat removal capability. This is done by showing that SG shell-side inventory is not depleted. Although the licensee classifies the Loss of Normal FW Flow event as an Infrequent Event (i.e., Class III, as defined by ANSI N18.2-1973), the event results also satisfy the Moderate Frequency Event (i.e., Class II) acceptance criteria.

This is one of the events that was reviewed by NRC staff, at the Westinghouse office, in Connecticut. The staff read the documents that detailed the calculation inputs and methods, and, whenever possible, discussed the results and interpretation of results with the engineers who performed the analyses. This event was selected by the NRC staff for a more detailed review because operation at the EPU power level will produce more decay heat, after shutdown, and this event tests EFW decay heat removal capability.

In the LOFW calculation documentation, which supported the power uprate analyses, two cases were evaluated: (1) LOFW for determination of peak pressure, and (2) LOFW for demonstration of long-term heat removal.

The LOFW long-term heat removal case used SG liquid inventory as the "figure-of-merit" for demonstrating adequate heat removal. As such, initial conditions and the selection of limiting single failure were aimed at degrading SG liquid inventory. For example, the limiting single failure was failure of turbine bypass valves to reseat. This failure results in a rapid depletion of SG liquid inventory. However, this case did not demonstrate the capability of the EFW system since (1) no failure in the EFW system was assumed, (2) the stuck-open turbine bypass valve promoted a rapid cool-down of the RCS (thus removing initial and decay heat), and (3) the initial conditions did not challenge TMI II.D criteria (discharge of liquid from PSVs).

Although the analysis results indicate that the SGs do not dry out, the staff does not agree that this, by itself, demonstrates that the EFW system provides adequate decay heat removal capability. The staff requested a long-term analysis of the LOFW Flow event, assuming that the worst active single failure occurs in the EFW system. Adequate decay heat removal would be demonstrated when the pressurizer pressure, level, and RCS temperature begin to drop, as the EFW delivery to the SGs begins to remove more heat than is generated by the decay heat process. Satisfaction of the RCS and SG overpressure acceptance criteria is assured by showing that the pressurizer does not become water-solid at any time during the event. Therefore, the NRC staff requested the licensee to provide a new analysis, according to the above specifications.

The licensee responded, in Reference 21, with a long-term analysis of the LOFW, to verify that there is adequate decay heat removal capability. Adequate decay heat removal capability is inferred when a steam bubble is maintained, in the pressurizer, until the operator can take corrective action, and thereby prevent the aggravation of the event into a more serious accident, which could be caused by the discharge of water through the pressurizer safety valves.

Three case studies were provided, two of which involved an assumed control system failure that starts all the charging pumps and ends all letdown flow. These scenarios are conservative, since they can accelerate the filling of the pressurizer; but they constitute a hybrid event, which combines the loss of heat sink event with the mass addition event. This mass addition transient, combined with a severely degraded primary-to-secondary heat transfer due to LOFW, results in a rapid increase in pressurizer water level, which challenges TMI II.D criteria. The scenario credits Operator Action at 15 minutes post-trip to reduce the mismatch between charging and letdown. This Operator Action is reasonable and consistent with other Chapter 15 accidents. The results of these case analyses indicate that there is enough decay heat removal to provide the operator with enough time to take measures that prevent filling of the pressurizer.

The third case assumed a single active failure in the EFW system, which resulted in the minimum EFW flow (575 gpm) being delivered to the SGs. This is the loss of heat sink event analysis that the staff requested. No operator action is credited, since the purpose of the requested analysis was to verify that the pressurizer does not fill before the operator can take action. The results of the requested, long-term case analysis indicate that the increase in pressurizer pressure and level are limited. EFW is delivered to the SGs, and removes enough decay heat to cool the RCS and prevent filling of the pressurizer.

These cases demonstrate that the EFW system is capable of removing decay heat loads at the EPU conditions and that Waterford 3 continues to satisfy TMI II.D criteria.

Summary

The NRC staff has reviewed the licensee’s analyses of the LOFW flow event and concludes that the licensee’s analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limit will not be exceeded as a result of the LOFW flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of normal FW flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

Regulatory Evaluation

Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either a RCS cooldown (by excessive energy discharge through the break, e.g., if the break flow is mostly steam) or a RCS heatup (by reducing FW flow to the affected RCS). In either case, reactor protection and safety systems are actuated to mitigate the transient. FW system pipe breaks that result in an RCS cooldown resemble steam line ruptures, which are addressed in Section 2.8.5.1.2. Therefore, this evaluation will focus upon the FW system pipe breaks that result in an RCS heatup. The NRC staff's review covered: (1) postulated initial core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) the assumed response of the reactor coolant and auxiliary systems; (5) the functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and GDC 35, insofar as it requires the reactor coolant system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.2.8 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The FWLB event, or rupture of a main FW pipe, can empty an SG, if the break is assumed to occur between the SG and the check valves. Blowdown of the other, unaffected SG is ended by the main steam isolation signal (MSIS) actuation, by closure of the MS and FWIVs. The FWLB event can generate any of the following RPS signals:

- Low SG level
- High pressurizer pressure
- Low SG pressure

Other reactor trip signals that may be generated during the event are the CPCS low DNBR trip and the high containment pressure trip.

A LOOP is assumed to occur during large break FWLB events. Smaller breaks (less than 0.2 square feet (sq ft)) are analyzed assuming a failure to fast bus transfer, resulting in coastdown of two RCPs, as per current licensing basis analyses.

EFW is actuated and delivered to the intact SG upon receiving an EFW actuation signal; some to the ruptured SG and some to the intact SG. After the ruptured SG is isolated, all the EFW flow is routed to the intact SG.

Pressurization of the RCS is limited by the opening of PSVs. Since the FWLB will also generate a SIAS, which starts two charging pumps and isolates letdown, there is an expectation that the pressurizer will eventually fill with water. Operator action is required to turn off the charging pumps in order to prevent the pressurizer from becoming water-solid. The licensee has analyzed a range of break sizes in order to determine how quickly the operator must act to prevent filling of the pressurizer. Thus, the FWLB event is analyzed to determine the maximum RCS pressure and, again, to ascertain the minimum operator reaction time. The effect of the uprating is expected to aggravate both these results.

The FWLB analysis (maximum RCS pressure case) is presented by the licensee to demonstrate that this event does not violate the acceptance criteria for FWLB in the Waterford 3 licensing basis, considering the effects of the EPU. These acceptance criteria are based upon the acceptance criteria for limiting faults. For the smaller break size FWLB events, without assumption of a LOOP, RCS pressure must not exceed 110 percent of design pressure. For the larger break size FWLB events, with LOOP and SAF assumed, RCS pressure must not exceed 120 percent of design pressure.

The analysis results for the FWLB event (maximum RCS pressure case) are:

Break size (sq ft)	Maximum RCS Press (psia)	at time (sec)	Max SG Press (psia)	at time (sec)	Min DNBR
0.12 (Large FWLB)	2753	28.2	1122	35.0	1.64
0.17 (Small FWLB)	2671	40.5	1129	46.1	1.73

The two maximum RCS pressure cases are not directly comparable, since they're based upon different underlying assumptions. For example, the Large FWLB case assumes that a LOOP occurs at the time of reactor trip, whereas the Small FWLB case assumes there is a fast bus transfer failure at the time of turbine trip, causing two of the four RCPs to coastdown. The Large FWLB analysis results in the power uprate request stem from a parametric study of a range of break sizes, using the Large FWLB initial conditions and assumptions (e.g., a LOOP). The result was a case that is based upon a limiting break size of 0.12 sq ft. Similarly, the Small FWLB analysis results in the power uprate request are the product of case studies that used the Small FWLB initial conditions and assumptions (e.g., a failure in the fast bus transfer). The result was a limiting break size of 0.17 sq ft, a break size that turns out to be larger than the limiting break size for the Large FWLB. Neither of these analyses predict filling of the pressurizer within 100 seconds.

Other long-term analyses were performed to verify that the pressurizer does not fill during the FWLB event. Only the conclusions of these analyses are presented in Reference 1. The licensee concludes that the operator has 12 minutes, following the SIAS, to turn off the charging pumps in order to avoid filling the pressurizer. The supporting analyses and calculations (proprietary information) were reviewed by the staff, at Westinghouse's offices, in

Windsor, CT, on August 11 and 12, 2004. The staff used copies of these analyses for further review at the staff's offices. The staff finds the licensee's conclusion that the operator would have at least 12 minutes to turn off the charging pumps after the SI system (SIS) is actuated acceptable. The licensee currently has procedures by which the operators can recognize the condition and act to turn off the charging pumps prior to the filling the pressurizer (e.g., within the 12 minutes) as allowed by these analysis results.

The staff read the documents that detailed the calculation inputs and methods, and, whenever possible, discussed the results, and interpretation of results with the engineers who performed the analyses. This event was selected by the NRC staff for a more detailed review because operation at the EPU power level will produce a greater heat source/sink mismatch when the SG blows dry. This event, like the LOFW accident, also tests EFW decay heat removal capability.

The staff has performed a confirmatory analysis to verify the peak pressure attained during the Large FWLB using the licensee's safety analysis results for this event as boundary conditions.

To evaluate the peak pressure, a solution of the mass, energy, and equation of state applied to the primary system produces the following expression for RCS depressurization rate:

$$\frac{dP_i}{dt} = \left[[h_i \sum_j w_j - (\sum_j w_j h_j + Q_i)] \frac{\partial v}{\partial h}\bigg|_p - v_i \sum_j w_j \right] \Bigg/ \left[M_i \frac{\partial v}{\partial p}\bigg|_h + V_i \frac{144}{778} \frac{\partial v}{\partial h}\bigg|_p \right]$$

for control volumes, I, links by junctions, j, where

h_i	= RCS enthalpy, Btu/lb
w_j	= Net mass flow rate into or out of the system, lbs/s
Q_i	= Net heat load into the RCS, Btu/s
M_i	= RCS total mass, lbs
Vi	= Total primary system volume
v_i	= RCS specific volume, ft^3/lb

(Note - variables are in italic font)

At the time of the peak pressure, the time rate of change in RCS pressure can be set to zero. Thus, the above equation can be simplified to:

$$[h_i \sum w_j - (\sum w_j h_j + Q_i)] \frac{\partial v}{\partial h}\bigg|_p = v_i \sum w_j$$

Knowing the core power, the SG heat removal rate, and the steam flow through the safety valve, the peak RCS pressure that satisfies the above equation can be determined. At about 30 seconds into the event, the following information was extracted from the large FW line break analysis in Reference 1:

Core Power	= 3735 MWt x 0.16 x 948.817Btu/s/MWt
SG Heat Removal	= 4.4 x 10^5 Btu/s [=700 lbs/s x 631.5 Btu/lb (@1100 psia)]
Pressurizer Safety Valve Flow	= 280 lbs/s

Insertion of these values into the equation yields a peak pressure of about 2730 psia, which compares well with the licensee's value (2753 psia).

Using a staff alternate blowdown code/methodology, the peak RCS pressure was calculated to be within 50 psi of the Waterford 3 calculated value of 2753 psia, providing further confirmation of the licensee's conservative analysis methods and results.

Summary

The NRC staff has reviewed the licensee's analyses of FW system pipe breaks and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control elements is maintained, the RCPB pressure limit will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FW system (FWS) pipe breaks.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.3.1-2 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Although Reference 1 classifies the Loss of Forced Reactor Coolant Flow as an Infrequent Event, the specified acceptance criteria are equivalent to those of a Moderate Frequency Event, consistent with the SRP and ANSI N18.2-1973. The principal concern for the Loss of Forced Reactor Coolant Flow is loss of thermal margin and the potential for fuel clad damage. The minimum DNBR is expected to occur early in the transient, when flow begins to decrease and power level is still relatively high.

The flow coastdown is determined using the CENTS computer code (Reference 54). Prior to this power uprate request, flow coastdown was calculated with the COAST code. The licensee has compared the results of both codes and concluded that the differences in calculated flow coastdown rates were minor.

The total loss of reactor coolant flow analysis was performed with Reference 54. The core average and hot channel simulations were produced with HERMITE computer code (Reference 55), and the transient DNBR values were calculated using the CETOP-D computer code (Reference 56), which applies the CE CHF correlation.

The event is assumed to occur at 100.5 percent of EPU power with a LOOP, which causes the turbine to trip, MFW flow to end, and all four RCPs to coast down. The reactor is assumed to trip when the CPCS low RCP shaft speed trip signal is received.

The reactor is tripped within the first two seconds of the event, and the minimum DNBR is reached shortly thereafter. The SAFDL of 1.26 is not violated. Thus, the acceptance criteria for an event of Moderate Frequency are met.

Summary

The NRC staff has reviewed the licensee's analyses of the decrease in reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of an RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial and long-term core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed reactions of reactor system components, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; and GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

RCP Rotor Seizure and RCP Shaft Break are events that can occur due to a mechanical failure of an RCP shaft (i.e., rotor). This is assumed to result in either a seizure or the shearing of the RCP shaft. As a result, core flow rate rapidly decreases to about the level that would correspond to operation of three RCPs. The reduction in coolant flow rate degrades core heat transfer and causes a heatup in the core. This could lead to DNB and fuel clad damage.

The RCP shaft seizure and sheared shaft events are classified as limiting fault events, which is consistent with ANSI N18.2-1973 and Waterford 3's licensing basis. The licensee has analyzed both events, and determined that, with the proposed EPU, the limiting event continues to be the RCP sheared shaft with a LOOP. For an RCP shaft seizure event, a reactor trip signal on low RCP shaft speed is generated via the CPCS. This signal is not generated during an RCP sheared shaft event, since the CPCS reads the spinning RCP shaft as evidence that full flow must be present. For the RCP sheared shaft event, reactor trip signal is generated from the reduction in the pressure difference across the affected loop SG, due to the decrease in reactor coolant flow.

The LOOP occurs following the automatic turbine trip, due to an assumed failure to transfer the RCP busses to offsite power. The LOOP causes the remaining three RCPs to coast down, and the reduced reactor coolant flow depletes the core thermal margin. The minimum DNBR is reached as a result of the rapid reduction in core power caused by the reactor trip.

For limiting faults, some fuel rod cladding perforation is acceptable, but no other barriers may be breached. Offsite radiological consequences must be less than 10 percent of 10 CFR Part 100 guidelines (i.e., 30 rem thyroid, 2.5 rem whole body).

The reactor coolant flow coastdown was calculated with Reference 54. The core average and hot channel simulations were produced with Reference 55, and the transient DNBR values were calculated using Reference 56, which applies the CE CHF correlation.

The minimum DNBR, 1.0698, occurs at 3.25 seconds, or 2.15 seconds after the CEAs begin to drop into the core. The licensee's methodology points to calculations that predict less than 15 percent of the fuel rods will fail. This is the extent of fuel failure that can be incurred without violating the offsite dose limits. The reduction in flow and heat transfer also causes reactor pressure to increase, but the pressure does not rise to the level needed to open the PSVs.

Summary

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control elements is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, and 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Element Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control element assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the transient and the transient itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

Uncontrolled CEA Withdrawal from a Subcritical Condition, and Uncontrolled CEA Withdrawal from a Low Power Startup Condition are both events of Moderate Frequency. The acceptance criteria for events of Moderate Frequency do not permit any fuel damage (i.e., the minimum DNBR must be greater than the SAFDL of 1.26).

The Uncontrolled CEA Withdrawal from a Subcritical event does not occur at full power, so the EPU should not have a direct effect upon the transient. However, the setpoint for the automatic reactor trip that is credited for this event, the high logarithmic power level trip, is based upon the rated power. Since the EPU has the effect of changing the setpoint of the credited reactor trip, the licensee has submitted a new analysis. This analysis also documents the licensee’s shift from CESEC to Reference 54 to simulate the Uncontrolled CEA Withdrawal from a Subcritical event. The licensee has noted that there were no significant differences seen between the results of analyses performed with the two codes.

The results of the Uncontrolled CEA Withdrawal from a Subcritical event indicate that the SAFDL continues to be satisfied.

The Uncontrolled CEA Withdrawal from a Low Power Startup Condition has also been analyzed using Reference 54. The results of this analysis also indicate that the SAFDL continues to be satisfied.

Summary

The NRC staff has reviewed the licensee’s analyses of the Uncontrolled CEA Withdrawal from a Subcritical or Low Power Startup Condition and concludes that the licensee’s analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee’s analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the Uncontrolled CEA Withdrawal from a Subcritical or Low Power Startup Condition.

2.8.5.4.2 Uncontrolled Control Element Assembly Withdrawal at Power

Regulatory Evaluation

An Uncontrolled CEA Withdrawal at Power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the associated analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 20, insofar as it requires that the RPS system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The Uncontrolled CEA Withdrawal at Power event is an event of Moderate Frequency, that is analyzed using Reference 54. Since this event is assumed to occur at hot full power (HFP) conditions, the EPU will directly affect the initial conditions of the analysis.

The analysis is based upon the assumption of the most positive/least negative moderator temperature coefficient (MTC) (0) D//F at HFP), and addresses a range of CEA bank worths from the maximum worth (the case presented in the Reference 1), to lower CEA bank worths, which elicit responses from the automatic RPS system at later times, with different trip logic schemes. The maximum reactivity insertion rate that is analyzed is 0.55×10^{-4}) D/sec.

For the limiting HFP CEA bank withdrawal event, the peak core power results in a peak LHR of less than 21 kW/ft, a minimum DNBR of 1.44 at 12.4 seconds, and a maximum RCS pressure of 2287 psia at 14.8 seconds. The acceptance criteria for this event are satisfied.

Summary

The NRC staff has reviewed the licensee's analyses of the Uncontrolled CEA Withdrawal at Power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the Uncontrolled CEA Withdrawal at Power.

2.8.5.4.3 Control Element Misoperation

Regulatory Evaluation

The NRC staff's review covered the types of control element misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered (1) descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) which can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses; (4) important inputs to the calculations; and (5) the results of the analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs, and to initiate automatically operation of systems and components important to safety under accident conditions; and GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.3 and other guidance provided in Matrix 8 of Reference 31.

<u>Technical Evaluation</u>

The limiting control element misoperation event is the CEA drop. A single full-length CEA drop results from an interruption in the electrical power to the CEDM holding coil of a single full length CEA. This interruption can be caused by a holding coil failure or loss of power to the holding coil. The limiting case is the single CEA drop, which does not cause a trip to occur, but results in an approach to the DNBR SAFDL. Approach to the SAFDLs are greater for the single CEA drop than for the dropping of a CEA subgroup (a set of four symmetrical CEAs moved by the same CEDM control system), since the dropped CEA subgroup causes a symmetric perturbation, which produces a less pronounced power distribution distortion.

The abnormal core power distribution causes the automatic application of relatively high power distribution penalty factors in the CPCs, which can generate a reactor trip on low DNBR or high-power density.

The event is defined as the release and drop of a full-length CEA, which causes a rapid decrease in power. The mismatch between the secondary side (initial turbine demand) and primary side (post-drop power less than initial demand) results in reduced reactor coolant temperatures and pressure. In the presence of a negative MTC, positive reactivity is added, which tends to restore the primary power to the initial power level. Thus, the core returns to initial power with a high hot pin radial peaking factor, which can result in a DNBR that violates the DNBR SAFDL.

The licensee indicates that specific values for radial distortion factors, associated with dropped CEAs and CEA subgroups, will be determined as part of the reload design process, to meet the SAFDL requirements. The effect of any misoperated CEA on core power distribution assessed by the CEA calculators (CEACs) and an appropriately augmented power distribution penalty factor is supplied as input to the CPCs. As the reactor core responds to the reactivity changes caused by the misoperated CEA and the ensuing moderator and Doppler feedback effects, the CPCs will initiate a low DNBR or high local power density trip if SAFDLs are approached.

Sufficient initial thermal margin is preserved by the limiting conditions for operation so that the plant may experience a CEA drop without requiring a reactor trip to ensure that the SAFDLs are not violated.

The system response during the CEA Drop scenario is calculated with Reference 54. At HFP, a single CEA is assumed to drop into the core within one second. The reactivity of this CEA is assumed to be greater than or equal to the reactivity of the most reactive CEA. The core power drops and then returns to full power with a reduced core inlet temperature and a distortion of radial power distribution.

The plant limiting conditions for operation (LCOs) provide for the thermal margin necessary to account for the static radial distortion and 15 minutes of xenon redistribution. During this time, the operators act to restore the CEA alignments. If recovery cannot be made within this time period, the operators are directed to meet time-dependent power reduction requirements to provide the thermal margin necessary to compensate for continued xenon redistribution.

The analysis results indicate that core power at the time of minimum DNBR is 100.6 percent at 900 sec. Minimum DNBR is greater than 1.26, and peak LHR is less than 21 kW/ft. Therefore, the acceptance criteria, in this example, are satisfied. The licensee indicates that the acceptance criteria will continue to be met, as specific radial distortion factors will be applied in reload design analyses of the uprated core.

Summary

The NRC staff has reviewed the licensee's analyses of control element misoperation events and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipated operational transients. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to control element misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. The NRC staff's review covered (1) the sequence of events, (2) the analytical model, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; GDC 20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; and GDC-26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The inadvertent startup of an inactive RCS pump is an event of Moderate Frequency.

If there is a significant temperature difference between the primary and secondary cooling systems, then the startup of a RCP could cause a rapid change in core moderator temperature, and a consequent reactivity excursion.

This event is considered in Modes 4 and 5, since the TSs permit RCPs to be idle below Mode 3. The analysis results, presented in the UFSAR, indicate that the available shutdown margin would prevent criticality due to an inadvertent reactor coolant system pump startup. Therefore, the Condition II acceptance criteria are met.

Unless the shutdown margin, in Modes 4 and 5, is reduced, the EPU would have no effect upon the UFSAR analyses. Reference 1 does not discuss the inadvertent startup of an inactive reactor coolant system pump, other than to indicate that the UFSAR analyses address this event under the EPU conditions. The staff agrees with this approach.

Summary

The NRC staff has reviewed the licensee's analyses of the inactive loop startup event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the increase in core flow event.

2.8.5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

Regulatory Evaluation

Unborated water can be added to the RCS, via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated. The NRC staff's review covered (1) conditions at the time of the unplanned dilution, (2) causes, (3) initiating events, (4) the sequence of events, (5) the analytical model used for analyses, (6) the values of parameters used in the analytical model, and (7) results of the analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.6 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The CVCS malfunction that results in a decrease in boron concentration in the reactor coolant is not affected by the EPU. For boron dilution during refueling, during cold shutdown with the RCS filled, and during cold shutdown with the RCS partially drained, the available operator response time meets the requirements. A change in RTP has no effect upon this event. The evaluation contained in UFSAR 15.4.1.5 remains valid, under EPU conditions.

Summary

The NRC staff has reviewed the licensee’s analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the licensee’s analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.6 Spectrum of Rod Ejection Accidents

Regulatory Evaluation

Control element ejection accidents cause a rapid positive reactivity insertion, together with an adverse core power distribution, which could lead to localized fuel rod damage. The NRC staff evaluates the consequences of a control element ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff’s review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC’s acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to impair significantly the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.8 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

A CEA is assumed to be ejected as the result of a complete circumferential break of either the CEDM housing or its nozzle section on the reactor vessel head. The CEA ejection inserts positive reactivity into the core, which causes local powers and fuel temperatures to rise. The Doppler fuel temperature coefficient, given the increasing fuel temperature, inserts negative reactivity into the core, which tends to mitigate the rapid power rise due to the ejected CEA. Reactor trip occurs on variable overpower.

The acceptance criteria for the CEA ejection event are:

10. The radially averaged fuel enthalpy must be not be greater than 280 calories per gram (cal/gm). The incipient fuel melting enthalpy limit is 250 cal/gm.
11. The peak RCS pressure must be not be greater than 2750 psia.
12. Radiological consequences must be within 10 CFR Part 100 limits.

Two forms of CEA ejection analyses are performed: one to calculate the extent of fuel damage to be expected (and the dose consequences), and the other to calculate the maximum RCS pressure. Specifically, the former analyses are designed to ascertain (1) the number of fuel pins at which the DNBR SAFDL (1.26) would be violated, and (2) the number of fuel pins that would experience enthalpies of 250 and 280 cal/gm, assuming initial power levels of 20 percent, 50 percent, 80 percent, and 100 percent of RTP. These analyses are performed using the STRIKIN II computer code (Reference 57). The number of fuel pin failures is calculated from the DNBR data. The latter analysis is performed, using Reference 54, to calculate the peak RCS pressure, assuming that there is no relief through the CEA ejection location.

The ejected CEA worths that are assumed for the EPU core are slightly greater than the values assumed in the current analyses. The values assumed in the power uprate analyses would be greater than those expected for actual uprate cycles, and are, therefore, conservative..

The licensee's analysis results indicate that the acceptance criteria are satisfied. The total average enthalpy of hottest fuel pellet is 156 cal/gm, and the total centerline enthalpy of hottest fuel pellet is slightly less than 250 cal/gm. There are no rods predicted to experience incipient centerline melting (centerline enthalpy $ 250 cal/gm), or have a radially averaged enthalpy of at least 280 cal/gm. For the peak RCS pressure case, the RCS pressure is calculated to remain within the 2750 psia limit (2613 psia attained at 2.9 seconds) as stated in Reference 15.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993 and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident (RIA), such as a CEA Ejection event, at lower enthalpies than the limits currently specified in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel that has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/g.

The staff has concluded that, although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated RIAs in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium, such as Waterford 3, will neither (1) result in damage to the RCPB, nor (2) sufficiently disturb the core, its support structures, or other RPV internals to impair significantly the capability to cool the core as specified in current regulatory requirements.

The licensee has determined that the 10 CFR Part 100 limits would not be exceeded unless more than 15 percent of the fuel pins fail due to DNB. Thus, adherence to the 15 percent fuel failure limit would ensure that 10 CFR Part 100 limits are met (according to the methodology described in Section 2.13.0.5 of Reference 1). The licensee states that cycle-specific fuel failure evaluations for EPU cores will be performed to ensure that this fuel failure limit will not be exceeded.

Summary

The NRC staff has reviewed the licensee's analyses of the rod ejection accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.4.7 Inadvertent Loading of a Fuel Assembly Into an Improper Position

Regulatory Evaluation

The inadvertent loading of a fuel assembly into an improper position could affect core power distribution, and possibly impair core performance. Although there are many configurations of misloaded fuel, the most serious situation would arise from interchanging two assemblies of different enrichments. Some misloadings would be detected during the low power physics testing. Other misloadings might not be detectable.

NRC staff evaluates the consequences of the inadvertent loading of a fuel assembly into an improper position to determine whether the distorted core power distribution would lead to fuel damage and, if so, whether the resultant offsite doses meet the appropriate acceptance limits. The NRC's acceptance criteria are based upon GDC 13, since it pertains to instrumentation and controls provided to monitor variables over anticipated ranges for normal operations, AOOs, and accident conditions, and upon 10 CFR Part 100 for offsite consequences resulting from reactor operations with an undetected misloaded fuel assembly. Specific review criteria are contained in SRP Section 15.4.7.

Technical Evaluation

The principal means of preventing fuel loading errors are operating procedures and plant design features. If operating procedures and plant design features fail to prevent a fuel loading error, then core instrumentation systems would detect it. If an error is made and goes undetected, then it could lead to the violation of fuel rod failure limits. Therefore, the event is evaluated against two acceptance criteria:

1. To meet the requirements of GDC 13, plant operating procedures should include a provision requiring that reactor instrumentation be used to search for potential fuel-loading errors after fueling operations. Fuel-loading errors could adversely affect the fission process (power distribution), the integrity of the reactor core, and the RCPB. Meeting the requirements of GDC 13 provides assurance that fuel-loading errors will be detected before they can affect power distribution or core integrity, or could produce unacceptable stress on the RCPB.

2. In the event the error is not detectable by the instrumentation system and fuel rod failure limits could be exceeded during normal operation, the offsite dose consequences should be less than 10 percent of the 10 CFR Part 100 guidelines. The methodology for calculating radiation exposures at the site boundary for events that might be caused by a fuel-loading error is specified in 10 CFR Part 100. For events having a moderate-frequency of occurrence, any release of radioactive material must be such that the calculated doses at the site boundary are a small fraction of the 10 CFR Part 100 guidelines. A small fraction is deemed to be less than 10 percent of the 10 CFR Part 100 reference values. For the purpose of this review, the radiological consequences of any fuel-loading error must include consideration of the containment, confinement, and filtering systems. The licensee's source terms and methodologies, with respect to gap release fractions, iodine chemical form, and fission product release timing, should reflect NRC-approved source terms and methodologies.

The licensee has noted three startup test criteria that can be used to detect fuel misloads:

1. The power in each operable symmetric detector shall be within ±10.0 percent of the average power in its symmetric detector group
2. The vector tilt shall be less than 3 percent (for power levels greater than 20 percent)
3. The measured value for the radial peak including tilt shall be within ±10 percent of the predicted value

Thus, the error is detectable via the available instrumentation (and therefore can be corrected), or the error is not detectable, in which case the offsite dose consequences of any fuel rod failures would be a small fraction of 10 CFR Part 100 guidelines.

The power uprate presents analyses to show that, if all the incore detectors in the vicinity of the misloaded assembly are operational, then the fuel misload will be detected during power ascension physics testing, since it would meet the first test criterion (i.e., the maximum power difference between a detector and the average of its symmetric detector group would be greater than 10 percent).

If 3 out of the 4 incore instruments (ICIs) in the vicinity of the misload are inoperable, then the misload might not be detected and the core might be operated with the fuel misload. The applicant has determined that there is enough overpower margin (18 percent) to cover the error in measured power peaking due to the misload (15 percent), assuming that 3 out of the 4 ICIs in the vicinity of the misload are inoperable. The licensee also states that the overpower margin is typically 20 per cent, a value that is confirmed to exceed the required overpower margin as part of the core reload process. Therefore, there would be enough thermal margin so that the DNB SAFDL would not be violated and no fuel damage would be expected. The minimum DNBR at nominal core conditions for the representative worst case undetectable misload is greater than 2.0.

These results indicate that there is sufficient overpower margin for the representative worst case undetectable misload to accommodate a reasonable combination of off-nominal core operating conditions and/or expected operational occurrences without resulting in doses that exceed a small fraction of 10 CFR Part 100.

The staff concludes that the licensee has met the requirements of GDC 13 by providing adequate provisions to minimize the potential of failing to detect a misloaded fuel assembly. The requirements of 10 CFR Part 100 are also met, since the consequences of reactor operations with a misloaded fuel assembly would not include any fuel failures.

Summary

The NRC staff has reviewed the licensee's analyses of the inadvertent loading of a fuel assembly into an improper position, and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff's conclusion is based upon the licensee's demonstration that there is appropriate overpower margin to permit operation with an undetected fuel misload, without causing any fuel damage. The NRC staff concludes that the plant will continue to meet the requirements of GDC 13 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent loading of a fuel assembly into an improper position.

2.8.5.5 Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the

RCPB are not exceeded during AOOs; and GDC 26, insofar as it requires that a reactivity control system be provided and be capable of reliably controlling the rate of reactivity changes to ensure that, under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

An inadvertent increase in reactor coolant inventory, due to equipment failure or operator error, can be defined as the starting of one or more charging pumps and the concurrent reduction of letdown flow. This event is assumed to insert water of the same boron concentration as the boron concentration of the RCS. Therefore, there would be no reactivity perturbations. Discussion of the CVCS malfunction that causes a boron dilution is discussed in Section 2.8.5.4.5 of this SE.

This event may be characterized as a mass addition to the RCS, which has the potential of filling the pressurizer, and ultimately discharging water through the PSVS. According to the AOR, in UFSAR 15.5.1.1, the pressurizer will not fill before the operator terminates the event or the reactor is tripped on high-pressurizer pressure. Raising the RTP, with no significant change in RCS temperatures, would not change this conclusion. Therefore, the staff finds that the AOR remains valid for operation at the EPU conditions.

Summary

The NRC staff has reviewed the licensee's analyses of the inadvertent operation of ECCS and CVCS event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS and CVCS event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Safety Valve

Regulatory Evaluation

The inadvertent opening of a PSV results in a reactor coolant inventory decrease and a decrease in RCS pressure. A reactor trip normally occurs due to low RCS pressure. Since Waterford 3 is not equipped with power-operated pressurizer relief valves, this evaluation is limited to PSVs. PSVs open as pressurizer pressure exceeds their opening setpoint, or possibly as the result of a mechanical failure. The opening of a PSV that subsequently fails to reseat properly may be considered as a SBLOCA at the top of the pressurizer. Therefore, the NRC staff reviewed this event in terms of the acceptance criteria of the SBLOCA, identified in Section 2.8.5.6.3 of this SE. Specific review criteria are also contained in SRP Sections 6.3 and 15.6.5, and other guidance is provided in Matrix 8 of Reference 31.

Technical Evaluation

Waterford 3 is equipped with spring-loaded PSVs, not power-operated pressurizer relief valves. The spurious opening of a PSV must be due solely to a mechanical failure, not an operator error or electrical fault. Therefore, its frequency of occurrence would be very low, permitting the event to be classified as a Limiting Fault.

This event could be considered as a small break in the steam space of the pressurizer, the consequences of which would be bounded by the SBLOCA (discussed in Section 2.8.5.6.3) of this SE.

Summary

The NRC staff concludes that the opening of a PSV, with failure to reseat properly, is not an AOO. This event is treated by the licensee as a SBLOCA at the top of the pressurizer. The staff finds this approach acceptable. Please see Section 2.8.5.6.3 of this SE for a discussion and evaluation of the SBLOCA.

2.8.5.6.2 Steam Generator Tube Rupture

Regulatory Evaluation

A SG tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and MS safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR Part 100. The NRC staff's review covered (1) postulated initial core and plant conditions, (2) method of thermal and hydraulic analysis, (3) the sequence of events (assuming offsite power either available or unavailable), (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions consistent with the plant's EOPs, and (7) the results of the accident analysis. A single failure of a mitigating system is assumed for this event. The NRC staff's review of the SGTR is focused on the thermal and hydraulic analysis for the SGTR in order to (1) determine whether 10 CFR Part 100 is satisfied with respect to radiological consequences, which are discussed in Section 2.9 of this SE and (2) confirm that the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent the failure of main steam lines. Specific review criteria are contained in SRP Section 15.6.3 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

An SGTR event causes direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose within the guidelines of 10 CFR Part 100 limits. The staff's review covers postulated initial core and plant conditions, method of thermal and hydraulic analysis, sequence of events assuming with and without offsite power available, assumed reactions of reactor system components, functional and operational characteristics of the RPS, required operator actions consistent with the plant EOPs, and the results of the accident analysis. A single failure of mitigating system is assumed for this event. The staff review for SGTR discussed in this section is focused on the thermal and hydraulic analysis for the SGTR in order to: 1) support the review for radiological consequences, which is addressed in another section of this SE, and 2) confirm that there is no overfill of the SG during the mitigation of this event which could cause unacceptable radiological consequences or potential failure of the main steam system. Specific review criteria are contained in SRP Section 15.6.3.

The licensee's SGTR thermal-hydraulic analysis was performed using CENTS Code, which replaces the CESEC Code, of the existing analysis. The NSSS design parameters for the uprated core power of 3716 MWt are used in this analysis. The plant EOPs are considered in the operator actions for accident mitigation of an SGTR. Following an SGTR, a LOOP is assumed to occur at 3 seconds after a reactor and turbine trip. The assumed LOOP leads to a loss of condenser and resulting in the release of steam to the atmosphere via the SG ADVs and/or SVs. The 3-second time delay, an assumed value for the occurrence of the LOOP after a reactor and turbine trip, will affect the calculation of the radiological consequences and DNBR. The acceptability of the assumed LOOP delay time is reviewed by the staff and the evaluation is addressed in the Section 2.3 of this SE. The evaluation of the radiological consequences is addressed in the Section 2.9 of this SE.

There is one ADV for each of the two SGs at Waterford 3. In Reference 1, the licensee assumed that the majority of the cooldown of the plant is performed by steaming from the unaffected SG. The licensee later realized that this assumption is not consistent with the EOPs, which specify the use of both ADVs for plant cooldown. The licensee, in Reference 21, submitted a re-analysis of the SGTR event, assuming the use of both ADVs during plant cooldown. The staff finds that this assumption results in a more limiting radiological consequence. The results of the new analysis confirm that the peak primary and secondary system pressures remain below their respective acceptance criteria, and that DNBR remains above the DNB SAFDL. These transient data are used in the assessment of radiological consequences.

With respect to the potential for SG overfill, the licensee stated that the operators will terminate EFW to the affected SG upon identifying it as the affected SG (Reference 12). Additionally, the operators are instructed to control level in the affected SG to ensure that level does not exceed 85 percent narrow range (94 percent wide range). The operators will also increase back flow from the secondary to the primary via pressure control actions on the primary system. These instructions in plant procedures will ensure that the affected SG will not overfill. This control approach is also consistent with the current licensing basis of the plant. We find this approach acceptable.

Summary

The NRC staff has reviewed the licensee's analysis of the SGTR accident and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods and approved computer codes. The NRC staff further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the faulted SG. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SGTR event.

The licensee assumed a 3-second time delay for a LOOP following a plant trip in its SGTR analysis. The acceptability of this assumed time delay has been reviewed and addressed in Section 2.3 of this SE.

2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long term cooling (LTC); (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on (1) 10 CFR § 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of Reference 31.

Technical Evaluation

The staff reviewed the ECCS performance to confirm that the system design provides an acceptable margin of safety following a LOCA and has been accomplished using acceptable analytical methods. Acceptance criteria are based on the provisions of 10 CFR 50.46.

The adequacy of the safety injection system (SIS) during the injection and sump recirculation phases following a LOCA was verified in the LOCA analyses performed at a core power level of 3716 MWt with acceptable results. For the non-LOCA events, the performance of SIS is also verified by various safety analyses performed in support of the proposed EPU. The licensee concluded that no system modifications are required to support the proposed EPU. The staff has reviewed the licensee's assessment and finds the results acceptable based of the safety analyses addressed below.

The licensee provided LOCA analyses results for Waterford 3 operating at 3735 MWt (3716 MWt plus 0.5 percent measurement uncertainty) in Reference 75 (LBLOCA), and Reference 10 (SBLOCA). The staff reviewed the analyses to assure that Waterford 3, operating at the uprated power of 3716 MWt, would satisfy the ECCS criteria of 10 CFR 50.46(b). The licensee performed these LOCA analyses using W/CE-approved LBLOCA and SBLOCA methodologies described References 61 and 60, respectively.

In Reference 12, the licensee provided information to justify the application of the S2M SBLOCA methodology (Reference 60) to Waterford 3 operating at the uprated power of 3735 MWt (analyzed at 1.005 times rated power of 3716 MWt). This information included a repeat of the sensitivity study, originally included in CENPD-137 Supplement 2-P, Appendix E for CE designs operating at up to 3410 MWt, but this time assuming Waterford 3 operating at 3735 MWt. The results of this study did not indicate as much conservatism as the S2M study, but confirmed sufficient retained conservatism to compensate for postulated analysis non-conservatisms. The licensee’s implementation of ongoing processes to assure appropriate input to the analyses (following paragraph) further substantiates the applicability of the S2M methodology to Waterford 3. The staff concludes that the SBLOCA methodology described in CENPD-137 Supplement 2-P is applicable and acceptable for performing licensing basis SBLOCA analyses of Waterford 3 operating at analyzed powers up to 3735 MWt. At this time, this finding of applicability is for Waterford 3 at the stated powers (because of the Waterford 3 plant specific design) and applies to no other plant at that power. While the methodology applies to Waterford 3, each unit must provide its plant-specific analysis results or justify the applicability of these or similar existing analyses to satisfy 10 CFR 50.46.

In Reference 12, the licensee provided a statement that “1) Waterford 3 operating at the extended power uprate is bounded by the assumptions used in the analyses that support the approval of the S2M evaluation model as shown in [the above paragraph]; and, 2) Waterford 3 and its vendor, Westinghouse Electric Company LLC, continue to have ongoing processes, which assure that LOCA analysis input values bound the as-operated plant values for those parameters.” This statement assures that the licensee properly applies the model in using the LOCA methodologies as discussed in the preceding paragraphs, such that the reported results specifically represent the Waterford 3 ECCS performance within the applicability range(s) of the methodology(ies) (i.e., that the methodologies specifically apply to Waterford 3 per 10 CFR 50.46(c)(2)).

In Reference 75, the licensee provided results for the Waterford 3 analyses it performed at the uprated power using the CENPD-132, Supplement 4-P-A (Reference 61) LBLOCA methodology.

The calculated PCTs, the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation using the model are given in the following table. The following table provides results of analyses using the LBLOCA analysis methodology in Reference 61 at the uprated power for LBLOCA PCT.

Model	CEN-132-S4
Limiting Break Size Location	0.8 ft^2 Double-ended guillotine/Pump discharge
Cladding	Zircaloy
PCT	2153 ^oF
Maximum Local Oxidation	8.5 percent
Maximum Total Core-Wide Oxidation (All Fuel)	<0.99 percent
Peak Linear Heat Generation Rate	12.9 kW/ft

In Reference 10, the licensee provided results of analyses it performed for Waterford 3 SBLOCA analyses power using CENPD-137, Supplement 2-P-A (S2M) SBLOCA methodology.

The table, below, provides results of the analysis with the S2M methodology for SBLOCAs at the uprated power.

Model	S2M *(Zircaloy)*
Limiting Break Size	0.055ft^2 Pump discharge
PCT	2018 ^oF
Max. Local Oxidation	13.1 percent
Max. Total Core-Wide Oxidation (All Fuel)	<0.99 percent

At the staff's request, in Reference 12, the licensee provided information enabling the staff to conclude that the value of the calculated pre-transient oxidation for the zircaloy fuel through the final cycle is sufficiently small that the sum of the pre-transient and post-LOCA oxidation for the zircaloy fuel is less than the 17 percent local oxidation criterion of 10 CFR 50.46(b)(2). Only the results of the calculations identified in the tables above are reported versus the 10 CFR 50.46 criteria, since the discussion of this paragraph also concludes that the 10 CFR 50.46 criteria are met.

With regard to the 1 percent core-wide hydrogen criterion of 10 CFR 50.46(b)(3), the staff notes that the pre-existing oxidation of the Westinghouse fuel would not contribute to the LOCA maximum core-wide hydrogen generation.

As discussed above, the licensee has performed LBLOCA and SBLOCA analyses for Waterford 3 at an uprated power of 3716 MWt using approved Westinghouse methodologies. The licensee's LBLOCA and SBLOCA calculations demonstrated the following:

1. The calculated LBLOCA and SBLOCA values for PCT (2153 ^oF and 2018 ^oF, respectively), oxidation (8.5 percent and 13.1 percent, respectively), and core-wide

hydrogen generation (<0.99 percent and <0.99 percent, respectively) are less than the limits of 2200 °F, 17 percent, and 1.0 percent specified in 10 CFR 50.46(b)(1-3), respectively.

2. Compliance with 10 CFR 50.46(b)(1-3) assures that the core will remain amenable to cooling, as required by 10 CFR 50.46(b)(4).

The staff concludes that the licensee's LOCA analyses are acceptable and demonstrate that the Waterford 3 plant complies with the requirements of 10 CFR 50.46 (b)(1-4).

The regulatory requirement for LTC is provided in 10 CFR 50.46(b)(5), which states "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Although the SRP NUREG-0800 provides some guidance, it essentially repeats the regulatory requirement. In practice, following successful calculated blowdown, refill, and reflood after initiation of larger LOCAs, and following the transient conditions that occur after initiation of smaller LOCAs, the LTC requirement will be met if the fuel cladding remains in contact with water so that the fuel cladding temperature remains essentially at or below the saturation temperature. A potential challenge to LTC is that boric acid (H_3BO_3) could accumulate within the reactor vessel, precipitate, and block the injection water needed for core cooling. Consequently, the staff performed audit calculations of the licensee's approach to control H_3BO_3 during LTC. The staff evaluation and resolution for post-LOCA boron precipitation is described below.

Evaluation of the Mixing Volume Assumptions in the Westinghouse Long Term Cooling Analysis of Waterford 3 at the Extended Power Uprate

The staff has identified several areas of concern through its ongoing review of boric acid precipitation and the methodologies employed to identify the timing for switch to simultaneous hot and cold leg injection. The staff has previously determined that while specific concerns with the models and assumptions exist, the models and methodologies as a whole represent an overall conservative evaluation. Recently, during the review of the Waterford 3 EPU, a potentially non-conservative input was discovered in the Westinghouse model employed to compute the boric acid concentration following a LOCA. This condition was uncovered as a result of the staff calculations to audit post-LOCA LTC performance and the attempts to reproduce the boric acid precipitation time for Waterford 3 at the EPU conditions. Specifically, the input did not account for the voids present in the core and upper plenum following a LOCA. Failure to account for the void fraction in the core and upper plenum mixing volume may produce an incorrect time to precipitation, since an unrealistically high volume of liquid may be present in the mixing volume that could artificially lower the boric acid concentration during the LOCA. The mixing volume is used as a key input to the CENPD-254 methodology of "CENPD-254 Revision 0 and Revision 1, Post-LOCA Long Term Cooling Evaluation Model, June 1977," to compute the time to precipitation following a LOCA.

The input was corrected and an updated licensing analysis was performed. The updated analysis utilized the previously approved post-LOCA LTC methodology described in the above referenced CENPD-254, with the following additional changes:

(1) The mixing volume for computing the boric acid concentration was changed to include the additional volume in the core outlet plenum located between the bottom and top elevations of the hot leg piping at the exit to the vessel. The previously approved model consisted only of that portion of the upper plenum below the bottom elevation of the hot leg piping. The core was also included in the mixing volume, as was previously approved by the staff regarding the use of the CENPD-254 methodology.

(2) The liquid volume in the core and upper plenum mixing volumes (based on the void fraction) identified in item (1) above was calculated by applying the CEFLASH-4AS phase separation model to this region. The phase separation model used in CEFLASH-4AS was previously approved by the staff for computing the mixture level in the core following all SBLOCAs. This model was shown to accurately predict the void fraction and, hence, two-phase level in regions experiencing high rates of heat addition following SBLOCAs.

(3) The mixing volume was increased to also include 50% of the lower plenum. The Mitsubishi Heavy Industries' BACCHUS test facility employed to simulate post-LOCA boric acid mixing in the lower plenum and core of a Westinghouse and CE-designed PWR was cited as justification for expanding the mixing volume to also include a portion of the lower plenum. The tests, summarized in Reference 71, showed that the entire lower plenum volume contributed to the mixing. Hence, crediting only 50 percent of this volume is conservative.

(4) The solubility limit of 27.6 wt% (based on an upper plenum pressure of 14.7 psia at 212 °F) was increased to 36 wt% based on the ternary solution of water, boric acid, and trisodium phosphate present in the mixing volume undergoing boiling at saturation under atmospheric conditions. The Waterford 3 containment contains trisodium phosphate to control sump pH following a LOCA. Switchover from the injection to the recirculation phase following a LBLOCA would be expected to occur between one and two hours post-LOCA.

(5) The BAMT inventory, which is injected via the charging pumps, is mixed with the HPSI water taking suction from the RWST during the injection phase of the LOCA. The BAMT concentration is 6187 ppm compared to the RWST concentration of 3000 ppm. The previously-approved model assumed that the BAMT concentration was injected directly into the core without mixing in the cold legs, downcomer, and lower plenum.

The updated post-LOCA LTC analysis presented in Reference 72, employing the methodology of CENPD-254 with the above changes, produced a precipitation time of 7.2 hours after initiation of the LOCA.

The analysis demonstrates that the three-hour switch time to simultaneous injection to control boric acid is performed prior to precipitation where the margin to precipitation was determined to be approximately 15 wt%. This switch time is also shown to be after hot leg entrainment of the injection is predicted to occur and at the earliest time that half of the injection, at the switch to simultaneous injection, would also exceed the total core boil-off rate to assure the core remains covered with a two-phase mixture.

It is important to note that these updated analyses also retain a level of conservatism and include:

(1) Entrainment of liquid from the core during the initial injection phase was neglected. The entrainment removes large amounts of liquid for the first 15 to 30 minutes following reflood, which minimizes the boric acid build-up during this period.

(2) The minimum containment pressure at three hours is 20 psia; however, atmospheric pressure is assumed following the LOCA. Even with a containment pressure of 14.7 psia, the loop pressure drop varies from about 7.5 psi to about 3 psi during the first three hours following the LOCA, which would increase the solubility limit beyond that at the assumed 14.7 psia upper plenum pressure.

(3) The 1971 ANS decay heat standard was employed, which represents a conservative treatment of decay heat following shutdown of the reactor.

(4) The steam exiting the core is not assumed to contain any boric acid.

The staff calculations are consistent with the vendor's new result with the input corrected and the above additional changes incorporated into the CENPD-254 re-analysis. Based on the staff audit calculations and its review of the new analysis presented in Reference 72 with the above enumerated changes, the staff finds the re-analysis of the post-LOCA LTC performance to be acceptable for Waterford 3 at the EPU conditions.

The acceptability of the input changes enumerated in the Reference 72 analysis, in concert with the use of the CENPD-254 methodology, apply only to Waterford 3 at the EPU conditions. This acceptance does not constitute approval of this approach to other CE-designed NSSSs for which the CENPD-254 methodology was previously approved. Furthermore, acceptance of the analyses for Waterford 3 does not constitute complete acceptance of the boric acid tests and data documented in the BACCHUS test report referenced above. The staff is continuing to review the test information and data contained in the BACCHUS test report.

Boric Acid Precipitation for Small Breaks

The licensee predicted that the core would remain covered by a two-phase fluid in the long term, regardless of break size. It stated that at 12 hours, for breaks as large as 0.036 ft^2, the RCS would be refilled, natural circulation would disperse H_3BO_3 throughout the RCS, and SDC could be used for LTC. Similarly, at 12 hours, for breaks as small as 0.012 ft^2, H_3BO_3 would be flushed from the core and decay heat would be removed via simultaneous hot and cold leg injection. These values indicate that there is an overlap of cooling and H_3BO_3 control methods. As a consequence post-LOCA LTC is assured for all break sizes.

The staff is continuing to conduct reviews of H_3BO_3 accumulation modeling and determination of the hot-leg switchover time to simultaneous injection. The issues include modeling of the decay heat generation rate, the appropriate margin for calculation of H_3BO_3 concentration, and determination of a conservative volume in which H_3BO_3 accumulates. These issues apply to a number of licensees and have been shown not to be safety-significant, and the staff is confident that a satisfactory resolution will not have a significant impact. Consequently, the issues are being addressed generically and, pending resolution, the licensee's analyses will be reviewed on a case by case basis, such as that described above.

Evaluation of SBLOCA

The staff has also performed a confirmatory analysis of the SBLOCA event, to verify the minimum two-phase level that was calculated by the CEFLASH-4AS thermal hydraulic blowdown code. The proposed increase in thermal power level will cause an increase in the core uncovery for the limiting SBLOCA event. A drift-flux model was developed to compute the two-phase level in the core during the time of maximum core uncovery for the 0.055 ft^2 cold leg break.

The licensee's analysis in Reference 10 predicts that the minimum level for the inner vessel two-phase mixture level, for the limiting 0.055 ft^2 cold leg break, occurs at about 1640 seconds into the event. Even though the RCS pressure decreases below the shut off head of the SIT, no credit for SIT injection was taken for this analysis. Therefore, only HPSI is available to maintain and control the minimum two-phase level in the core. In fact, at 1640 seconds for the 0.055 ft^2 cold leg break, HPSI just matches the boil-off in the core. This is the time, in this transient, where the RCS pressure has decreased sufficiently to enable the HPSI flow to match and then exceed the boil-off in the core due to decay heat. Since the HPSI flow just matches the core steaming rate at 1640 seconds, a balance equation can be written wherein injection from the HPSI equals the core boil-off due to decay heat or:

$$W_{hpsi} = \frac{F_{dh} Q}{h_{fg}} \int_{z_{sub}}^{z_{2\phi}} P_{ax}(z) dz$$

where

W_{hpsi} = HPSI injection flow rate, lbs/s
Q = core power, Btu/s
F_{dh} = decay heat multiplier
$P_{ax}(z)$ = axial peaking factor at elevation, z
Z_{sub} = subcooled level in core, ft
$Z_{2\varphi}$ = two-phase mixture height in core, ft
h_{fg} = latent heat of vaporization, Btu/lb

The balance equation, above, is solved to find the two-phase level in the core that produces the steaming rate that equals the HPSI injection into the RCS. This balance equation can be solved at any time during the transient since the two-phase level, governed by the steam release rate at the surface, will seek that value that equals the injection rate. At the time of the minimum level in the core for the 0.055 ft^2 cold leg break (i.e. at 1640 seconds), the injection into the RCS is 49.3 lbs/s. This injection rate is calculated from the transient RCS pressure and the HPSI head-flow curve, provided by the licensee in Reference 10. From the core power level and axial shape, the two-phase level can be readily computed using the following assumptions and conditions:

Q = 3735 MWt (3.54×10^6 Btu/s)
F_{dh} = 1971 ANS decay heat standard with a 1.2 multiplier
W_{hps}i = 49.3 lb/s
h_{fg} = 732 Btu/lb (@600 psia)

Using this input, the minimum two-phase level in the core at 1640 seconds for the limiting 0.055 ft^2 cold leg break was computed to be 7.3 ft. This level compares well with the licensee's value of about 7.2 ft. The minimum levels, calculated for the 0.05 and 0.06 ft^2 cold leg breaks, were also verified with this method.

The staff also utilized an alternate thermal hydraulic blowdown code to verify the system response for the limiting small break. This alternate methodology consisted of a semi-implicit solution of the conservation equations including a detailed drift-flux model to accurately model two-phase level swell. The alternate methodology was compared against a multitude of phenomenological problems (i.e., manometer oscillations with and without friction), separate effects tests, and integral experiments appropriate to validate the key phenomenological behavior characterizing SBLOCA response. The model was shown to reproduce the two-phase level and pressure transients for the limiting 0.55 ft^2 cold leg break. Based on the hand calculations and analyses with the alternate methodology, the staff confirms the results of the SBLOCA analyses performed with the CEFLASH-4AS code. From these calculations, the staff can conclude that CEFLASH-4AS is performing the correct fluid balance in the vessel for the Waterford 3 EPU SBLOCA analyses.

<u>Summary</u>

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The staff's review included selected confirmatory analyses of two-phase level in the core, during SBLOCA events. The staff's results were in good agreement with the licensee's results. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the RPS and the ECCS will continue to ensure that the PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and LTC will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LOCA ECCS performance criteria.

2.8.5.6.4 Small Primary Line Break Outside of Containment

This is bounded by the SBLOCA for the thermal-hydraulics and the radiological dose assessment is addressed in Section 2.9. No further discussion is provided here.

2.8.5.7 Anticipated Transients Without Scram

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC 20. The regulation at 10 CFR 50.62 requires that:

- Each pressurized water reactor must have equipment ... that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system.

- Each pressurized water reactor manufactured by Combustion Engineering or by Babcock and Wilcox must have a diverse scram system .... This scram system must be designed to perform its function in a reliable manner and be independent from the existing reactor trip system ....

The NRC staff's review was conducted to ensure that (1) the above requirements are met, and (2) the setpoints for the ATWS mitigating system actuation circuitry (AMSAC) and diverse scram system (DSS) remain valid for the proposed EPU. In addition, for plants where a DSS is not specifically required by 10 CFR 50.62, the NRC staff verified that the consequences of an ATWS are acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the MTC and the primary system relief capacity. The NRC staff reviewed the issue of ATWS protection at Waterford 3, in terms of the measures the licensee has taken to comply with the requirements of 10 CFR 50.62, and the expected effects, if any, of the proposed EPU upon those measures. Review guidance is provided in Matrix 8 of Reference 31.

Technical Evaluation

Waterford 3 has equipment that is diverse from the reactor trip system to automatically start the EFWS and trip the turbine, given an ATWS situation. Since Waterford 3 is a PWR manufactured by CE, the plant is also equipped with a DSS. This equipment, required by 10 CFR 50.62, will mitigate the consequences of an ATWS, regardless of power level. Therefore, raising the RTP, via the proposed EPU, will not affect the Waterford 3 plant's ability to cope with an ATWS event, and Waterford 3 would continue to be in compliance with the requirements of 10 CFR 50.62, should the proposed EPU be implemented.

Summary

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that the AMSAC and DSS will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

2.8.5.8 Asymmetric Steam Generator Transient

Regulatory Evaluation

The objective of the asymmetric SG transient (ASGT) analysis is to demonstrate that the ASGT event does not violate the DNBR and LHR SAFDLs for Waterford 3 with power uprate at 3716 MWt.

Technical Evaluation

The event is initiated by the inadvertent closure of a single MSIV, which results in a loss of load to the affected SG. Upon the loss of load to the single SG, its pressure and temperature increase to the lifting pressure of the secondary safety valves. The core inlet temperature of the loop with the affected SG increases, resulting in a temperature tilt across the core. The steam flow from the unaffected SG increases to pick up the lost load, causing a decrease in its temperature and pressure. This causes the core inlet temperature of the unaffected SG loop to decrease, thereby enhancing the temperature tilt at the core inlet. The CPC high differential cold leg temperature trip serves as the primary means of reactor protection for this transient.

The results of the licensee's analysis confirmed that the ASGT event does not violate the DNBR (>1.26) and LHR (< 21 kw/ft) SAFDLs for Waterford 3 with power uprate at 3716 MWt. Also, the ASGT event with power uprate at 3716 MWt does not violate the limits on maximum RCS and SG pressure.

Summary

The NRC staff has reviewed the information submitted by the licensee related to ASGT analysis and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ASGT event.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

Regulatory Evaluation

Nuclear plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

Technical Evaluation

The design of fuel assemblies that will be loaded into the EPU cores are unchanged from the current fuel assembly designs. Similarly, there is no change to the current limits on uranium loading, burnable poison concentration, and other parameters pertaining to new fuel storage criticality.

Therefore, the staff finds that the EPU will not affect the ability to store new fuel in a subcritical configuration.

Summary

The NRC staff has reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the SFP and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions, and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). The NRC's acceptance criteria are based on GDC-61, insofar as it requires that fuel storage facilities be equipped with cooling systems capable of reliably removing decay heat; and GDC-62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.2.

Technical Evaluation

The fuel assembly designs that will be loaded into the EPU cores are unchanged from the current fuel assembly designs. Similarly, there is no change to the current limits on uranium loading, burnable poison concentration, and other parameters pertaining to spent fuel storage criticality.

Therefore, the EPU will not affect the ability to store spent fuel in a subcritical configuration.

The licensee has also evaluated the effects of the EPU upon spent fuel storage water temperature, to ensure that the maximum bulk pool temperature limits of 140 °F, for a normal refueling outage, and 155 °F, for a full-core offload, will not be exceeded. The licensee's evaluations confirm that the current spent SFP system can remove enough decay heat to meet the maximum bulk pool temperature limits.

Summary

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel rack temperature and criticality analyses. The NRC staff also concludes that the spent fuel pool design will continue to ensure an acceptably low temperature and an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, the NRC staff concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs 4 and 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

2.9 Source Terms and Radiological Consequences Analyses

Introduction

To support the proposed increase in rated power, the licensee performed radiological consequences analyses of the DBAs for Waterford 3, assuming operation at the uprated power. The licensee analyzed the dose consequences of the following DBAs:

- Main Steam Line Break (MSLB)
- Single Reactor Coolant Pump (RCP) Shaft Seizure/Sheared Shaft
- Control Rod Ejection Accident (REA)
- Small Primary Line Break Outside Containment
- Steam Generator Tube Rupture (SGTR)
- Loss-of-Coolant Accident (LOCA)
- Fuel Handling Accident (FHA)

Reference 1 reported the results of these analyses in order to show compliance with 10 CFR Part 100 for offsite doses and 10 CFR Part 50, Appendix A, GDC 19, for the CR. The licensee analyzed the doses in the CR for only the LOCA and the FHA, because these were the only DBAs in the Waterford 3 UFSAR that included the CR analysis. The staff requested more information on the basis of the CR envelope unfiltered inleakage assumption used in the analyses, and also asked the licensee whether it had determined that GDC 19 is met for the other DBAs included in the Waterford 3 UFSAR. In the time since submittal of Reference 1, Entergy performed tracer gas testing of the CR envelope to quantify the CR inleakage. The results of the test were not bounded by the LOCA CR dose analysis previously submitted in support of the EPU.

The dose analyses submitted by the licensee to support the EPU used the original licensing basis source term for Waterford 3. The NRC staff reviewed these dose analyses to determine compliance with 10 CFR Part 100 and GDC 19 for operation at the proposed uprated RTP. As a result of staff questions on the licensee's CR habitability dose analyses and the basis for the CR unfiltered inleakage assumption, by Reference 11, as supplemented by References 14, 16, 17, 20, and 22, Entergy submitted a separate license amendment request for a full-scope implementation of an alternative source term (AST) and also requested that the CR habitability dose analyses in the AST amendment request supersede those in the EPU submittal. The licensee would show compliance with GDC 19 for the EPU through the analyses provided in the AST amendment instead of those provided in the original EPU submittal.

The AST license amendment request included descriptions of the licensee's dose analyses of DBAs, which were performed assuming operation at the EPU power level. These analyses provided CR and offsite dose results. Even though the NRC staff has reviewed the DBA dose analyses in the EPU with respect to the offsite dose to determine compliance with 10 CFR Part 100, the staff's finding of acceptability for the EPU will be based on finding that operation at the uprated power meets the requirements of 10 CFR 50.67, as well as GDC 19, for the separate AST license amendment request. The staff will not provide a technical evaluation of the licensee's dose analyses using the original licensing source term in this SE for the EPU, but will refer to the SE for the AST license amendment. The staff's finding of acceptability for the proposed increase in RTP is based on the AST application (Reference 11) showing compliance with 10 CFR 50.67 and GDC 19 and the staff's approval of the request for a full-scope implementation of an AST for Waterford 3 via letter dated March 29, 2005 (Reference 73). In addition, the source terms for the radwaste systems analysis, and atmospheric relative concentration estimates are also addressed in the SE for the AST amendment referenced above.

The NRC staff has reviewed the licensee's evaluation of the impact of the proposed EPU implementation within its review of the license amendment request for a full-scope implementation of an AST in Reference 11. The dose analyses in support of the AST show compliance with the dose criteria in 10 CFR 50.67 and GDC 19 for the proposed EPU.

Conclusion

Note: The following discussion is an excerpt rom the NRC's AST SE, Reference 73.

Implementation of the AST does not increase the quantities or alter the types of radioactive material actually released if an event were to occur. Implementation of the AST also has no effect on the actual or calculated effluents arising from normal operation. With respect to occupational doses, the AST is, again, only a change in dose calculation inputs and methodology. Calculated doses meet TEDE criteria. No aspect of implementing the AST involves facility equipment, procedure, or process changes that would increase actual onsite doses if an event were to occur. The AST does not result in actual or calculated changes in the normal radiation levels in the facility, or in the type or quantity of radioactive materials processed during normal operation. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure.

The NRC staff reviewed the assumptions, inputs, and methods used by Entergy to assess the radiological impacts of implementing a full-scope AST and EPU at Waterford 3. The NRC staff finds that Entergy used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified. The NRC staff compared the doses estimated by Entergy to the applicable criteria and finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and CR doses will continue to comply with these criteria, for DBAs at Waterford 3.

This licensing action is considered to be a full implementation of the AST. With this approval, the previous accident source term in the Waterford 3 design basis is superceded by the AST proposed by Entergy. The previous offsite and CR accident dose criteria expressed in terms of whole body, thyroid, and skin doses are superceded by the TEDE criteria of 10 CFR 50.67 or fractions thereof, as defined in RG 1.183. All future radiological analyses performed to demonstrate compliance with regulatory requirements shall address all characteristics of the AST and the TEDE criteria as described in the Waterford 3 design basis.

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation is conducted to ensure that operator performance is not adversely affected as a result of system changes required for the proposed EPU. The NRC staff's review covers changes to operator actions, human-system interfaces, and procedures and training required for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR 50.54(i) through (m), 10 CFR 50.59, 10 CFR 50.120, 10 CFR 55.46, and 10 CFR 55.59. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for the review of the human factors area. The licensee has addressed these questions in the February 5, 2004, public meeting between the licensee and the NRC staff, and in its response, Reference 4, to the NRC staff's RAI. Following are the NRC staff's questions, the licensee's responses, and the staff's determination of acceptability.

1. Changes in Emergency and Abnormal Operating Procedures

   Describe how the proposed EPU will change the plant emergency and abnormal procedures. (SRP Section 13.5.2.1)

In Reference 1, Entergy stated that the existing procedures will adequately cover emergency scenarios, abnormal occurrences, and normal operations related to the EPU, and new procedures were not expected to be required. The licensee will update affected setpoints in the emergency and abnormal operating procedures with the new EPU values at the end of RFO13. A specific, non-setpoint change will be the change in the time available from 2 to 4 hours to 2 to 3 hours for establishing simultaneous hot and cold leg injection in the LOCA emergency operating procedure (EOP). The licensee indicated that this change will be implemented through its procedure change process, as well as through operator training. Taking into consideration the type of manipulations involved in this task, the NRC staff does not expect the change to have a significant effect on the successful execution of the action. The only other changes in procedures are related to the operation of the combustible gas control system, which will be addressed in a separate license amendment to request the elimination of the TS requirements for combustible gas control in containment.

The licensee indicated that the operating procedure changes due to the EPU are minor and do not result in significant changes in the operating philosophy. In addition, the licensee committed to providing training to cover any procedure changes related to the EPU. Therefore, because no new procedures are required and the licensee will provide training to address changes to the current procedures, and considering the type of manipulations associated with and time available for establishing hot and cold leg injection post LOCA, the NRC staff finds the licensee's proposed changes in this area (not including those involved with the combustible gas control system) to be acceptable.

2. <u>Changes to Operator Actions Sensitive to Power Uprate</u>

> Describe any new operator actions required as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal procedures that will occur as a result of the proposed EPU. (SRP Section 18.0)

The licensee indicated that no new operator actions in emergency or abnormal operating procedures are anticipated as a result of the proposed EPU. The ADVs will have a TS-mandated automatic setpoint, and operators will be required to perform channel checks once every 12 hours to ensure ADV automatic actuation operability when operating above 70 percent RTP. The licensee did not anticipate that these channel checks should have any impact on operator response times and indicated that classroom training/testing along with simulator training/testing will be conducted to ensure operators' understanding of the change.

Table 2.11-1 of the submittal, titled "Impact of EPU on HRA [Human Reliability Analysis] Time Available," listed several operator recovery actions for which the available time to accomplish each task will be reduced as a consequence of the EPU. Because the times available for successful completion are decreased, the licensee stated that those actions are assumed to be failed in their risk assessment, and the failure probabilities for those actions have been set to 1.0. Therefore, credit is not taken in the licensee's risk assessment for these manual recovery actions. Although the remaining operator actions are shown in the table to have increased times available for EPU, this is a result of conservatisms in the original (pre-EPU) model. These operator actions are also expected to have decreased times available as a result of EPU, but the impact of these time decreases is small compared to the effect of decreases in loss of offsite power recovery times, which are explicitly included in the licensee's risk assessment for EPU. This is discussed further in Section 2.13 of this SE. Section 2.13 also provides discussions on the specific examination of operator actions by the licensee's Level 1 internal flood risk evaluation, Level 1 internal fire risk evaluation, and shutdown risk evaluation. No significant adverse effects were identified due to EPU-caused decreases in operator response times by these evaluations.

Based on the licensee's commitments for the new channel check and the type of action involved, the staff is satisfied that the checks can be successfully executed. Additionally, since 1) the licensee is not taking credit in their risk assessment for the manual actions identified in Table 2.11-1 as having decreased times available under the EPU, 2) the effect of decreases in loss of offsite power recovery times, as well as for the other areas described above, have been explicitly included in the licensees risk assessment, and 3) the impact of decreases in time available to perform remaining credited manual actions is small compared to the impact of decreases in loss of offsite power recovery times, the staff finds the changes to be acceptable. The effects of setting the probabilities of manual actions to assumed failure on any risk assessment results and the impact of decreases in offsite power recovery times are evaluated in Section 2.13 of this SE.

3. <u>Changes to Control Room Controls, Displays, and Alarms</u>

> Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal, and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, and alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU, and how operators were tested to determine they could use the instruments reliably. (SRP Section 18.0)

Table 2.9-1 of Reference 1, as modifies by References 5 and 10, provided a summary of the control room controls, displays, and alarms that would be affected with details on the setpoints/ranges before and after the EPU.

The licensee stated that the indications listed in the Table would provide operators with the information required to achieve and maintain safe shutdown of the reactor during normal and accident conditions. The licensee explained that operators have been involved in the design and review of the modification packages for the changes, and that multiple layers of operator involvement have been in-place to assure operator cognizance of the changes. In addition, operators will receive training, using the systematic approach to training process, on the changes to ensure that they will be able to use the instruments reliably.

The purpose of this question was to ensure that the licensee has adequately considered the equipment changes resulting from the EPU that affect operators' ability to perform their required functions. Based on the licensee's response, the NRC staff is satisfied that the licensee has done so.

4. <u>Changes on the Safety Parameter Display System</u>

> Describe any changes the proposed EPU will have on the safety parameter display system (SPDS). How will the operators know of the changes? (SRP Section 18.0)

The licensee noted that any changes to the SPDS as a result of the EPU are also included in the contents of Table 2.9-1 and are the same as those described for the previous question. Additional changes to the SPDS, to be implemented at the end of RFO13, would be in the color banding for the following parameters: pressurizer pressure narrow range, pressurizer pressure wide range, RCS cold leg temperature, RCS hot leg temperature, and safety injection tank (SIT) levels. For all of the proposed changes, the licensee asserted again that multiple layers of operator involvement have been in place to assure operator cognizance of the changes. The licensee also committed to training and testing operators on the use of the display changes to ensure reliable performance. Since the licensee has committed to involving and training operators on the implementation of the changes, the NRC staff finds the proposed changes to the SPDS to be acceptable.

5. Changes to the Operator Training Program and the Control Room Simulator

Describe any changes the proposed EPU will have on the operator training program and the plant reference control room simulator, and provide the implementation schedule for making the changes. (SRP Sections 13.2.1 and 13.2.2)

The licensee stated that training, to be determined by its Operations Training Review Group, will be completed by the end of RFO13. The training for the EPU will follow a systematic approach to training process and will include procedure changes, new or revised TSs/safety analysis, and equipment modifications. The training will be given prior to shutdown for refueling, and the licensee will also conduct startup training for operations crews prior to the conclusion of the outage.

In regard to the control room simulator, the licensee indicated that the simulator will be upgraded before EPU implementation, at the beginning of the last operator training cycle prior to RFO13, to provide training to operators at EPU conditions. The upgrade will incorporate any plant modifications that affect the primary, secondary, control systems logic, or dynamic processes. Additionally, the simulator will be updated to reflect plant computer and display changes, as well as new or modified instructor station malfunctions, remote functions, overrides, and panel and piping graphics. In Reference 1, the licensee also provided the information sources used to obtain the simulator modification, design, analysis, and test data. The licensee has committed to performing verification and validation testing on the modifications when 100 percent power initial conditions are established and to compare actual plant data to the simulator during Cycle 14. The new data will be used to supplement the baseline data in conducting ANSI/American Nuclear Standards (ANS) 3.5 testing.

The licensee concluded in Reference 1 that the training program and updates to the simulator will ensure operator understanding of the changes to plant systems and the associated effects on the operation of the plant related to the EPU. The NRC staff is satisfied that, based on the above commitments, the licensee will develop and implement a satisfactory training program, including simulator training, for the proposed EPU.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that (1) the licensee has appropriately accounted for the effects of the proposed EPU on the available time for operator actions, and (2) the licensee has taken appropriate actions to ensure that operators' performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of 10 CFR 50.54(i) through (m), 10 CFR 50.59, 10 CFR 50.120, 10 CFR 55.46, and 10 CFR 55.59 following implementation of the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

Background

Guidance for reviewing EPU test programs is described in NUREG-0800, SRP 14.2.1, “Generic Guidelines for EPU Testing Programs,” and provides reasonable assurance that the proposed testing program verifies that those plant SSCs are affected by the proposed power uprate will perform satisfactorily in service at the proposed power uprate level. The staff review focused on the licensee’s adequately addressing the guidance described in SRP 14.2.1.

2.12.1 Approach to Extended Power Uprate Power Level and Test Plan

Regulatory Evaluation

The purpose of the EPU test program is to verify that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff’s review included an evaluation of (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) integrated plant systems testing, including transient testing, if necessary, to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program’s conformance with applicable regulations. The NRC’s acceptance criteria for the proposed EPU test program was based, in part, on (1) 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service; (2) GDC 1, insofar as it requires that SSCs important to safety be tested to quality standards commensurate with the importance of the safety functions to be performed; (3) 10 CFR 50.34, “Contents of Applications: Technical Information,” which specifies requirements for the content of the original operating license application, including UFSAR plans for pre-operational testing and initial operations; and (4) RG 1.68, Appendix A, Section 5, “Power Ascension Tests,” which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions and, to the extent practical, during and following AOOs.

Technical Evaluation

1. SRP 14.2.1 Section III.A. - Comparison of Proposed Test Program to the Initial Plant Test Program

SRP 14.2.1, Section III.A, specifies the guidance and acceptance criteria that the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include (1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison, or adequately justify proposed deviations from the initial power-ascension test program. The following specific criteria should be identified in the EPU test program:

- all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level

- all initial test program tests performed at power levels lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU

- differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

Evaluation

The staff found that Section 14.2.7 of the Waterford 3 UFSAR committed to a startup test program structured in accordance with RG 1.68, Revision 2, “Initial Test Programs for Water-Cooled Nuclear Power Plants,” and the ANSI standards regarding the qualification of startup testing personnel for the original program. The staff found that those commitments were also part of the proposed EPU test plan.

The staff reviewed the following EPU test plan information provided by the licensee in order to verify that the initial EPU license amendment submittal, supplemental information provided in response to staff RAIs, and applicable sections of TSs and the UFSAR addressed the specific criteria for an adequate EPU test program, as described above. Specifically, the following documents were reviewed during the staff’s evaluation:

C FSAR Section 1.1.3, ”Test Program” - An overview of the initial power ascension test program from initial fuel loading through 100 percent power.

C FSAR Section 14, “Initial Test Program” - Provided a detailed description of the regulatory basis for the program; the initial startup test program; and the overall test objectives, methods, and acceptance criteria.

C Reference 1, Attachment 5, Section 2.10, “Power Ascension Testing” - Described an overview of the test plan for the approach to the EPU power level.

C Reference 2 - Provided a brief description of planned EPU modifications, affected system(s), and proposed post-modification test plans.

C Reference 2, Attachment 2, “Aggregate Impact of Extended Power Uprate Modifications” - Described the aggregate impact on dynamic plant response and the effect on individual equipment design and control functions related to the EPU modifications.

C Reference 2, Attachment 3, “Extended Power Uprate Test Plan” - Described the EPU-related tests and the power level at which the tests will be performed during power ascension.

C Reference 2, Attachment 4, “Comparison of Original Power Ascension Testing to Planned Extended Power Uprate Testing” - Described the original tests, the associated UFSAR section, the power level(s) at which the test was performed, and an evaluation of the test as it pertained to the proposed EPU test program.

- Reference 2, Attachment 5, "Justification for Exception to Large Transient Testing" - Described the basis for determining the exclusion of transient tests for the EPU.

- Reference 10, Attachment 5 and 6 - Described the determination that replacement digital ADV controllers and larger MSR relief valves were no longer being considered as modifications required for the EPU project.

- Reference 27, Attachment 1, "Supplement to Amendment Request NPF-38-249 Extended Power Uprate," - Clarified the licensee's position on an initial response to an RAI dated November, 8, 2004.

The staff found that all tests described in the initial startup test program were addressed in the description of the proposed EPU test program. In addition, a licensee evaluation of the initial test program found no examples of tests performed at lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU. The staff found the licensee determination in that regard acceptable.

The staff also noted the following test description differences for the proposed EPU testing as it related to the initial power ascension test program described in UFSAR Section 14.2.12.3.3.

Load changes and steady-state testing concerned control systems performance during steady-state operation, which will monitor and collect data at numerous power levels between 0 percent and 100 percent. Steady-state conditions will be established and control systems monitored at various power levels greater than the original licensed power; specifically 92.5 percent, 95.0 percent, 97.5 percent, and 100 percent post-EPU. As discussed in this SE, the staff found the proposed monitoring and data collection to be in accordance with SRP 14.2.1.

Load change/ramp change testing will be an integrated systems test planned by changing power from 100 percent to 90 percent, followed by an increase in power from 90 percent to 95 percent. All control systems will be in automatic mode for the test with the exception of the CEDMCS, which will be in manual mode as required per plant procedures. Reactor power will be controlled during the test with the CVCS. The staff found the proposed Load Change/Ramp Change testing to be adequate.

Control system transient testing was performed during initial startup testing for the SBCS, FW control (FWC), and RRS. As described in the initial Waterford 3 Startup Report, an individual control system transient test was performed for SBCS at 50 percent power only, an individual control system transient test was performed for FWC at 50 percent and 80 percent power only, and an individual control system transient test was performed for RRS at 50 percent and 100 percent power only. Modifications to control systems were required for the EPU to ensure the plant would be maintained within desired operating bands during normal operations, and would stabilize during minor load changes and load rejection events. The modifications did not change the design functions of the equipment or the method of performing or controlling the function. The changes to the SBCS, FWC, and RRS were setpoint adjustments only; no physical changes were performed. The licensee will perform a channel calibration to verify the proper operation of each control system in response to changes in input parameters. Control system transient testing will not be performed at 50 percent nor 80 percent power for the EPU. This was considered acceptable since the plant has operated at those power levels prior to the planned power uprate. As stated by the licensee, repeating the tests at pre-EPU power levels would not confirm any new or significant aspect of performance that had not already been demonstrated by previous operating experience or routinely demonstrated through plant operation. In addition, the new setpoints had been evaluated at the EPU power level using the LTC computer code, with acceptable results. No new system interactions or unacceptable transient behavior of control systems were identified. The staff also noted that, of the control system transient tests performed during initial startup, only the test of the RRS was performed at greater than 80 percent power. This test involved changing the turbine load and observing the RRS response to a change in reactor power by operating CEDMCS in the auto-sequential mode. With the exception of a reactor power cutback (RPC), plant procedures no longer provide for use of the RRS for the control of reactor power. Rather, reactor power is controlled through the addition or removal of soluble boron from the RCS via the CVCS. Since Waterford 3 no longer uses the RRS to control reactor power at 100 percent, the control system transient test of the RRS at 100 percent will not be performed. The RRS is used to stabilize reactor power between 50 percent and 70 percent following a RPC. As discussed above, control system transient testing will not be performed at these power ranges, since the plant has been operated at these power levels prior to power uprate. However, channel calibration of the individual control systems, and integrated testing at steady-state and during ramp unit load change, as described above, will be performed to demonstrate acceptable control system performance. The staff found the proposed control system performance testing to be adequate.

The staff also reviewed information contained in the license amendment application, supplemental information, and the UFSAR regarding low power physics testing and RCS thermal power determination calculations. The staff found that the low power physics testing, as stated in UFSAR Sections 1.2.4 and 1.1.3.b., consisted of a series of tests performed after the reactor was taken critical and sustained critical operation without producing measurable nuclear heat. The test then compared measured results to predicted values. These values will remain unchanged for the EPU; however, the test will continue to be performed at each core reload, including the reload associated with the EPU, in accordance with TS requirements. The RCS thermal power determination calculation was a manual calculation performed to establish a standard thermal power for first time use during original startup testing. The calculated power level was then used as the standard for calibrating the CPC and excore nuclear instrumentation. Currently, and for the EPU, the COLSS is used for the calculation, which is then used to calibrate the CPCs and excore nuclear instrumentation. The manual calculation is no longer needed, since baseline information from previous operating history was available.

Summary

The staff concluded, through comparison of the documents referenced above and a review of test commitments referenced in the UFSAR, that the proposed EPU test program adequately identifies (1) all initial power ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria. Additionally, the staff accepted the licensee's evaluation that there were no examples of tests performed at lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU. The staff also concluded that, in determining EPU test requirements, the licensee had adequately evaluated the need for any additional low power physics testing and RCS thermal power determination calculations.

2. <u>SRP 14.2.1 Section III.B.- Post Modification Testing Requirements for Structures, Systems, and Components Important to Safety Impacted by Extended Power Uprate-Related Plant Modifications</u>

SRP 14.2.1, Section III.B, specifies the guidance and acceptance criteria that the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant, and include events such as loss of all offsite power, tripping of the main turbine generator set, and loss of power to all RCPs. The EPU test program should adequately demonstrate the performance of SSCs important to safety meet all of the following criteria: (1) the performance of the SSCs is impacted by EPU-related modifications, (2) the SSC is used to mitigate an AOO described in the plant-specific design basis, and (3) the program involves the integrated response of multiple SSCs. The following should be identified in the EPU test program as it pertains to the above paragraph:

- plant modifications and setpoint adjustments necessary to support operation at power uprate conditions, and

- changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions.

<u>Evaluation</u>

The staff reviewed the planned EPU modifications and its potential effects on SSCs, as documented in References 1, 5, and 10. The post-modification tests were judged to be the acceptance tests to demonstrate design function performance and integration with the existing plant. The staff also reviewed the basis for the licensee conclusions that the modifications did not change the design function of the SSCs or the methods of performing or controlling their functions, as described in Attachment 1 of Reference 2. The following modifications and post-modification test (PMT) descriptions were reviewed by the staff.

C Plant Protection System - The low SG pressure trip bistable and annunciator setpoints will be reduced to provide adequate operating margin following the EPU. The change to the low SG trip setpoint was required to provide operating margin and prevent spurious trips. Since the EPU design will maintain the RCS hot leg temperature at a nominal 601 °F, operating SG pressures would be close to the current low pressure trip setpoint, which could cause spurious trips. The proposed low SG trip setpoint was incorporated into the EPU safety analysis. The design function of the setpoint, as discussed in TS Bases 2.2.1, will remain the same. The PMT will consist of a channel calibration and functional test.

C Atmospheric Dump Valves - The SBLOCA analysis for the EPU required crediting the ADVs with having a lower opening pressure setpoint when RTP was greater than 70 percent, to ensure 10 CFR 50.46 (acceptance criteria for ECCSs) criteria were met. The proposed ADV opening setpoint was incorporated into the EPU safety analysis. The PMT will be a channel calibration and functional test of the ADVs.

C Main Turbine - The high pressure turbine modification will consist of installing a new high pressure turbine rotor with all-reaction blading, a new inner cylinder with stationary blading, a new inlet flow guide, and new steam sealing components. The new steam path will change normal turbine control operation from sequential valve operation to single valve operation. The modification will not impact the turbine throttle or governor valves. The current control system does allow for single valve operation during startup and turbine valve testing. The PMT will be a baseline performance test, main turbine overspeed test, vibration monitoring, and validation of the COLSS.

- Main Generator - A rewind of the stator, increased cooling, and installation of a new stator cooling water alkalizer skid will occur. The modifications will be required due to the normal degradation and corrosion experienced in the stator cooling water coils. The stator rewind will allow the main generator to operate at the EPU-rated electrical output, and the water alkalizer skid will enhance the reliability of the generator by minimizing corrosion to the stator cooling water coils. The function of the main generator and its response to a turbine runback/setback will not be affected by the modifications. The PMT will consist of electrical tests to verify operation within the original generator capability curve, chemistry monitoring of stator cooling water, vibration monitoring, and isophase bus duct temperature monitoring.

- Main Transformer - Main Transformer ‘A’ will be replaced and the cooling will be upgraded on Main Transformer ‘B’ to accept the proposed EPU operating conditions. The PMT will be performed to test oil samples for degradation, and periodically survey 230 kV line connection temperatures. The design function of the system will not change due to EPU modification.

- Generator Output Breakers - The existing oil circuit breakers will be replaced with high capacity gas circuit breakers to accept the proposed EPU operating conditions. The PMT will be executed to verify proper operation of trip circuits, perform AC and DC acceptance tests, perform electrical tests to verify breaker operation, and verify proper calibration of synchronization check circuit.

- Feedwater Heater Drain System - The normal and/or alternate FW heater level control valves will be upgraded or replaced to accept the proposed EPU operating conditions. The PMT will verify that feedwater heater levels are maintained in the normal operating band, and ensure valve seat leakage and stroke time are within design limits.

- Main Condenser - Additional main condenser tube support will be added to minimize the effects of flow-induced vibration for the proposed EPU operating conditions. The PMT will consist of monitoring secondary system chemistry parameters.

- Plant Control Systems/Instrumentation - The RCS pressurizer level control setpoints will be revised, FWCs will be adjusted, steam bypass controls will be adjusted, the qualified safety parameter display system will be modified, and the FW and MS instrument displays will be re-spanned. The changes are required to ensure that, under EPU conditions, the plant will be maintained within normal operating bands during normal operations and will stabilize the plant during minor load changes and load rejection events. The modifications will not change the design function or method of controlling the function. The computer code used to simulate the changes was previously used in developing the current system settings and was benchmarked against actual plant events. The PMT will consist of a channel calibration and functional test, and load change testing to verify auto operation of the various control systems.

The licensee stated that evaluations of the actual test results may identify the need for additional tests or revision of the tests planned and, therefore, the final test plan may be revised.

The staff also reviewed the EPU modification aggregate impact analysis in Reference 5. The staff noted that, where a potential aggregate impact was identified, the modification was modeled into the applicable EPU safety analysis or was evaluated utilizing LTC computer code analyses. The LTC code was benchmarked against actual plant data, including steady-state conditions and three separate plant transients. A total of 32 different cases were run to model EPU conditions and, based upon the data sample reviewed by the staff, no unacceptable system interactions or dynamic system responses were identified by the licensee. As described in the initial licensee analysis, the aggregate impact of the modifications would not result in a significant change to the plant's dynamic response to anticipated initiating events or normal operations. The staff also verified that the licensee adequately identified functions important to safety, setpoint adjustments, and changes in plant operating parameters affected by the EPU modifications.

Summary

The staff concluded, based on review of each planned modification, the associated post-maintenance test, and the basis for determining the appropriate test, that the EPU test program will adequately demonstrate the performance of SSCs important to safety and included those SSCs (1) impacted by EPU-related modifications, (2) used to mitigate an AOO described in the plant design basis, and (3) that supported a function that relied on integrated operation of multiple systems and components (i.e. Plant Control Systems - Pressurizer Level Control).

The staff concluded that the proposed test program adequately identifies plant modifications and setpoint adjustments necessary to support operation at the uprated power level and changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions. Additionally, the staff determined there were no unacceptable system interactions because of modifications to the plant.

3. SRP 14.2.1 Section III.C. - Justification for Elimination of Extended Power Uprate Power-Ascension Tests

SRP 14.2.1, Section III.C, specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be considered for inclusion in the EPU test program, pursuant to the review criteria of Sections 1. and 2. above. The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- previous operating experience,
- introduction of new thermal-hydraulic phenomena or identified system interactions,

- plant staff familiarization with facility operation and trial use of operating and emergency operating procedures,
- margin reduction in safety analysis results for AOOs, and
- risk implications.

Evaluation

The staff reviewed information regarding the following deviations or exceptions to original startup testing contained in References 2 and 5.

- SIT-TP-707, “Steam Bypass Control System Capacity Checks” - The licensee stated in their RAI response that, in lieu of this test, performance of a channel calibration of the SBCS and each ADV will demonstrate proper system response to changing plant parameters and will validate the assumptions of the calculation related to system response. The calculation was the basis for the licensee concluding that the SBCS will actuate prior to the ADVs in the event of a load reject from 100 percent power. The licensee’s calculation demonstrates that the likelihood that the SBCS will actuate prior to the ADVs in the event of a load rejection will be less after the EPU than under current plant conditions. Based on the changes, the staff concludes that the channel calibration of SBCS and the ADVs is an acceptable test method.

- SIT-TP-743, “Ventilation Capability” - The initial power ascension ventilation testing was conducted under the original plant design conditions. These conditions included a RCS hot leg temperature of 611 °F and a MS header pressure of 900 psia. The proposed EPU nominal operating RCS hot leg temperature will be 601 °F at a MS header pressure of 810 psia. For areas inside containment, the EPU does not propose any physical modifications that would add additional heat loads or increase demands on operating equipment during a plant cooldown or LOOP.

- SIT-TP-721, “Load Changes” - A test to gather data as part of the EPU power ascension test plan will be performed and integrated with EPU modification tests on the plant control systems to verify proper integrated system response. The modification tests are described above.

- SIT-TP-724, “Temperature Decalibration Verification” - The algorithms contained in the CPC were unchanged for the EPU. The “update” algorithm within CPCs accommodates for changes in cold leg temperature. The DNBR algorithm limits on minimum and maximum cold leg temperature of 495 °F and 580 °F are not impacted by the proposed change in TS limits on cold leg temperature and thus do not require revision for EPU.

The staff also reviewed Attachment 5 to Reference 1, Reference 10, and Reference 27 for the justification for exception to large transient testing. The licensee cited industry experience at ANO, a similarly designed plant at which a 7.5 percent EPU demonstrated that plant performance was adequately predicted under EPU conditions. Additionally, the following transients experienced at Waterford 3 were another factor used to evaluate the need to conduct large transient testing for the EPU.

- Turbine trip from 100 percent power (February 14, 2003) - A reactor cutback signal was automatically generated and lowered reactor power to within the capability of the SBCS, which was then available to mitigate the transient.

- FW pump trip from 100 percent power (June 3, 2001) - A reactor cutback signal was initiated; control systems operated as designed with no challenges to safety systems.

- Reactor trip from 82 percent power (February 13, 2001) - A component failure caused a turbine governor valve to cycle open and closed, which caused an increase in reactor power followed by a reactor trip on a variable over-power trip signal. The plant operated as designed with the FW and SBCS in automatic mode. SG pressure and level responded normally.

The staff also reviewed the following technical justifications provided by the licensee for not performing large transient testing.

- Remote Reactor Trip with Subsequent Remote Cooldown - The initial remote reactor trip with subsequent remote cooldown startup test concluded that the plant design was adequate to control the plant at remote locations. The test, which was performed from 20 percent power, also concluded that procedures used to perform the test were adequate. The EPU will not modify or change the reactor trip breakers or any trip system components that could affect the reactor trip system or remote shutdown capability. Additionally, the EPU will not affect the transfer and isolation capability to the remote shutdown panel (RSP) or change operational procedures for a RSP and subsequent plant cooldown. The EPU will rescale plant instrument meters to reflect the new EPU operating parameters. The changes to the RSP will be functionally tested during modification acceptance testing. The original test was performed from a low power level (approximately 20 percent power), which is unaffected by the EPU.

- Eighty Percent Power Total Loss of Flow/Natural Circulation Demonstration - The test was successfully performed at lower than proposed EPU conditions, and successfully demonstrated that plant response was within design and able to achieve natural circulation following the transient. The natural circulation behavior of the RCS will remain unchanged for EPU conditions, as determined by operational data used in the computer code model for the EPU UFSAR Chapter 15 safety analyses; previous plant operating experience was also factored into the computer code model. The flow coastdown analysis for the EPU was updated to account for increased SG tube plugging allowances and was benchmarked against plant data. Additionally, the original test was performed from approximately 20 percent power.

- Loss of Offsite Power Trip - The test was originally performed to demonstrate plant performance under a total loss of AC power. The test verified that the reactor could be shut down and hot standby conditions achieved and maintained using the EDGs, the source for engineered safety features power. The test also demonstrated, by simulating a total loss of AC power, the ability to remove decay heat with natural circulation flow in the RCS and with secondary feed from the steam driven EFW pump.

  There were no modifications associated with the EPU that would impact the ability of the EDGs to supply loads or affect load sequencing under LOOP conditions. The impact of the

EPU upon diesel loading was assessed and documented in Section 2.3 of Reference 1 and reviewed by the staff. Additionally, Entergy documented its response to 10 CFR 50.63, “Loss of all alternating power,” in a memo dated April, 14, 1989, in which plant procedures were reviewed and modified to meet the guidelines of NUMARC 87-00. The UFSAR evaluation of SBO is discussed in Section 8.1.A. SBO coping strategy was also discussed in Section 2.3.5 of Reference 1 and concluded that the plant is capable of maintaining the RCS in a hot standby condition and removing decay heat during a four-hour SBO post-EPU.

- Hundred Percent Power Turbine Trip - The original test was performed to demonstrate that plant design was adequate to respond to a 100 percent turbine trip and that plant systems responded as designed. Data obtained from the plant response were used to verify the computer code model predictions, which were used for modeling plant transients. The dynamic response of the MS piping, monitored during the turbine trip, was also demonstrated to be acceptable.

  No major hardware modifications are planned for the EPU that will modify the NSSS or MS piping. The EPU will result in plant operation at a lower SG pressure and higher steam flow, and adjustments to the SBCS will be made to compensate for those effects. The effects were also considered and evaluated by computer code analyses, which were performed to investigate and support the proposed control system changes for the EPU. Introduction of turbine trip is a transient initiator for the plant. Additionally, previous operating experience demonstrated that the plant design was adequate to respond to a 100 percent (92.5 percent EPU) power turbine trip with plant systems responding in accordance with design.

- Reactor Power Cutback System Loss of Load/Feedwater Pump Testing - The primary purpose of the RPC System (RPCS) is to prevent a reactor trip due to turbine trips, loss of a feedpump, or load rejection. The original test was designed to verify the interaction of the RPC and turbine systems in response to various transients, such that there would be no ESFAS actuation, no reactor trip, and no lifting of primary or secondary code safeties. This non-safety system test was deleted from the initial power ascension testing program. The primary purpose of the system was economic, to prevent a reactor trip, and the system has no safety function. If the system fails to stabilize the plant following a transient, safety systems will function to trip the plant. Based on accurate LTC computer code modeling for EPU conditions and actual plant transient response at the current 100 percent power level, further transient testing will not be performed.

- Natural Circulation Demonstration - The original test was performed to collect data to show that natural circulation flow conditions and heat removal capability were in accordance with design. During performance of the test, steady-state natural circulation conditions were maintained for approximately one hour. Additional natural circulation conditions were observed at reduced pressure to demonstrate that natural circulation could be maintained at reduced system pressure and that proper loop subcooling could also be maintained.

  Based on the results of analytical and computer code modeling, natural circulation behavior will remain essentially unchanged for the EPU. RCP response times were previously established and plant procedures currently exist to ensure that the plant equipment will fulfill the TRM response time assumed in safety analyses. The slight increase in decay heat associated with the EPU would have negligible impact on system capabilities, and there was no change in thermal-hydraulic phenomena or behavior noted in the computer model analyses. Additionally, no change in core mechanical design is associated with the EPU.

The staff review found that in justifying the EPU test exceptions described above, the licensee plans to conduct classroom training to review any changes in normal, abnormal, and emergency operating procedures and provide associated topical simulator training. The staff also noted that in describing and justifying test exceptions or deviations, the licensee adequately considered previous operating experience, the possible introduction of new thermal-hydraulic phenomena or system interactions, and margin reduction in safety analysis results for AOOs. Additionally, the staff found that, although risk implications were discussed in justifying elimination of tests, risk was not the sole factor used to determine test elimination. Other factors used to determine EPU test elimination included use of baseline operational data, updated computer modeling analyses, and industry experience.

Summary

The staff concluded that, in justifying test eliminations or deviations, the licensee adequately addressed factors, which included previous operating experience, introduction of new thermal-hydraulic phenomena or system interactions, and staff familiarization with facility operation and use of normal operating and emergency operating procedures. The staff noted that although qualitative risk implications were considered, in no instance did the licensee depend primarily or solely on risk as the basis for not performing the large transient tests. The staff also noted that the licensee could not follow vendor topical report guidance since none had been developed for CE EPU licensing applications. The staff determined that the licensee did not rely on analytical analysis as the sole basis for elimination of a power ascension test from the proposed EPU test program. Construction, installation, and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures. The final acceptance tests will demonstrate that the modifications will perform under their design function and integrate appropriately with the existing plant.

4. SRP 14.2.1 Section III.D. - Adequacy of Proposed Testing Plans

SRP 14.2.1, Section III.D, specifies the guidance and acceptance criteria that should be used to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the plant is capable of operating within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation shall be verified to be operable in accordance with existing TS and QA Program requirements. The following should be identified in the EPU test program:

- the method in which the initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,

- appropriate testing and acceptance criteria to ensure that the plant responds within design predictions, including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant,

- contingency plans if the predicted plant response is not obtained, and

- the test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

The staff reviewed Section 2.10 of Reference 1 and Reference 27, which described power ascension tests as they relate to the proposed EPU implementation. Additionally, Reference 74 details the Plant Systems Branch's conclusions regarding the impact of the EPU on the secondary side. The Plant Systems Branch determined that the scope of modifications was adequately addressed by the proposed post modification tests.

Evaluation

The staff reviewed Section 2.10 of Reference 1, which described power ascension tests as they relate to the proposed EPU implementation. The staff found that the licensee adequately addressed EPU operating experience for plants of similar design (ANO-2) in determining the current proposed test plan for Waterford 3. The staff also found:

- The proposed tests and test plan addressed the effects of any new thermal-hydraulic phenomena or system interaction that may be introduced by the EPU through computer model analyses and/or operating plant experience.

- The plant staff, through classroom and/or simulator training, will be familiarized with the operation of the plant under EPU conditions. The training will include plant modification and parameter value changes, implementation/execution of normal, abnormal, and emergency operating procedures, and accident mitigation strategies.

- Risk-informed justifications for not performing transient tests were considered but were not used as the sole factor in determining elimination of those tests. Previous operating experience, the initial startup test program report, and computer model analyses were the major influence on those decisions.

Additionally, during the tests, additional data will be taken at 2.5 percent increments from the previous full-rated power level of 3441 MWt to the EPU rated power level of 3716 MWt. Steady-state data will be taken at 92.5 percent power so that operating performance parameters can be projected for the uprated power. The data will then be evaluated against design predictions and any identified discrepancies will be resolved prior to continuing with power ascension. Waterford 3 management and experienced test personnel will evaluate all significant test deficiencies and anomalies at each 2.5 percent power plateau before proceeding with the power ascension. Although no final test schedule has been developed, the staff noted that Waterford 3 will follow typical startup procedures and TS requirements when the EPU is implemented.

Summary

The staff concluded that the proposed test plan will be performed by qualified personnel and will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility. Additionally, the staff concluded that the test schedule will be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans exist if predicted plant response is not obtained.

Conclusion

The staff has reviewed the EPU test program in accordance with SRP Section 14.2.1. This review included an evaluation of (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations. For the reasons set forth above, the staff concludes that the proposed EPU test program provides reasonable assurance that the plant will operate in accordance with design criteria and that SSCs affected by the EPU or modified to support the proposed power uprate will perform satisfactorily while in service. On this basis, the staff finds that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Therefore, the NRC staff finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of Extended Power Uprate

Regulatory Evaluation

A risk evaluation is conducted to (1) demonstrate that the risks associated with the proposed EPU are acceptable and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19, special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements. The NRC staff's review covers the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review covers the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEEs), or by an industry peer review. The NRC's risk acceptability guidelines are contained in RG 1.174. Specific review guidance is contained in Matrix 13 of Reference 31 and its attachments.

Technical Evaluation

The staff reviewed the risk evaluation submitted by the licensee in References 1 and 8. In general, the licensee's risk evaluation compared the risks of the pre-EPU to the post-EPU plant design and operation. A combination of quantitative and qualitative methods was used to assess the risk impacts of the proposed EPU. The following sections provide the staff's technical evaluation of the risk information provided by the licensee.

Level 1 Internal Events Risk Evaluation

The licensee maintains a Level 1 probabilistic risk assessment (PRA) of Waterford 3 that estimates the CDF due to internal initiating events. The risk impacts of the proposed EPU due to internal initiating events were assessed by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements as needed to capture the risk impacts of the proposed EPU, and requantifying the PRA to determine the CDF of the post-EPU plant.

<u>Initiating Event Frequencies.</u> The Waterford 3 PRA addresses LOCA, SGTR, and LOOP transients, loss of support systems, and ATWS.

LOCA initiators include small break (0.005 to 0.05 sq-ft), medium break (0.05 to 0.1 sq-ft), and large break (above 0.1 sq-ft) LOCAs. The licensee stated that the LOCA initiating event frequencies (IEFs) used in the PRA are generic values based on industry experience and expert judgment. Since deterministic analysis indicates that the loads and stresses on the RCS do not appreciably change for the post-EPU plant, the LOCA IEFs are not affected by the proposed EPU.

The SGTR IEF used in the Waterford 3 PRA is a generic value based on industry experience. The licensee stated that this generic IEF is applicable to Waterford 3 and remains so under the proposed EPU conditions. Since deterministic analysis indicates that the loads and stresses on the SG tubes do not appreciably change for the post-EPU plant, the SGTR IEF is not affected by the proposed EPU.

The licensee stated that Waterford 3 has never experienced a LOOP event. The LOOP IEF is based on a review of industry data collected by EPRI through 1999. The licensee excluded some of the industry experience as follows:

> All LOOP events related to snow and ice were discarded since the Waterford 3 site has a mild climate and no record of suffering extreme cold weather-related precipitation.
> All events related to hurricanes were discarded since site procedures require that Waterford 3 shut down to Mode 5 whenever a hurricane warning is issued, and arrival onsite is expected within 12 hours. The shutdown risk assessment considers hurricanes.
> Events clearly not relevant to Waterford 3 due to differences in plant design were discarded.

The LOOP IEF used in the Waterford 3 PRA, based on the above process, is 2.7×10^{-2}/year. By comparison, NUREG-1784 (Reference 64) estimated the industry-average LOOP IEF as 5.0×10^{-2}/year for the period 1985-1996, and 1.4×10^{-2}/year for the period 1997-2001.

Concerning the likelihood of a consequential LOOP, Reference 1 assessed the potential from grid instability as a result of the proposed EPU. Specifically, the transmission system in the vicinity of Waterford 3 was analyzed for single contingencies (loss of Waterford 3, loss of the largest generating unit, and loss of the most critical transmission line), crediting the rewound generator characteristics, to ensure that the grid system remains stable after the proposed EPU is implemented. Increasing the generation level does not result in instability of the Waterford 3 unit for the disturbances (faults or other single contingency events) expected on the transmission system. Offsite power systems will return to equilibrium without cascading trips of additional transmission lines, generators, or other transmission equipment after these disturbances. Additionally, during such disturbances, the offsite system will continue to supply the safety-related buses with acceptable voltage levels (per NEMA standards) so motors can start and perform their required safety function. Based on this analysis, the licensee has concluded that the likelihood of a consequential LOOP in the post-EPU plant is very small.

With respect to transient initiators, the licensee stated that the Waterford 3 RPS setpoint methodology assures that the trip setpoint values are sufficiently different from normal operating conditions to account for instrumentation uncertainties and drift. This methodology was used for all trip setpoints affected by power uprate, and the calculations demonstrated that the appropriate acceptance criteria for trip avoidance were met. The FW Control System (FWCS), Pressurizer Level Control System (PLCS) and SBCS setpoints were assessed and adjusted as necessary to ensure proper plant response to certain transients and plant maneuvers (load changes, heatup, and cooldown). The licensee discussed the hardware changes and setpoint modifications made to maintain margin on trip setpoints at the uprated power level and maintain equipment operation within design constraints. For example, the following changes (in addition to setpoint changes) were made to assure reliability of BOP systems:

- Replace high-pressure turbine steam path, replace main generator oil circuit breakers, rewind main generator (these ensure the turbine trip frequency is unaffected by power uprate).
- Replace selected FW heater level control valves as necessary (ensures that the loss of FW frequency is unaffected).

These modifications and setpoint changes mitigate the potential for increase of the frequency of transient initiators.

The licensee reviewed the support systems that may initiate a transient (e.g., DC power, AC power, CCW) for any changes in loads and requirements as a result of the proposed EPU, and verified that they will operate within their design capacities. Therefore, the IEFs of support system failures are not affected by the proposed EPU.

For ATWS events, the licensee stated that the sequence initiation would occur under the same primary system conditions as existed prior to the proposed EPU. Since there is no change in the transient IEFs, as discussed above, which is an input to calculating the ATWS event frequency, the licensee concluded that the potential for an ATWS event is also unchanged.

The licensee concluded that the proposed EPU will have no impact on the internal events PRA IEFs and, that stated, that future deviations in IEFs could be identified via existing monitoring processes such as licensee event reports (LERs), condition reports, and industry event databases. Also, safety system actuations are trended under the Maintenance Rule program as an indicator of unnecessary challenges to safety-related equipment.

The staff finds the licensee's assessment of the impact of the proposed EPU on IEFs acceptable, and concludes that the IEFs should not be noticeably impacted by the proposed EPU, as long as the operating ranges or limits of equipment are not exceeded. In addition, the staff notes that any changes in the IEFs following implementation of the proposed EPU would be identified and tracked under the licensee's existing performance monitoring programs and processes.

Component Failure Rates. The licensee stated that it performed comprehensive reviews of all plant systems and associated equipment with the potential to be affected by the proposed EPU, and that any changes in equipment service conditions and processes were identified in Reference 1. The licensee stated that modifications were made to ensure the performance of certain equipment and systems under EPU conditions to ensure that plant systems and equipment will continue to be operated within design constraints and that component failure rates will not change with the implementation of the EPU.

The licensee indicated that it will rely on existing component monitoring programs (e.g., preventive maintenance, vibration analysis, thermography, oil analysis, EQ, FAC, and the Maintenance Rule) to identify any additional wear as a result of the EPU. While the EPU may result in some components being refurbished or replaced more frequently, the licensee asserted that the functionality and reliability of components can be maintained to the current standard. These monitoring programs will also identify any future deviations in component failure rates.

The licensee concluded that the proposed EPU will have no adverse effect on component failure rates and that existing monitoring programs will be used to identify any future deviations in component failure rates.

The staff finds that it is reasonable to conclude that equipment reliability will not change, as long as the operating ranges or limits of the equipment are not exceeded. For equipment that is operated within its operating ranges or limits, the staff notes that the licensee's component monitoring programs, as identified above, should detect significant degradation in performance, and the staff expects these programs to maintain the current reliability of the equipment.

Accident Sequence Delineation. The licensee stated that it performed a detailed review to identify the effect of the EPU on the system success criteria credited in the Waterford 3 PRA model. Success criteria specify the requirements of the plant systems to address critical safety functions. These safety functions are as follows:

- Reactivity control
- RCS pressure control
- RCS pressure boundary integrity
- RCS and core heat removal
- RCS inventory control
- Long-term RCS inventory control and heat removal

The licensee performed thermal-hydraulic analyses using the CENTS code to confirm the success criteria for transient, SGTR, and the small end of the small LOCA sequences. The large LOCA and medium LOCA success criteria are based on the LOCA and ECCS licensing analyses. These analyses determined that there is no impact of the proposed EPU on the success criteria used in the PRA model.

The staff observes that the licensing basis thermal-hydraulic calculations indicate that the ADVs are required to mitigate a small LOCA, which differs from the PRA success criteria. When questioned about this apparent discrepancy, the licensee explained that the licensing basis thermal-hydraulic calculations include the conservatisms required by 10 CFR Part 50, Appendix K; specifically, the use of a 1.2 multiplier on decay heat. The staff agrees, noting that the third principle of the Commission's PRA policy statement (Reference 65) indicates that "PRA evaluations in support of regulatory decisions should be as realistic as practicable…"

The staff finds that it is reasonable to conclude that the proposed EPU will not change any success criteria used in the Waterford 3 PRA model because the licensee has re-evaluated the PRA success criteria using thermal-hydraulic modeling tools acceptable by the staff. Specifically, the staff accepted, in its letter dated December 1, 2003, the CENTS code (Reference 66) to calculate the transient behavior in PWRs designed by CE and by Westinghouse. Although CENTS should not be used for performing LOCA or severe accident licensing analyses (e.g., CENTS cannot be used to demonstrate compliance with 10 CFR 50.46 criteria), it is acceptable for modeling transients and small breaks in the primary system to be classified as LOCAs for the purpose of demonstrating compliance with non-LOCA regulatory acceptance criteria.

<u>Operator Actions and LOOP Recovery.</u> The licensee stated it performed a detailed assessment to determine the effects of the proposed EPU on the probabilities of human failure events (HFEs) and offsite power non-recovery. The proposed EPU has the general effect of reducing the time available for the plant operators to complete recovery actions because of the higher decay heat level after EPU implementation. Reduction in the time available to complete recovery actions can increase the probability of HFEs and offsite power non-recovery. The assessment involved the development of realistic, available times for post-accident HFEs and recovery of offsite power using the Waterford 3 CENTS model (and CEFLASH for small and medium LOCA) to simulate a variety of accident conditions. The CENTS and CEFLASH calculations were performed for uprated power levels. These calculations produced times for uncovering of core in a post-EPU condition, which were used to update the HRA and LOOP models. The licensee has noted that in some instances the post-EPU HFE probabilities are lower than the pre-EPU HFE probabilities because the pre-EPU time was based upon either conservative thermal-hydraulic analyses or engineering judgment. The following table shows the impact of the proposed EPU on the post-accident HFE available times and probabilities.

Impact of Proposed EPU on Post-Accident Human Failure Event Probabilities						
Event Name and Description	Pre-EPU		Post-EPU			
	Time Available	HFE Probability	Time Available	HFE Probability	Fussell -Vesely	RAW
EHFALPABMP Failure to energize bus 3AB-S from bus opposite initial supply	40 m	7.6 x 10^{-1}	2.83 m (Note 1)	1.0	N/A (Note 2)	N/A

Impact of Proposed EPU on Post-Accident Human Failure Event Probabilities						
Event Name and Description	Pre-EPU		Post-EPU			
	Time Available	HFE Probability	Time Available	HFE Probability	Fussell -Vesely	RAW
EHFALPABSP Failure to energize bus 3AB-S from bus opposite initial supply	60 m	1.1×10^{-1}	14 m	1.0	1.34×10^{-2}	1.01
EHFMANTRIP Failure to transfer loads to startup transformer when auto transfer fails	50 m	8.6×10^{-2}	68.3 m	3.2×10^{-2}	2.49×10^{-3}	1.61
EHFMTRLTP Failure to transfer load to startup transformer when auto transfer fails, with long time available	9 h	4.1×10^{-5}	14 h	4.1×10^{-5} (Note 3)	2.16×10^{-4} (Note 4)	2150
EHF-TEDG-P Failure to start/align/load TEDG	50 m	1.8×10^{-2}	68.3 m	5.8×10^{-3}	N/A (Note 5)	N/A
HHFALNABMP Failure to align HPSI pump AB to replace pump A or B following medium LOCA	40 m	4.4×10^{-1}	2.83 m (Note 1)	1.0	8.56×10^{-3}	1.0
HHFALNABSP Failure to align HPSI pump AB to replace pump A or B following small LOCA or SGTR	60 m	4.9×10^{-2}	14 m	1.0	4.00×10^{-3}	1.0
IHFSTCOMPP Failure to restart instrument air compressor after fast transfer failure	50 m	7.5×10^{-3}	68.3 m	1.0×10^{-3} (Note 6)	2.30×10^{-5}	1.0
NHFCDMKUPP Failure to make up to condenser hotwell from CSP when automatic makeup fails	50 m	3.9×10^{-2}	68.3 m	3.5×10^{-2}	N/A (Note 2)	N/A
OHFCONDSTP Failure to attempt to restore feed to SGs via condensate pumps	50 m	1.2×10^{-1}	68.3 m	7.5×10^{-3}	6.72×10^{-4} (Note 7)	323.7

Impact of Proposed EPU on Post-Accident Human Failure Event Probabilities						
Event Name and Description	Pre-EPU		Post-EPU			
	Time Available	HFE Probability	Time Available	HFE Probability	Fussell -Vesely	RAW
OHFRELTFWP Failure to attempt to restore FW (e.g., via auxiliary FW) after late loss of EFW	9 h	6.5×10^{-5}	14 h	1.0×10^{-5} (Note 3)	1.93×10^{-3} (Note 8)	18, 600
OHFRESTFWP Failure to attempt to restore FW (e.g., via auxiliary FW)	50 m	9.2×10^{-3}	68.3 m	1.8×10^{-3}	2.61×10^{-3}	2.45
PHFMFIVOPP Failure to unisolate MFW to allow feeding SGs after MSIS	50 m	1.4×10^{-2}	68.3 m	1.7×10^{-3}	1.82×10^{-4}	1,740
PHFSGTRBDP Failure to blow down SG to prevent overfilling affected generator	60 m	1.5×10^{-2}	>24 h	7.5×10^{-3}	8.94×10^{-4}	1.12
gQHFCSPEMPP Failure to align makeup to CSP during EFW operation	9 h	3.0×10^{-5}	9.33 h	3.0×10^{-5} (Note 3)	1.33×10^{-3} (Note 9)	18, 600 (Note 10)
QHFCSPWCTP Failure to align suction to EFW from WCT after CSP depletion	9 h	3.1×10^{-3}	14 h	3.1×10^{-3} (Note 3)	3.19×10^{-3}	18,600 (Note 11)
RHFSTCVCPP Failure to start charging pumps to provide backup injection following SGTR	60 m	1.1×10^{-3}	3 h (assumed)	5.1×10^{-4}	N/A (Note 2)	N/A

Notes:

1. The 2.83 minutes time available does not include the effect of the SITs, which would extend this time.
2. Not in cut sets.
3. HFE probability is based on cause-based calculation (not time-dependent); time-dependent probability is below 1×10^{-5} due to long time available.
4. In combination with QHFCSPEMPP and QHFCSPWCTP.
5. Temporary emergency diesel generator (TEDG) not used in EPU model; only applicable to Equipment Out of Service (EOOS) risk monitor for TEDG configuration.

6. Screening value of 1.0 was used.
7. In combination with QHFCSPEMPP and QHFCSPWCTP.
8. In combination with QHFCSPEMPP and QHFCSPWCTP.
9. In combination with QHFCSPWCTP.
10. In combination with QHFCSPWCTP and QHFRELTFWP
11. In combination with QHFCSPEMPP and QHFRELTFWP.

The preceding table also provides the Fussell-Vesely (FV) and risk achievement worth importance measures of the post-accident HFEs, as determined during the CDF quantification process. The licensee has stated that some of the HFEs are not independent; rather they are mutually dependent because they may be performed nearly simultaneously. As a result, the licensee replaces multiple dependent HFEs that appear in a single accident sequence cut set with a single combination HFE whose probability reflects the dependency. The individual HFE importance measures shown above use the maximum importance value for the HFE either individually or in a combination event. In cases where the importance value is taken from the combination event importance, the importance of the individual HFE within that combination may be overestimated.

The licensee noted that other HFEs appear in the PRA model. These HFEs include:

Pre-accident HFEs (e.g., "failure to restore after maintenance") that are not time-dependent and, thus, not affected by the EPU-related changes in sequence timing.
Post-initiator operator failures that did not change as a result of the EPU.

The licensee stated that the changes made to HFE probabilities have a very small effect on CDF. Specifically, these changes caused the CDF to decrease by about 3 x 10^{-9}/year. As previously discussed, the post-EPU HFE probabilities are based on realistic assessments of sequence timing, as compared to the conservative assessments and engineering judgment used in the pre-EPU PRA model. The licensee further stated that the major risk impact of the proposed EPU is due to changes in the LOOP non-recovery probabilities, which were calculated using the same thermal-hydraulic codes for both the pre-EPU and post-EPU plants.

If the licensee's submittal had been a risk-informed application, the staff would have required the licensee to perform additional thermal-hydraulic calculations to better determine the timings of operator actions in the pre-EPU plant, adjust the pre-EPU HFE probabilities, and recalculate the pre-EPU risk metrics to more accurately determine the change in CDF and the change in LERF due to the proposed EPU. However, since the licensee's submittal was not a risk-informed application, the staff's review of risk information was focused on identifying issues that could rebut the presumption of adequate protection provided by the licensee's meeting the currently-specified regulatory requirements. The staff believes that further resolution of this issue would not significantly alter the overall conclusions of this specific license amendment and, thus, would not rebut the presumption of adequate protection or warrant denial of this license amendment.

The licensee used the following approach to develop offsite power (OSP) non-recovery probabilities:

The set of generic LOOP events used to develop the LOOP IEF was reviewed, and each LOOP event was placed into one of three categories (plant-centered LOOP,

grid-related LOOP, or weather-related LOOP)
For each LOOP category, a Weibull probability distribution function was developed using maximum likelihood estimation.
An OSP recovery curve (which provides the probability that OSP is not recovered as a function of time after a LOOP) was formed from a weighted mixture of the Weibull probability distribution functions. The weights were based on the relative frequency at which each LOOP category appeared.

The staff observes that the approach used by the licensee to develop OSP recovery curves is the same as the approach used in NUREG-1032 (Reference 67), which is the technical basis of 10 CFR 50.63, the SBO Rule.

Reference 67 indicates that the duration of LOOP events has increased since 1997 (which is approximately the time when deregulation of the electric grid commenced). The licensee determined that the data used to form the Waterford 3 OSP recovery curves did not support the conclusion in Reference 67, and that it was therefore appropriate to use all events in the data as the basis for developing the OSP recovery curves. The licensee noted that there has never been a LOOP event at Waterford 3, and that deregulation proposals within the licensee's service area have been canceled or deferred as a result of problems with deregulation in other parts of the country.

The licensee stated that OSP recovery actions were modeled by appending OSP non-recovery events to the LOOP-initiated accident sequence cut sets. Several types of OSP non-recovery events were defined to account for the fact that a given accident sequence cut set may represent the failure of multiple plant components during their PRA-defined mission ("run failures"). The probability of each OSP non-recovery event was determined by defining and solving a convolution integral based on the product of the probability density functions associated with the run failures with the OSP recovery curve. The appropriate OSP non-recovery event was automatically appended to each LOOP-initiated cut set by the PRA solution software according to pre-defined rules.

At the staff's request, the licensee performed a study to assess the sensitivity of the post-EPU PRA results to the OSP non-recovery probabilities. The licensee stated that a 50 percent increase in the OSP non-recovery probabilities resulted in a 16 percent increase in CDF.

The staff finds that the changes made to the HFE and OSP non-recovery probabilities reasonably reflect the reductions in the times available for the operators to perform the necessary actions under post-EPU conditions because they are based on methodologies accepted by the staff in previous EPU applications.

Level 1 Internal Events Results. The internal events PRA model was requantified to assess the impact of the proposed EPU on internal event risk. The following table summarizes the results of the requantification.

Level 1 PRA Sequence Results					
Sequence	Description	Pre-EPU CDF	Post-EPU CDF	Change in CDF	% Change
ATWS	Anticipated transient without scram	1.35×10^{-7}	1.35×10^{-7}	0	0

Level 1 PRA Sequence Results					
Sequence	Description	Pre-EPU CDF	Post-EPU CDF	Change in CDF	% Change
AU	Large LOCA with SI failure in injection	1.96×10^{-8}	1.96×10^{-8}	0	0
AX	Large LOCA with SI failure in recirculation	1.57×10^{-9}	1.57×10^{-9}	0	0
ISLOCA	Interfacing system LOCA	3.13×10^{-7}	3.13×10^{-7}	0	0
MU	Medium LOCA with HPSI failure in injection	6.08×10^{-9}	6.08×10^{-9}	0	0
MX	Medium LOCA with HPSI failure in recirculation	1.32×10^{-7}	1.32×10^{-7}	0	0
RB	SGTR with failure of normal FW and EFW failure	1.77×10^{-8}	1.77×10^{-8}	0	0
RU	SGTR with failure of RCS injection	4.03×10^{-8}	4.03×10^{-8}	0	0
RX	SGTR with failure to depressurize	2.86×10^{-7}	2.86×10^{-7}	0	0
SB	Small LOCA with failure of normal feedwater and EFW failure	4.67×10^{-10}	4.67×10^{-10}	0	0
SBO	Station blackout with EFW AB failure or battery depletion	1.41×10^{-6}	1.65×10^{-6}	2.42×10^{-7}	4.4
SBORCP	Station blackout with RCP seal failure	0	1.08×10^{-10}	1.08×10^{-10}	0
SU	Small LOCA with HPSI failure in injection	9.76×10^{-8}	9.76×10^{-8}	0	0
SX	Small LOCA with HPSI failure in recirculation	1.61×10^{-7}	1.61×10^{-7}	0	0
TB	Loss of normal FW with EFW failure	2.56×10^{-6}	2.67×10^{-6}	1.06×10^{-7}	1.9
TPQB	Stuck-open SRV LOCA with failure of normal FW and EFW failure	5.49×10^{-10}	5.49×10^{-10}	0	0
TPQU	Stuck-open SRV LOCA with HPSI failure in injection	2.44×10^{-8}	2.44×10^{-8}	0	0
TPQX	Stuck-open SRV LOCA with HPSI failure in recirculation	3.95×10^{-8}	3.95×10^{-8}	0	0
TQB	RCP seal LOCA with failure of normal FW and EFW failure	1.04×10^{-9}	1.17×10^{-8}	1.35×10^{-9}	0.02
TQU	RCP seal failure with HPSI failure in injection	5.23×10^{-9}	5.23×10^{-9}	0	0
TQX	RCP seal failure with HPSI failure in recirculation	7.01×10^{-9}	7.21×10^{-9}	1.95×10^{-10}	0
V	RV rupture	2.70×10^{-7}	2.70×10^{-7}	0	0
TOTAL		5.52×10^{-6}	5.87×10^{-6}	3.5×10^{-7}	6.3

The staff finds that the licensee's evaluation of the impact of the proposed EPU on internal initiating event risk is reasonable because it is based on methodologies previously accepted by the staff for use in IPEs and EPU risk evaluations. Since the CDF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff concludes that the change in internal initiating event risk due to the proposed EPU is very small and that there are no issues concerning internal initiating events that rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements.

Level 1 Internal Flooding Risk Evaluation

The Waterford 3 IPE submittal used a conservative, progressive screening approach to assess the risk from internal floods. The application of this approach identified four unscreened flood scenarios that had a total CDF of 1.9×10^{-6}/year. The licensee reviewed the assessment of internal floods submitted in the IPE to determine the potential impact of the proposed EPU.

<u>Control Room.</u> The flood source, potable water pipes, is assumed to flood the control room (CR) envelope and to propagate and fill the lowest elevation of the RAB, including SI and EFW pumps (which is assumed to cause core damage without recoveries). The scenario includes three operator recoveries, none of which is affected by the proposed EPU: (1) isolation of the flood before equipment outside the CR is damaged (timing of the action is dependent on the flooding rate, which does not depend on reactor power), (2) replenishment of the EFW source (equivalent to events QHFCSPEMPP or QHFCSPWCTP in the internal events PRA model, whose probabilities are not affected by the proposed EPU), and (3) tripping the RCPs following loss of seal cooling (the time available to complete the action is dependent on the time to seal failure, which does not depend on reactor power).

<u>Control Room Emergency Living Quarters.</u> This scenario is similar to the CR flooding scenario previously described. The approximate CDF of this scenario was estimated at 2×10^{-10}/year, which is very small.

<u>RAB-31 (-4 elevation corridors and passageways).</u> This flood is assumed to fill the RAB to the +21 elevation (grade elevation), at which elevation the flood water would flow out of the RAB to the surroundings. An operator action is included to isolate the flood before the flood elevation reaches +21, thus sparing some essential equipment (e.g., switchgear) from flooding. The timing of this action is dependent on the flooding rate, which does not depend on reactor power.

<u>RAB-32 (-35 elevation pipe penetrations and ACCWS pumps).</u> This flood is also assumed to fill the RAB to the +21 elevation (grade elevation). An operator action is included to isolate the flood before the flood elevation reaches +21, thus sparing some essential equipment (e.g., switchgear) from flooding. The timing of this action is dependent on the flooding rate, which does not depend on reactor power.

The licensee reviewed plant design changes made since the IPE was conducted, and concluded that none of them affect the internal flooding analysis.

The staff finds that the licensee's evaluation of the impact of the proposed EPU on internal flooding risk is reasonable because it is based on a methodology previously accepted by the staff for use in IPEs and EPU risk evaluations. The staff concludes that there are no issues concerning internal floods that rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements.

Level 1 Internal Fire Risk Evaluation

The Waterford 3 IPEEE was performed using EPRI's Fire-Induced Vulnerability Evaluation (FIVE) methodology, which was updated to assess the impact of the proposed EPU on internal fire risk. In this method, for each fire area, a fire-initiating frequency was combined with a conditional core damage probability (CCDP) to determine the CDF. The CCDP for each fire area was calculated using a fire CDF model derived from the Level 1 internal events IPE model. This was accomplished by setting the basic events for all fire-susceptible equipment in the area to 'true' and solving the model. If the CDF obtained by combining this CCDP value with the area's fire-initiating frequency was less than 10^{-6}, then the area was screened from further analysis. Areas that did not screen on the first pass were evaluated using more realistic fire-initiator frequencies and fire damage scenarios. Since the CCDP is calculated using a model that is similar to the Level 1 internal events PSA, the IPEEE fire analysis attributes that could be affected by the proposed power uprate are the same as those for the Level 1 internal events PSA: initiating event frequencies, component failure rates, success criteria, operator actions, and LOOP recoveries. The licensee's assessment of the impact of the proposed EPU on each of these elements is:

The fire-initiating event frequency for each fire area is dictated by the combustible loading within the fire area and is, therefore, not affected by the proposed EPU.

There is no impact on component failure rates, which are used to determine the probabilities of random (i.e., non-fire-induced) failures, for the same reasons as stated in the internal events PRA assessment.

There is no impact on accident sequence success criteria, as discussed in the internal events PRA assessment.

Since the time available to perform operator actions may decrease with the increase in power, the operator recovery actions applied in the analysis may be affected. An available time of 50 minutes was used in the IPEEE fire analysis. However, recent CENTS calculations show that this time is 82.6 minutes before power uprate and that it is 68.3 minutes after power uprate. Since the fire risk is dominated by the unscreened areas, only the unscreened areas were evaluated for power uprate. The screened areas were treated very conservatively in the IPEEE fire analysis and, realistically, are much lower in risk than the unscreened areas. In this analysis, the CENTS-calculated available times were factored into the recoveries applied to the unscreened areas and new pre- and post-power uprate CDF values were calculated using the original IPEEE cut set files.

External LOOP is not assumed, since the initiator is a fire within the plant. LOOPs due to fire damage to offsite power-related cables and switchgear within the plant are included in the analysis, with no recovery credited. Therefore, the LOOP recovery (convolution) analysis described in the internal events section - which is dependent on available time - is not applicable to the fire analysis.

The impact of the proposed EPU on internal fire risk is shown in the following table.

Level 1 PRA Internal Fire Sequence Results					
Fire Area	Description	Pre-EPU CDF	Post-EPU CDF	Change in CDF	% Change
RAB 1A	Control room	1.95×10^{-6}	1.95×10^{-6}	0	0
RAB 1E	Cable spreading room	9.92×10^{-8}	9.92×10^{-8}	0	0
RAB 2	Heating & Ventilation (H&V) mechanical room	1.94×10^{-6}	1.94×10^{-6}	0	0
RAB 6	Electrical penetration area A	4.39×10^{-7}	4.39×10^{-7}	0	0
RAB 7	Relay room envelope	1.64×10^{-7}	1.64×10^{-7}	0	0
RAB 8	Switchgear room	1.48×10^{-6}	1.48×10^{-6}	0	0
RAB 15	EDG B	5.73×10^{-7}	5.73×10^{-7}	0	0
RAB 31	-4 corridor and passageways	5.58×10^{-8}	5.58×10^{-8}	0	0
RAB 39	-35 and –4 general areas	1.91×10^{-8}	1.92×10^{-8}	1.5×10^{-10}	1.8×10^{-3}
TGB	Turbine generator building	1.44×10^{-6}	1.44×10^{-6}	5.2×10^{-10}	6.4×10^{-3}
	TOTAL	8.15×10^{-6}	8.15×10^{-6}	6.7×10^{-10}	8.2×10^{-3}

The staff finds that the licensee’s evaluation of the impact of the proposed EPU on internal fire risk is reasonable because it is based on a methodology previously accepted by the staff for use in IPEEEs and EPU risk evaluations. Since the CDF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff concludes that the change in internal fire risk due to the proposed EPU is very small and that there are no issues concerning internal fires that rebut the presumption of adequate protection provided by the licensee’s meeting the currently specified regulatory requirements.

Level 1 Seismic Risk Evaluation

Waterford 3 was classified as a reduced scope plant in NUREG-1407, based on the low seismicity of its site. The IPEEE was performed by conducting a seismic margins analysis (SMA) of the safe shutdown equipment list (SSEL) with plant walkdowns in accordance with the guidelines and procedures in EPRI NP-6041-NL. The plant walkdowns did not identify any seismic outliers concerning operability issues. As a result, no seismic vulnerabilities were uncovered by the IPEEE.

The licensee stated that existing component monitoring programs will detect any additional wear as a result of the proposed EPU. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components will be maintained to the current standard. Thus, the increase in power level is not expected to affect equipment survivability nor equipment response during an earthquake. Also, the proposed EPU does not modify the safe shutdown pathway assumed in the SMA. Thus, the SMA results are not impacted by the power increase.

The staff finds that the licensee’s evaluation of the impact of the proposed EPU on seismic risk is reasonable because it is based on a methodology previously accepted by the staff for use in

IPEEEs and EPU risk evaluations. The staff concludes that there are no issues concerning earthquakes that rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements.

Level 1 Other External Events Risk Evaluation

The licensee used a progressive, conservative screening approach to assess the risks of other external events (high winds, external floods, and offsite industrial facility accidents). The focus of this part of the IPEEE submittal was on reviewing the plant design for consistency with the acceptance criteria in the 1975 SRP in terms of high winds, onsite storage of hazardous materials, and offsite developments. The original licensing action for Waterford 3 used the 1975 SRP as a basis for finding Waterford 3 acceptable in terms of external hazards with a few exceptions that the NRC reviewed and accepted. The exceptions were technical rather than substantive (e.g., the SRP-recommended technique for calculating tornado loading on the shield building was not appropriate given the shallow dome roof of the shield building). The IPEEE found no high winds, floods, or offsite industrial facility accidents that significantly altered the licensee's estimate of either the CDF, or the distribution of containment release categories. The IPEEE concluded that the plant is in conformance with the 1975 SRP that pertains to high winds, onsite storage of hazardous materials, and offsite developments.

The licensee stated that the proposed EPU only involves small impacts on internal event sequence timing. It does not affect high wind, flood, or offsite industrial accident frequencies, nor does it affect associated protective features, such as missile and flood barriers and toxic chemical monitors. Therefore, the proposed EPU has no impact on the risks associated with other external events.

The staff finds that the licensee's evaluation of the impact of the proposed EPU on other external event risk is reasonable because it is based on a methodology previously accepted by the staff for use in IPEEEs and EPU risk evaluations. The staff concludes that there are no issues concerning other external events that rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements.

Level 2 Internal and External Events Evaluation

A simplified, conservative method was used to estimate the impact of the proposed EPU on the LERF. This LERF calculation was a simplification of NUREG/CR-6595 (Reference 68). Four elements were considered:

- High Pressure (HP) core damage sequence leading to HP melt ejection/direct containment heating
- Core damage with failure of containment isolation
- Containment bypass sequences
- Thermally-induced SGTR

Note that several questions in the containment event tree were ignored in the present calculation, which is equivalent to not crediting the LERF-reducing effects of the phenomena under question. First, recovery after core damage but before vessel breach was ignored, i.e., no recovery was credited. Second, no credit is taken for sequence timing that could allow offsite protective actions before containment failure (i.e., to make a release late).

The impact of the proposed EPU on LERF associated with internal initiating events is shown in the following table.

LERF Sequence Results					
Sequence	Description	Pre-EPU LERF	Post-EPU LERF	Change in LERF	% Change
ATWS	Anticipated transient without scram	2.65×10^{-8}	2.65×10^{-8}	0	0
AU	Large LOCA with SI failure in injection	2.15×10^{-10}	2.15×10^{-10}	0	0
AX	Large LOCA with SI failure in recirculation	1.73×10^{-11}	1.73×10^{-11}	0	0
ISLOCA	Interfacing system LOCA	3.13×10^{-7}	3.13×10^{-7}	0	0
MU	Medium LOCA with HPSI failure in injection	6.69×10^{-11}	6.69×10^{-11}	0	0
MX	Medium LOCA with HPSI failure in recirculation	1.45×10^{-9}	1.45×10^{-9}	0	0
RB	SGTR with failure of normal FW and EFW failure	1.77×10^{-8}	1.77×10^{-8}	0	0
RU	SGTR with failure of RCS injection	4.03×10^{-8}	4.03×10^{-8}	0	0
RX	SGTR with failure to depressurize	2.86×10^{-7}	2.86×10^{-7}	0	0
SB	Small LOCA with failure of normal FW and EFW failure	9.14×10^{-11}	9.14×10^{-11}	0	0
SBO	Station blackout with EFW AB failure or battery depletion	2.76×10^{-7}	3.24×10^{-7}	4.73×10^{-8}	17.1
SBORCP	Station blackout with RCP seal failure	0	2.11×10^{-11}	2.11×10^{-11}	0
SU	Small LOCA with HPSI failure in injection	9.86×10^{-9}	9.86×10^{-9}	0	0
SX	Small LOCA with HPSI failure in recirculation	1.63×10^{-8}	1.63×10^{-8}	0	0
TB	Loss of normal FW with EFW failure	5.01×10^{-7}	5.22×10^{-7}	2.07×10^{-8}	4.1
TPQB	Stuck-open SRV LOCA with failure of normal FW and EFW failure	1.07×10^{-10}	1.07×10^{-10}	0	0
TPQU	Stuck-open SRV LOCA with HPSI failure in injection	2.46×10^{-9}	2.46×10^{-9}	0	0
TPQX	Stuck-open SRV LOCA with HPSI failure in recirculation	3.99×10^{-9}	3.99×10^{-9}	0	0
TQB	RCP seal LOCA with failure of normal FW and EFW failure	2.03×10^{-9}	2.30×10^{-9}	2.65×10^{-10}	13.1
TQU	RCP seal failure with HPSI failure in injection	5.28×10^{-10}	5.28×10^{-10}	0	0
TQX	RCP seal failure with HPSI failure in recirculation	7.08×10^{-10}	7.28×10^{-10}	1.97×10^{-11}	2.8
V	RV rupture	2.97×10^{-9}	2.97×10^{-9}	0	0
TOTAL		1.50×10^{-6}	1.57×10^{-6}	6.84×10^{-8}	4.6

For internal fires, the CDF increase for all unscreened fire areas was assumed to be totally high-pressure scenarios, producing a change in LERF of 7×10^{-11}/year.

The staff finds that the licensee's evaluation of the impact of the proposed EPU on LERF is reasonable because it is based on a methodology previously accepted by the staff for use in risk-informed submittals and EPU risk evaluations. Since the LERF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff concludes that the change in LERF due to the proposed EPU is very small and that there are no issues concerning containment performance that rebut the presumption of adequate protection provided by the licensee's meeting the currently specified regulatory requirements.

Shutdown Risk Evaluation

Shutdown risk impacts were examined in a qualitative manner by answering four questions posed by SRP 19 to determine whether impacts on shutdown risk would be important. The licensee's responses to these four questions follow:

1. Will these changes affect the shutdown schedule?

The SDCS performance evaluation indicates that the ability of the SDCS to achieve cold shutdown (less than 200 °F) in a reasonable time frame has been verified. The evaluation is comparable to that described in UFSAR Section 9.3.6 with consideration for the effects of the power uprate and system changes since the original evaluation. The SDCS remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS.

Since the decay heat levels are expected to be slightly higher at power uprate conditions, it may take a few hours longer to achieve cold shutdown. This will cause very little change in the shutdown schedule, and has no direct safety impacts on the schedule.

2. Will these changes affect operator ability to respond?

The following shutdown safety functions are typically tracked during an outage:

Decay heat removal

The SDCS performance evaluation notes that the SDCS remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS. Section 2.5.5.1 of the licensee's application notes that, with the increase in decay heat due to power uprate, the SFP temperature is still kept within allowable limits for a full-core discharge. The increase in temperature and the increase in decay heat will decrease the time for operators to respond to a loss of SDC or SFPC SDC or spent fuel pool cooling.

Maintaining an adequate defense-in-depth for this safety function, at all times, via the Shutdown Operations Protection Plan (SOPP), minimizes the impact of this decreased response time. The SOPP is prepared according to the guidance of the planned outages procedure. The current revision of this procedure includes requirements that:

> At least three of the following seven heat sinks shall be available: 2 wet cooling towers (WCTs), 2 dry cooling towers (DCTs), reactor head removed and refueling water level as

required by Technical Specification 3.9.8.1 (i.e., the large mass of water), or 2 SGs with associated RCPs.
Both SDC trains shall be available during reduced inventory operations.
Additional restrictions shall be in place when in reduced inventory conditions.

RCS inventory control

The increase in RCS temperature and the increase in decay heat will decrease the time for operators to respond to a loss of RCS inventory control. Maintaining an adequate defense-in-depth for this safety function, at all times, via the SOPP, minimizes the impact of this decreased response time. The SOPP is prepared according to the guidance of the planned outages procedure. The current revision of this procedure includes requirements that:

In addition to the SDCS requirements described above, 2 HPSI pumps with a flow path to the RCS are required during reduced inventory.
Mid-loop operations shall be minimized.

Vital power control (AC and DC)

The increase in RCS temperature and the increase in decay heat will decrease the time for operators to respond to a loss of electrical systems, since the electrical systems support the systems required for the other safety functions. Maintaining an adequate defense-in-depth of this safety function, at all times, via the SOPP, minimizes the impact of this decreased response time. For example, in addition to the requirements for the other safety functions, the current revision of the planned outages procedure includes the requirements that:

With an EDG out of service and two SDC trains required, 2 independent trains of offsite power are required. At least 1 EDG shall be operable.
For the protected train, the associated DC bus shall be energized and the 4160V AC safety bus shall be energized from offsite power with its EDG available. For the nonprotected train, if its associated SDC train is required, the associated DC bus shall be energized and the 4160V AC safety bus shall be energized from offsite power, i.e., work on the non-protected EDG is allowed. Waterford 3 currently performs major EDG maintenance on-line, so the unavailability of the EDGs during outage conditions when the non-protected SDC train is not affected by EPU.

Reactivity control

The non-LOCA safety analysis section of Reference 1 describes the uncontrolled boron dilution incident for power uprate conditions. The increase in rated power was found to have a negligible impact on the results of the boron dilution event. The analysis showed that for dilution during refueling, dilution during cold shutdown RCS filled, and dilution during cold shutdown with the RCS partially drained, the operator is alerted to the event with more than the minimum response time available.

Containment Closure

The containment closure safety function assures the capability to close the containment following a loss of another safety function. Thus, the response time for this safety function is decreased by the decreased response time for the other safety functions. Maintaining an adequate defense-in-depth for this safety function, at all times, via the SOPP, minimizes the impact of this decreased response time.

C Will changes affect shutdown equipment reliability?

As discussed previously, existing component monitoring programs can account for any additional wear as a result of power uprate. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standard.

C Will changes affect availability of equipment or instrumentation used for contingency plans?

As discussed previously, existing component monitoring programs can account for any additional wear as a result of power uprate. While the power uprate may result in some components being refurbished or replaced more frequently, the functionality and reliability of components can be maintained to the current standard.

The staff finds that the licensee’s qualitative assessment of shutdown risks associated with the proposed EPU is reasonable because it meets Section IV.4 of the SRP, Chapter 19. Specifically, the licensee has demonstrated that:

Suitably redundant and diverse plant response capability is maintained for significant initiators during shutdown modes, and
Sufficient elements of the plant response capability are subject to programmatic activities to ensure suitable performance.

Therefore, the staff concludes there are no issues concerning shutdown operations that rebut the presumption of adequate protection provided by the licensee’s meeting the currently specified regulatory requirements.

PRA Model Quality

The Waterford 3 PRA used to support the risk evaluation of the proposed EPU is an evolution of the IPE and IPEEEs developed by the licensee in response to GL 88-20. As requested in USNRC, “Individual Plant Examination: Submittal Guidance,” NUREG-1335, August 1989, an in-house peer review (including normal engineering and cross-discipline reviews) was performed prior to submitting the IPE and IPEEE to the staff; in addition, the IPE received a peer review by experts from a PRA consultant. The IPE was submitted to the staff on August 8, 1992; the staff replied on January 3, 1997 that the licensee’s IPE met the intent of GL 88-20. The IPEEE was submitted to the staff on July 28, 1995; the staff replied on July 27, 2000 that the IPEEE met the intent of GL 88-20.

Since its submittal to the staff, the PRA model has been updated several times to maintain it consistent with the as-built, as-operated plant. In January 2000, an owners group peer review of the PRA was conducted. The most recent PRA update, completed in June 2003, involved extensive revision of the human reliability analysis (HRA), common cause failure analysis, data analysis (generic and plant-specific failure rates and maintenance unavailabilities), and loss of offsite power analysis in order to address the staff's comments on the IPE and the comments generated by the owner's group peer review. All of the staff comments, with one exception, have been addressed. The exception pertains to the use of simulator exercises for in-control room operator response times and walkdowns for ex-control room response times. The licensee has stated that this comment no longer requires resolution since ASME RA-SA-2003, the ASME PRA Standard, Supporting Requirement HR-G5 identifies either walkthroughs, talkthroughs, or simulator exercises as acceptable bases for operator response times. While performing the latest PRA update, the licensee conducted operator talkthroughs of all post-accident operator actions addressed in the PRA.

In addition, the June 2003 PRA update resolved 16 of 19 A-level and 61 of 80 B-level peer review comments. The licensee has stated that weaknesses identified in the Level 2 IPE model are not applicable because the Level 2 model is not used in the EPU analysis; rather, a simplified, conservative method based on NUREG/CR-6595 is used, as described previously. Remaining open peer review comments include documentation and Level 2 comments, comments that are partially addressed, and minor model limitations; these open comments do not affect the ability of the model to estimate the risk impact of the proposed EPU.

Finally, as part of the June 2003 PRA update, engineering calculations were developed to document the development of all major elements of the initial and updated versions of the model. These calculations were independently reviewed and are retained by the licensee as quality records.

The staff has reviewed the outstanding A-level and B-level owners group peer review comments, and concurs with the licensee's assessment that they do not impact the results of the PRA. The staff finds that the licensee has met the intent of RG 1.174 (Sections 2.2.3 and 2.5), SRP Chapter 19 (Section III.2.2.4), and SRP Chapter 19.1, and that the Waterford 3 PRA has sufficient scope, level of detail, and technical adequacy to support the risk evaluation of the proposed EPU.

<u>Summary</u>

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

2.13.2 Additional Review Areas (Risk Evaluation)

The licensee submitted two additional license amendment requests that are required in support of the EPU submittal:

License Amendment Request NPF-38-250, October 22, 2003, Revision to Pressure/Temperature and Low Temperature Overpressure Protection Limits for 32 Effective Full Power Years
License Amendment Request NPF-38-252, December 19, 2003, Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen Monitors Using the Consolidated Line Item Improvement Process

The licensee did not identify either of these license amendment requests as "risk-informed," and did not submit any risk evaluations in support of them. The staff agrees that no risk evaluations of these related license amendment requests are necessary because:

NPF-38-250 is based on a deterministic analysis of the second reactor vessel surveillance capsule, which was removed from the core at 13.83 EFPY, as documented in WCAP-16088-NP.
NPF-38-252 is based on the Commission's approval of Technical Specification Travel Folder (TSTF)-447, as noticed in the Federal Register, 68 FR 55416, September 25, 2003. Specifically, hydrogen recombiners and hydrogen analyzers may be removed from TS controls since "The Commission has found that the hydrogen release from a design-basis LOCA is not risk-significant because the design-basis LOCA hydrogen release does not contribute to the conditional probability of a large release up to approximately 24 hours after the onset of core damage." Therefore, no risk evaluation of NPF-38-252 is necessary because the staff previously considered the generic risk implications of removing hydrogen recombiners and hydrogen analyzers from TS controls when approving TSTF-447.

Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

In order to achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for Waterford Steam Electric Station, Unit 3.

License page 4 Section 2.C.(1) - Maximum Power Level

The maximum reactor core power level will be changed from 3441Mwt to 3716Mwt. The License change reflects the actual proposed change in the plant and it is consistent with the results of the licensee's supporting safety analyses. The staff finds this proposed change acceptable.

Index Page IV

The Page number for “BORATED WATER SOURCES - OPERATING” under 3/4.1.2, “BORATION SYSTEMS” reflects the new page number this section is on. This is an administrative change.

Index Page VI

With the issuance of Amendment 195, dated June 16, 2004, and approval of the proposed change to delete the spray nozzle usage factors and related surveillance requirements, TS 3/4.8.2 will be completely deleted. The TS change reflects the deletion of TS 3/4.8.2 in the Index and is an administrative change. The staff finds this proposed change acceptable.

Index Page VIII

A new section, 3/4.7.1.7, on ATMOSPHERIC DUMP VALVES has been added in this amendment. This change is reflected on this page and is administrative in nature.

Index Page XV

This page lists Section 5.2 (CONTAINMENT) and 5.7 (COMPONENT CYCLIC OR TRANSIENT LIMITS). Section 5.2 is being deleted since the information is available in other licensee controlled documents. Section 5.7 is being deleted since transient logging requirements have been either relocated and/or deleted. The staff finds this proposed change acceptable.

Index Page XIX

Changing and addition of description of the figures and changing the corresponding page numbers in the index page are administrative in nature and therefore acceptable.

Index Page XXII

Changing the description of the tables in the index page to correspond with the table heading in the body of the TS is administrative in nature and therefore acceptable.

Index Page XXIII

Deletion and addition of description of the tables in the index page to correspond with the table heading in the body of the TS is administrative in nature and therefore acceptable.

Dose Equivalent I-131 (Page 1-3)

The licensee proposes to change the TS Section 1.10 definition of DE I-131 to be more consistent with the DBA dose analysis methodology, as revised in support of the EPU. The changes delete reference to dose conversion factors not used any longer in the licensee’s DBA dose analyses. The licensee’s revised definition refers to those dose conversion factors in the International Commission on Radiological Protection Publication 30 (ICRP-30), “Limits for Intakes of Radionuclides by Workers,” Supplement 1 to Part 1, tables titled “Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity.” The NRC staff finds acceptable the use of thyroid dose conversion factors based on ICRP-30 to calculate the DE I-131 value, as well as DBA dose analyses. This position is stated in Regulatory Information Summary RIS 2001-19, “Deficiencies in the Documentation of Design Basis Radiological Analyses Submitted in Conjunction with License Amendment Requests,” and RG 1.195, “Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-water Nuclear Power Reactors.”

TS 1.24 Rated Thermal Power (Page 1-6)

The rated core power level will be changed from 3441Mwt to 3716Mwt. The TS change reflects the actual proposed change in the plant and it is consistent with the results of the licensee’s supporting safety analyses. The staff finds this proposed change acceptable.

TABLE 2.2-1 Reactor Protective Instrumentation Setpoint Limits (Page 2-3)

In TS Table 2.2-1, “Reactor Protective Instrumentation Trip Setpoint Limits,” Functional Unit No.7, the “Steam Generator Pressure - Low” trip setpoint has been changed from $764 psia to $ 666 psia, and the allowable value has been changed from $749.9 psia to $ 652.4 psia.

The purpose of the low SG pressure reactor trip function is to assist the ESF system in a steamline break event. The reactor trip and main steam isolation functions are credited with limiting the consequences of the steamline break, FW line break with or without loss of AC power, and steam bypass malfunction events.

The low SG pressure setpoint is a variable setpoint. The setpoint is automatically set to a certain “step value” below actual SG pressure. As SG pressure increases, the variable trip setpoint is increased to maintain the adjusted step difference up to a calibrated maximum setpoint. At this point, further increases in SG pressure do not affect the trip/actuation setpoint. When SG pressure is decreasing, the setpoint must be manually reset. This is accomplished by manually depressing a reset button, which reduces the variable trip setpoint to a value equal to the current SG pressure minus the magnitude of the adjusted step value. This action can be repeated as necessary to preserve main steam isolation system protection while decreasing SG pressure during a shutdown. The setpoint calculation document (ECI92-019) indicated that during plant cooldown the low SG pressure trip setpoint can be manually decreased to 200 psi below the existing pressure. During plant startup the setpoint is automatically increased and remains 200 psi below SG pressure.

Since the low steam generator pressure trip/actuation setpoint is a variable setpoint that is automatically increased as SG pressure increases, an annunciator has been provided to alert the operator if the tracking function fails. This avoids the need for constant operator attention to the setpoint indicators to assure that the setpoint is tracking properly.

EC192-019 Section 7.7.2 contains detailed process measurement errors and instrument uncertainties. Section 7.7.3 contains the calculated trip setpoint and allowable value. The staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105 and therefore is acceptable.

TS 3/4.1.2.1 Boration Systems (Page 3/4 1-6)

SR 4.1.2.1a requires that the BAMT solution be monitored once per 24 hours to ensure it is above the minimum temperature limit whenever RAB air temperature is below a specified temperature. SR 4.1.2.1a is redundant to SR 4.1.2.7a, which also requires that the BAMT solution temperature be monitored once per 24 hours to ensure it is above the minimum temperature limit whenever RAB air temperature is below the specified temperature. TSs 3/4.1.2.1 and 3/4.1.2.7 are both applicable in Modes 5 and 6. The renumbering or rearranging of the remaining SRs in 4.1.2.1 to account for the deletion of SRs 4.1.2.1a is an editorial change and therefore acceptable.

TS 3/4.1.2.2 Flow Paths - Operating (Page 3/4 1-7)

The change to reference new figure 3.1-2 is an administrative change and is, therefore, acceptable.

SR 4.1.2.2a, which requires the same BAMT solution temperature monitoring, is redundant to existing SR 4.1.2.8b (new SR 4.1.2.8a). TSs 3/4.1.2.2 and 3/4.1.2.8 are both applicable in Modes 1, 2, 3, and 4. Therefore, the change to delete SRs 4.1.2.1a and 4.1.2.2a is an editorial change and is acceptable because it does not result in the elimination or reduction of any BAMT solution temperature monitoring requirements. The renumbering or rearranging of the remaining SRs in 4.1.2.2 to account for the deletion of SRs 4.1.2.2a is an editorial change and therefore acceptable. The change to reference new figure 3.1-2 is an editorial change and is, therefore, acceptable.

TS 3/4.1.2.7 Borated Water Sources – Shutdown (Page 3/4 1-12)

The licensee proposes to change Borated Water Sources – Shutdown by deleting the expression of boron concentrations in weight percent but retaining the expression of boron concentrations in ppm. The licensee also wishes to increase the minimum required boron concentration to 4900 ppm from the current minimum required value of 3950 ppm. There is no change proposed for the maximum required boron concentration, which is currently specified as 6125 ppm.

The staff agrees with the editorial changes, since they do not modify any safety limits. The staff also agrees with the increase in the minimum boron concentration requirement, since it supports the minimum shutdown margin requirements for natural circulation cooldown to the SDC entry conditions.

The change to increase the minimum required boric acid makeup tank solution temperature from 55 °F to 60 °F provides increased assurance that the solution will remain above the solubility limit (i.e., 50.2 °F) at the maximum allowed boric acid solution concentration when accounting for measurement uncertainty. Therefore, the staff finds this change acceptable.

TS 3/4.1.2.8 Borated Water Sources – Operating (Page 3/4 1-13)

The licensee proposes to change Borated Water Sources – Operating, TS 3/4.1.2.8, by replacing Figure 3.1-1 and adding Figure 3.1-2. Figure 3.1-1 would be replaced with a figure depicting the revised minimum boric acid concentration (4900 ppm), and the increase in Boric

Acid Makeup Tank (BAMT) minimum volume required when relying on one BAMT. New Figure 3.1-2 would be added to reflect the revised BAMT boron concentration and volume requirements when relying on two BAMTs.

The proposed increase in minimum required boron concentration, to 4900 ppm, is based upon an evaluation of the CVCS, which is described in Reference 1, Section 2.1.11, and the minimum shutdown margin requirements for natural circulation cooldown to the SDC entry conditions.

The change to increase the minimum required boric acid makeup tank solution temperature from 55 °F to 60 °F provides increased assurance that the solution will remain above the solubility limit (i.e., 50.2 °F) at the maximum allowed boric acid solution concentration when accounting for measurement uncertainty. Therefore, the staff finds this change acceptable.

The staff agrees to these changes in TS, since they're consistent with the increase in minimum required boron concentration.

TS 3.1.2.8b, applicable in Modes 1, 2, 3, and 4, specifies requirements for the refueling water storage pool that are redundant to the requirements specified in TS 3.5.4, also applicable on Modes 1, 2, 3, and 4. The staff finds these editorial changes acceptable since they do not modify any safety limits.

Fig. 3.1-1 Required Stored Boric Acid Volume As A Function of Concentration (Volume of One BAMT) (Page 3/4 1-14)

The evaluation is the same as for TS 3/4 1.2.8.

Fig. 3.1-2 Required Stored Boric Acid Volume As A Function of Concentration (Combined Volume of Two BAMT) (Page 3/4 1-14a)

The evaluation is the same as for TS 3/4 1.2.8.

TS 3/4.2.6 Reactor Coolant Cold Leg Temperature (Page 3/4 2-11)

The reactor coolant cold leg temperature range is changed from 541 °F - 558 °F to 536 °F - 549 °F. In addition, the temperature of 568 °F, which is allowed for 30 minutes after a power cutback, is changed to 559 °F. Reducing the cold leg temperature range increases thermal margin. The applicant has submitted relevant accident analyses, based upon the reduced initial cold leg temperature values, which indicate that the applicable acceptance criteria continue to be satisfied. Since these changes are consistent with the changes associated with the EPU and supported by the licensee's safety analyses for supporting the proposed EPU, the staff finds these proposed changes to the TSs acceptable.

TS 3/4.2.8 Pressurizer Pressure (Page 3/4 2-13)

The minimum pressurizer pressure value of 2025 psia is increased to 2125 psia. Since the increase in minimum pressurizer pressure is consistent with the changes associated with the EPU and supported by the licensee's safety analyses for supporting the proposed EPU, the staff finds this proposed change acceptable.

TABLE 3.3-4 Engineered Safety Features Actuation System Instrumentation Trip Values (Page 3/4 3-19)

In TS Table 3.3-4, “Engineered Safety Features Actuation System Instrumentation Trip Value” Functional Unit 4.b, the “Steam Generator Pressure - Low” trip setpoint has been changed from $764 psia to $666 psia and allowable value has been changed from $749.9 psia to $652.4 psia. The evaluation is the same as for TABLE 2.2-1.

TABLE 3.3-4 Engineered Safety Features Actuation System Instrumentation Trip Values (Page 3/4 3-20)

In TS Table 3.3-4, “Engineered Safety Features Actuation System Instrumentation Trip Value” Function Unit 7.e, the “Steam Generator (1&2) Pressure - Low” trip setpoint has been changed from $764 psia to $666 psia and the allowable value has been changed from $749.9 psia to $652.4 psia. The evaluation is the same as for TABLE 2.2-1.

TS 3/4.4.5.2.c Operational Leakage (Page 3/4 4-18)

The steam generator primary-to-secondary leakage rate of 1 gpm through all steam generators and 720 gallons per day through any one steam generator is reduced to 75 gallons per day primary-to-secondary leakage per steam generator. These leak rate reductions are made to provide margin for use in dose consequences analysis at EPU conditions. Since these changes are in the conservative direction, the staff finds them acceptable.

TS 3/4.4.8.2 Pressurizer Heatup/Cooldown (Page 3/4 4-33)

The following are deleted from Specification 3/4.4.8.2:

1. Requirement 3.4.8.2c regarding the maximum spray nozzle usage factor of 0.65.
2. Action statement b regarding requirements if the spray nozzle usage factor exceeds 0.65 and reference to Table 5.7-1.
3. Surveillance requirement 4.4.8.2.2 regarding determining every 12 hours that spray water differential temperature is within limits during auxiliary spray operation.
4. Surveillance requirement 4.4.8.2.3 regarding recording of spray cycles and corresponding water differential temperature when main spray is initiated with ΔT greater than 130 °F and when auxiliary spray is initiated with ΔT greater than 140 °F.

These deletions are being made because the requirements to which they pertain in TS Table 5.7-1 are being deleted. See the evaluation below for justification of the Table 5.7-1 deletions.

TS 3/4.5.1 Safety Injection Tanks (Page 3/4 5-1)

The proposed change will revise TS 3.5.1b to delete units of cubic feet for the contained borated volumes. Volume requirements will be stated only in terms of percent. Since the SIT level indications used by operations at Waterford 3 are in terms of percent level, the staff finds this proposed change practical and acceptable.

The maximum volume is changed from 83.8 percent to 77.8 percent. Since the results of LOCA analysis consistent with this proposed maximum SIT volume meets acceptance criteria of the event, the staff find this proposed change acceptable.

TS 3/4.5.4 Refueling Water Storage Pool (Page 3/4 5-9)

The licensee proposes to delete specification of the refueling water storage pool volume in gallons, i.e., the minimum required volume would be specified only as 83 percent, not 475,500 gallons. The licensee also proposes to clarify that “between 55 °F and 100 °F” means “greater than or equal to 55 °F and less than or equal to 100 °F”. These changes are editorial, not technical, in nature.

The staff agrees with the editorial changes, since they do not modify any safety limits.

TS 3/4.6.1.5 Containment Systems - Air Temperatures (Page 3/4 6-13)

The licensee proposes to replace the maximum containment air temperature of 120 EF with a temperature range of 90 EF to 120 EF. The action statement is revised to require the temperature to be restored within the required range if the air temperature is outside this range. A footnote is added to specify that this requirement applies in MODE 1 above 70 percent RTP.

The minimum temperature of this range, 90 EF, is used in the calculation of the minimum containment pressure used in the LOCA analyses which demonstrates that the criteria of 10 CFR 50.46 are satisfied (see Table 2.12-1 of Reference 1). Since 90 EF is used in a design basis analysis, inclusion in the TSs complies with 10 CFR 50.36 and the staff, therefore, finds this change acceptable.

TS 3/4.7.1.1 Turbine Cycle - Safety Valves (Page 3/4 7-1)

In the current TS, action statement “a” specifies that either the inoperable MS code safety valve be restored to operable or the linear power level - high trip setpoint be lowered as specified in Table 3.7-2 within four hours; otherwise, be in hot standby within six hours and cold shutdown within the following 30 hours. Action statement “a” will be revised to allow four hours to reduce power to the maximum allowable power as specified in Table 3.7-2 and to allow 12 hours to reset the linear power level-high trip setpoint as specified in Table 3.7-2. The shutdown statement is revised to be in hot standby within six hours and hot shutdown within 12 hours.

To allow 4 hours to reduce power level is a reasonable time for this action and is consistent with the standard TS in NUREG-1432. The revision to allow 12 hours for the reduction of the trip setpoint is less restrictive. However, this is a reasonable time period for lowering the trip setpoint, which has been reviewed and approved at other CE designed plants. To change the shutdown statement from cold shutdown within the following 30 hours to hot shutdowon within the following 12 hours is acceptable because the TS is only applicable in Modes 1, 2, and 3. Once the plant enters mode 4 (hot shutdown) the TS is no longer applicable and the action can be exited. Therefore, it is a neutral change.

TABLE 3.7.2 Maximum Allowable Power and Linear Power Level - High Trip Setpoint with Inoperable Steam Line Safety Valves (Page 3/4 7-3)

Table 3.7-2 will be revised to add a column specifying the maximum allowable power when MSSVs are out of service. This proposed change is consistent with the standard TS in NUREG-1432. The maximum allowable power levels listed in the table are adjusted downward from the analytical values to account for power measurement uncertainties. The linear power level - high trip setpoints are set 8 percent above the maximum allowable power level. This is reasonable and consistent with the approach used in the Standard TS in NUREG-1432. Based on the above evaluation, the staff find the proposed changes acceptable.

TS 3/4.7.1.3 Condensate Storage Pool (Page 3/4 7-6)

The licensee has included, as part of its EPU application, a request to make changes to TS 3.7.1.3. The requested change would modify TS 3.7.1.3 by increasing the minimum required contained water volume in the CSP from 91 percent to 92 percent, and by adding a requirement for water temperature to be greater than or equal to 55 EF and less than or equal to 100 EF. The proposed change also adds a new surveillance to existing Surveillance Requirement 4.7.1.3.1. The new surveillance requires that the CSP temperature be verified to be within the limits at least once per 24 hours when the indicated RAB air temperature is less than 55 EF or greater than 100 EF.

The licensee indicates in its justification that the reason for the requested increase in the minimum indicated CSP volume from 91 percent to 92 percent is to more accurately account for measurement uncertainty, but there is no change in the actual minimum required analytical limit used in the safety analysis. The indicated temperature range of 55 EF to 100 EF for the CSP is being proposed by the licensee because the pool water temperature is an input to various safety analyses. Analyses performed by the licensee for post-EPU operation that assume a CSP water temperature range of 50 EF to 100 EF demonstrated acceptable results. The 24-hour frequency that is proposed for verifying CSP water temperature when the RAB air temperature is less than 55 EF or greater than 100 EF is consistent with the frequency currently used for verifying the RWSP temperature in TS Section 3.5.4, “Reactor Water Storage.” Like the RWSP, the CSP is located in the auxiliary building and is protected from the direct effects of the outside atmospheric conditions.

The NRC staff has reviewed the licensee’s justification for the proposed changes to TS 3/4.7.1.3 and finds that the proposed change in minium indicated CSP volume is acceptable because it adds additional margin to account for measurement uncertainties, thereby assuring sufficient usable water inventory to cool the RCS to SDC entry conditions following a design basis accident consistent with the plant licensing basis. The staff also finds that the proposed requirement for CSP temperature and related surveillance are acceptable and appropriate because the CSP water temperature is used in the plant safety analyses; the proposed temperature range is within the bounds of the temperatures that are assumed in the plant safety analyses; and the surveillance requirement is consistent with a similar requirement that the NRC staff has previously found to be acceptable.

TS 3/4.7.1.5 Main Steam Line Isolation Valves (Page 3/4 7-9)

The proposed change will revise the full closure time of the main steam isolation valves from 4.0 seconds to 8.0 seconds. Since this proposed change is consistent with the assumption used in the safety analysis for supporting EPU, the staff finds this proposed change acceptable.

TS 3/4.7.1.6 Main Feedwater Isolation Valves (Page 3/4 7-9a)

The proposed change will revise the full closure time of the main feedwater isolation valves from 5.0 seconds to 6.0 seconds. Since this proposed change is consistent with the assumption used in the safety analysis for supporting EPU, the staff find this proposed change acceptable.

TS 3/4.7.1.7 Atmospheric Dump Valves (Page 3/4 7-9b)

A new TS, TS 3/4.7.1.7, that addresses ADV operability has been proposed.

The ADVs provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the MSIVs are closed or the condenser is not available. Waterford 3 has two ADVs, which are installed upstream of the MSIVs. The licensee stated that the ADVs were previously credited only for cooldown to SDC entry conditions and containment isolation. ADV operability for cooldown is presently addressed in Section 3/4.7.1.7 of the plant Technical Requirement Manual, while ADV operability for containment isolation is presently addressed in TS 3/4.6.3. For EPU operation, the ADVs are credited for SBLOCA mitigation at greater than 70 percent rated thermal power. The new TS 3/4.7.1.7 is being created to address the cooldown, SBLOCA mitigation, and containment isolation functions of the ADVs.

The licensee stated in Reference 1 that the existing ADV analog controllers are being replaced with more accurate digital controllers. According to 10 CFR Part 50 Appendix A, General Design Criterion 1, “Quality Standards and Records,” SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Additionally, 10 CFR 50.55a(h) requires that protection systems shall satisfy the criteria of the IEEE Standard 603-1991, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations,” and IEEE Standard 7-4.3.2-1993, “IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations.” Therefore, the staff questioned the digital controller’s qualification for the safety-related applications. By Reference 10, the licensee reversed its decision and stated that, as a result of the reanalysis of the post-EPU SBLOCA, digital ADV controllers will not be needed in support of EPU and, therefore, detailed responses to these questions (qualifications of the digital ADV controllers) will not be provided. Reference 10 reflects the withdrawal of the use of digital ADV controllers. Therefore, the issue of digital ADV controller application is closed.

The staff considers that using an analog ADV controller is acceptable because the component satisfies the existing TS requirements. The dump ADVs are containment isolation valves in a penetration flow path that is part of a closed system. The licensee proposes a 72-hour allowed outage time for these valves. This is consistent with Section 3.6.3 of the Standard TS for CE Plants, NUREG-1432.

The bases for this TS state that the ADVs must be capable of manual isolation. Reference 10 clarifies that this refers to both remote manual and local manual isolation. GDC 57 requires that closed system isolation valves must be capable of remote manual isolation. Therefore, the licensee's proposed TS complies with GDC 57 and is therefore acceptable with respect to isolation capability.

TS 3/4.8.1.1 and TS 3.8.1.2 A.C. Sources (Page 3/4 8-1 and Page 3/4 8-8)

The licensee has included in Reference 24 a request to make changes to TS 3.8.1.1 and TS 3.8.1.2. The proposed changes would (1) increase the minimum required fuel oil inventory to be maintained in each EDG fuel oil storage tank from 38,760 gallons to 39,300 gallons (useable volume); (2) revise the five day reduced fuel oil inventory requirement (allowed when replacement fuel oil is onsite within the first 48 hours) from a minimum required fuel oil inventory of 38,000 gallons to a minimum required fuel oil inventory of 37,000 gallons (usable volume); and (3) make a minor editorial change to add the word "and" at the end of TS 3.8.1.2.b.1 to be consistent with the wording used in TS 3.8.1.1.b.1.

At Waterford 3 there are two FOSTs (one for each EDG) with a maximum usable capacity of 40,747 gallons at overflow. Each FOST is required to supply sufficient fuel oil to its respective EDG for seven days of continuous operation following postulated accident conditions. Currently, the TSs require a minimum fuel oil inventory of 38,760 gallons to be maintained in each FOST based on plant operation at the current licensed power level (unconditioned TS requirement). The 38,760 gallons includes 760 gallons of unusable fuel oil and therefore provides only 38,000 gallons of fuel oil that are usable. This amount of fuel oil is sufficient for seven days of load dependent EDG operation, and is an exception to certain criteria of the ANSI Standard N195-1976, "Fuel Oil Systems for Standby Diesel Generators," as allowed by the NRC staff in Amendment 157 to the Waterford 3 UFSAR dated February 15, 2000. The current TS requirements also allow the EDG fuel oil inventory to fall below the seven day amount for a period not to exceed five days, provided replacement fuel oil is onsite within 48 hours and the fuel oil inventory does not fall below either of the amounts needed for five days based on full continuous loading or six days based on load dependent operation (conditioned TS requirement).

In order to satisfy the existing licensing-basis fuel oil inventory requirements for the EDGs following the proposed power uprate, the licensee proposed TS changes to require: (a) a minimum fuel oil inventory of 39,300 gallons, and (b) a minimum fuel oil inventory of 37,000 gallons for periods not to exceed five days when the 39,300 gallon requirement is not met and replacement fuel oil is onsite within 48 hours. Based on the results of confirmatory testing, the licensee has calculated the minimum required fuel oil inventory that is needed to operate the EDGs for seven days following the proposed power uprate to be 39,010 gallons for the "A" EDG and 39,037 for the "B" EDG; and calculated the inventory required for five days at full load to be 36,929 gallons. Also, the additional information provided in Reference 28 indicates that 37,000 gallons of fuel oil is adequate for load dependent EDG operation for over six-and-a-half days. Therefore, the proposed TS values of 39,300 gallons as the normal (unconditioned) fuel oil inventory requirement and 37,000 gallons as the lower (conditioned) fuel oil inventory requirement are consistent with the current plant licensing basis (includes exceptions that were allowed to ANSI N195-1976 referred to above). However, because the proposed increase in the unconditioned fuel oil inventory requirement leaves very little margin for operational flexibility, Reference 24 establishes a commitment to implement a design change to the onsite fuel oil storage system by December 31, 2006, that will accommodate a fuel oil storage volume equivalent to the fuel oil needed to run each EDG for seven days based on the calculational methods described in ANSI N195-1976. Also, because the proposed TS values (39,300 gallons and 37,000 gallons) are exclusive of instrument uncertainty, unusable tank volumes, and testing margin, the licensee has also committed to control and account for these items in site procedures and calculations.

Based on the information that was provided, the staff finds that the proposed TS changes to the EDG fuel oil inventory requirements are necessary for post-EPU operation in order to satisfy the existing EDG licensing basis. However, because the proposed fuel oil storage tank inventory requirements significantly reduce operational flexibility and are exclusive of instrument uncertainty, unusable tank volumes, and testing margin, the staff considers the licensee's commitments to: (a) install additional EDG fuel oil storage capacity by December 31, 2006, and (b) account for excluded items in site procedures and calculations, to be appropriate and necessary in order to restore operational flexibility and assure that excluded items are properly accounted for. Therefore, in consideration of the commitments that have been made, the staff considers the proposed changes to the EDG fuel oil storage requirements to be acceptable.

The proposed change to add the word "and" at the end of TS 3.8.1.2 b.1 in order to make it consistent with the wording used for TS 3.8.1.1.b.1 is editorial and, therefore, considered to be acceptable.

TS 5.2 Design Features, Containment (Page 5-1)

TS 5.2 lists some of the design features of the containment, as well as the design pressure and the design temperature. The licensee proposes to delete this TS. As justification, the licensee states that this specification contains information available in other licensee controlled documents. The staff has verified this for several of the items listed in TS 5.2.

The licensee's proposal is consistent with NUREG 1432, Volume1, Revision 3, which does not contain containment design features.

For these reasons the staff finds the deletion of Section 5.2 from the Waterford 3 TSs to be acceptable.

TS 5.7 COMPONENT CYCLIC OR TRANSIENT LIMITS (Page 5-6)
TABLE 5.7-1 (Page 5-7, 5-8, 5-9)

See the evaluation for Index Page XV.

TS 6.5 PROGRAMS (Page 6-7)

This TS change adds new Section 6.5.5, "Component Cyclic and Transient Monitoring," which is consistent with NUREG-1432. The new program addresses the Component Cyclic and Transient Monitoring requirements that have been relocated and is, therefore, acceptable.

TS 6.9.1.11.1 Core Operating Limits Report (Page 6-20a)

The applicant wishes to add the following references to the COLR, reference list:

“Technical Manual for the CENTS Code,” WCAP-15996-P-A (Methodology for Specification 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.3 for MTC, 3.1.3.1 for Movable Control Assemblies - CEA Position, 3.1.3.6 for Regulating and group P CEA Insertion Limits, and 3.2.3 for Azimuthal Power Tilt). (Since its acquisition of CE, Westinghouse has assigned Westinghouse designators to CE documents. In this case, “CENPD-282-P-A” is now known as “WCAP-15996-P-A.” There were no other changes to the document.)

“Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model,” CENPD-132, Supplement 4-P-A. (Methodology for Specification 3.1.1.3 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt and 3.2.7 for ASI).

These reports have been previously reviewed and accepted by the staff.

The staff agrees with this change in the Core Operating Limits Report, since it is administrative in nature, and does not affect or alter any safety limits.

4.0 REGULATORY COMMITMENTS

For amendment requests containing regulatory commitments, this section of the SE discusses the commitments and the staff's finding if the subject matter is adequately controlled by the licensee's administrative programs. Since the amendment includes numerous regulatory commitments, this section in the SE is used to tabulate the commitments and state the staff's finding regarding classification of the information as regulatory commitments.

The commitments are tabulated in a fashion similar to how it appears in the licensee's letters, starting from the application and subsequent supplements, chronologically. The numbering of the commitments, however, runs consecutively. Since the AST and EPU amendment requests have been linked, the AST submittals are included in the table. The licensee's supplement dated July 14, 2004, contained deletions and/or changes made in previous correspondence and these (and only these) are also tabulated here.

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

LIST OF COMMITMENTS

Reference letter dated 11-13-03, ADAMS Accession No. ML040260321

1. Control room dose for non-LOCA events under EPU conditions will be addressed based on the results of the GL 2003-01 required evaluation. Additionally, LOCA and FHA control room doses provided in this submittal will be reevaluated, as necessary, based on the results of the GL 2003-01 required evaluation.
   Licensee Commitment Number: A-26602
   Scheduled completion date: End of RFO13; Type: One-Time Action; Status: Closed by References 10, 14, 16, 20, and 22 via the AST amendment request.

2. With respect to Class 2 and 3 Code compliance, systems that fail to meet the current design requirements in their current configuration as a result of changes in input parameters will be redesigned and physically modified, as required to meet the current design requirements.
   Licensee Commitment Number: A-26603
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

3. To ensure that changes resulting from EPU do not cause excessive vibration that could be detrimental to system performance, vibration monitoring will be performed following EPU to identify sources of vibrations and appropriate corrective actions will be taken to eliminate or minimize these vibrations.
   Licensee Commitment Number: A-26604
   Scheduled completion date: In Cycle 14, Type: One-Time Action; Status: Open

4. Further analysis will be performed to ensure the electrical EQ equipment located inside containment will remain qualified.
   Licensee Commitment Number: A-26605
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Closed by the licensee's calculation EC-S90-014.

5. Plant modifications will be made as necessary to upgrade the main transformers to support EPU.
   Licensee Commitment Number: A-26606
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

6. An alkalizer skid will be added as part of the main generator rewind project to address main generator stator cooling water chemistry concerns.
   Licensee Commitment Number: A-26607
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

7. Due to the EPU, the existing breakers' continuous load and short circuit interrupting ratings will be exceeded, as well as the associated mechanical disconnect switches on either side of each breaker. New breakers and disconnects are required to meet 1333 MVA and will be installed over RFO12 and RFO13.
   Licensee Commitment Number: A-26608
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

8. The EPU also affects the ADV controllers. The existing ADV analog controllers are being replaced with more accurate digital controllers.
   Licensee Commitment Number: A-26609
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Closed since digital controllers are not used now (see Item 37 below).

9. However, because the EPU lowers steam generator and main steam operating pressures, the diverse emergency feedwater actuation signal (DEFAS) permissive setpoint will be lowered.
   Licensee Commitment Number: A-26610
   Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

10. The EPU configuration has been analyzed to a lower steam generator pressure. These PPS changes will be implemented for EPU.
    Licensee Commitment Number: A-26611
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

11. CPC constants will be updated to be consistent with the new definition of 100% power and other requirements of the EPU and cycle specific analysis.
    Licensee Commitment Number: A-26612
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

12. The EPU requires adjustments to NSSS control systems setpoints and parameters to provide proper control system performance for the EPU operating conditions.
    Licensee Commitment Number: A-26613
    Scheduled completion date: Power Ascension during Cycle 13; Type: One-Time Action; Status: Open

13. The COLSS constants that are based on the reactor thermal power and instrumentation uncertainties will be modified as necessary as part of the reload fuel design process. These constants will be calculated and implemented as part of the reload fuel design process.
    Licensee Commitment Number: A-26614
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

14. The EPU will employ the same measures that have been taken for existing valves to prevent missile generation.
    Licensee Commitment Number: A-26615
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

15. Based on this rule change to 10 CFR 50.44, Entergy will be submitting a separate license amendment request to eliminate the Waterford 3 technical specification requirements for combustible gas control in containment. This license amendment request will be submitted by the end of 2003.
    Licensee Commitment Number: A-26616
    Scheduled completion date: 12/31/03, Type: One-Time Action; Status: Closed. LAR was submitted on December 19, 2003, and the requested approval sent via Amendment No. 192, dated March 9, 2004.

16. In response to Generic Letter 2003-01, *Control Room Habitability*, Entergy has committed to complete the requested evaluation prior to the end of September 2004. This evaluation will include a validation of the inleakage assumptions made in the dose consequence analyses. The results of this evaluation will determine further appropriate actions, if any, that must be taken to resolve this issue. (Reference commitment A26565)
    Licensee Commitment Number: A-26617
    Scheduled completion date: 09/30/04, Type: One-Time Action; Status: Closed. See Reference 11.

17. These higher heat loads will increase the temperature of the CCWS return flow in some of the CCWS piping sections. The impact of these higher temperatures on the CCW piping, supports and components will be evaluated. Also, the impact of these higher temperatures on the shutdown cooling heat exchanger room cooler will be evaluated.
    Licensee Commitment Number: A-26618
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

18. In order to accept the higher MSSS flows for EPU, the HP turbine steam path will be replaced.
    Licensee Commitment Number: A-26619
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

19. The feedwater control system setpoints will be modified slightly to increase pump speed at a lower demand.
    Licensee Commitment Number: A-26620
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

20. The MSR safety valves are undersized for the EPU conditions and will be replaced as required.
    Licensee Commitment Number: A-26621
    Scheduled completion date: End of RFO13, Type: One-Time Action Status: Closed. Reference 10 deleted the need to replace the NSR SVs (See Item 38 below).

21. Measures will be implemented as necessary to prevent potential condenser tube vibration under power uprate conditions.
    Licensee Commitment Number: A-26622
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

22. Entergy will perform additional testing to reconfirm the acceptability of the fuel oil consumption rates utilized in the fuel oil usage calculation prior to implementing the EPU.
    Licensee Commitment Number: A-26623
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Closed by Reference 24.

23. Setpoints that are mentioned in emergency operating procedures or off normal procedures will be changed to new uprate values.
    Licensee Commitment Number: A-26624
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

24. The time window to establish simultaneous hot and cold leg injection in the LOCA emergency operating procedure will be changed from 2 and 4 hours to 2 and 3 hours.
    Licensee Commitment Number: A-26625
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

25. As discussed in Section 2.5.2.4, Entergy is submitting a separate license amendment request to eliminate the Technical Specification requirements for combustible gas control in containment. Resulting EOP changes, regarding operation of the combustible gas control system, will be made during the implementation phase following approval and issuance of the associated amendment.
    Licensee Commitment Number: A-26626
    Scheduled completion date: The scheduled completion date is changed by Item 39 below; Type: One-Time Action; Status: Open

26. Color banding will change for the following indicated parameters:
    a) Pressurizer pressure narrow range
    b) Pressurizer pressure wide range
    c) RCS cold leg temperature
    d) RCS hot leg temperature
    e) SIT levels
    Licensee Commitment Number: A-26627
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

27. Prior to EPU implementation, the simulator will be upgraded to provide operator training at EPU conditions.
    Licensee Commitment Number: A-26628
    Scheduled completion date: Beginning of last operator training cycle prior to RFO13 Type: One-Time Action; Status: Open

28. The training staff will provide training as determined by the Operations Training Review Group. Operators will receive training using the systematic approach to training process. This training will cover procedure changes, new or revised technical specifications / safety analysis, and equipment modifications for the EPU. The topics will include items such as high pressure turbine upgrade, new atmospheric dump valve controllers, and instrument range/alarm changes. Classroom training/testing and simulator training/testing with the new equipment/instrument changes installed will ensure the operators understand the changes to plant systems. Startup training will be conducted prior to the conclusion of the outage for the operations crews with emphasis on core reload, positive moderator temperature coefficient, reactor engineering interface, and teamwork skills.
    Licensee Commitment Number: A-26629
    Scheduled completion date: End of RFO13, Type: One-Time Action; Status: Open

29. The EPU simulator modification, design, analysis, and test data will be evaluated based on, but is not limited to, the following:
    a) Engineering report modification packages
    b) Design and analysis data including heat balance, balance-of-plant (BOP) flow changes, and plant systems set point changes
    c) Updated plant and physics data book
    d) Engineering reports on system response and new accident analyses
    e) Best-estimate data
    Licensee Commitment Number: A-26630
    Scheduled completion date: Beginning of last operator training cycle prior to RFO13
    Type: One-Time Action; Status: Open

30. The simulator will be compared to actual plant data.
    Licensee Commitment Number: A-26631
    Scheduled completion date: During Cycle 14, Type: One-Time Action; Status: Open

31. A Cycle 14 power ascension test program will be performed as described in Section 2.10.
    Licensee Commitment Number: A-26632
    Scheduled completion date: Startup after RFO13, Type: One-Time Action; Status: Open

<u>Reference letter dated 1-29-04, ADAMS Accession No. ML040340728</u>
None

<u>Reference letter dated 3-4-04, ADAMS Accession No. ML040690028</u>

32. The TS change provided to reduce the primary-to-secondary operational leakage limit in TS 3/4.5.2c from 720 gallons per day to 540 gallons per day will be revised to reduce the primary-to-secondary operational leakage to 150 gallons per day in agreement with NEI 97-06. The 1 gpm total primary-to-secondary operational leakage limit will also be changed accordingly. Due to the required administrative reviews for a TS change, this change will be provided in a future supplement to the EPU submittal to be submitted by the middle of July 2004.
    Licensee Commitment Number: A-26655
    Scheduled completion date: 07/15/04, Type: One-Time Action; Status: Closed by Reference 10.

<u>Reference letter dated 4-15-04, ADAMS Accession No. ML041110527</u>
None

<u>Reference letter dated 5-7-04, ADAMS Accession No. ML041330175</u>

33. As stated in Reference 1, Section 2.5.3.1, and Attachment 8, Entergy has committed to complete the evaluations of control room habitability in response to Generic Letter 2003-01 by September 30, 2004. This evaluation will include a validation of the inleakage assumptions made in dose consequence analyses. It is Entergy's intent to provide updated information on control room unfiltered inleakage and its impact on control room analyses in support of EPU. It is projected that additional information will be submitted to the NRC by June 30, 2004.

Licensee Commitment Number: A-26677
Scheduled completion date: 6/30/04, Type: One-Time Action; Status: Closed. By Reference 11, Entergy has decided to install an AST in the calculation of the accident doses to the control room personnel.

34. Entergy has therefore decided to withdraw its request to use this terminology [the word "indicated" and the phrase "an indicated"] in the technical specifications as requested in the November 13, 2003, submittal but will instead retain the information in the technical specification bases as described, for information only, in the November 13, 2003, submittal. Revised technical specification mark-ups reflecting this withdrawal will be submitted by July 15, 2004, in conjunction with the technical specification change committed to in the March 4, 2004, supplement regarding primary-to-secondary leakage.
Licensee Commitment Number: A-26678
Scheduled completion date: 7/15/04, Type: One-Time Action; Status: Closed. Reference 10.

<u>Reference letter dated 5-12-04, ADAMS Accession No. ML041380147</u>
None

<u>Reference letter dated 5-13-04, ADAMS Accession No. ML041360145</u>
None

<u>Reference letter dated 5-21-04, ADAMS Accession No. ML041460407</u>

35. In addition, due to recent issues regarding the EPU SBLOCA analysis (reference Entergy letter W3F1-2004-0035 to the NRC dated May 7, 2004 for further details), Waterford 3 no longer expects to need to install digital ADV controllers. The final determination regarding the need for digital controllers will be communicated to the NRC staff by July 15, 2004. If digital ADV controllers are to be used, a detailed response to this question will be provided at that time.
Licensee Commitment Number: A-26684
Scheduled completion date: 7/15/04, Type: One-Time Action; Status: Closed by Commitment No. 37 (see Reference 10).

<u>Reference letter dated 5-26-04, ADAMS Accession No. ML041490335</u>

36. Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components (i.e., MRP Reactor Vessel Internals Issues Task Group (ITG)). Entergy commits to continue its active participation in this MRP initiative to determine appropriate reactor vessel internals degradation management programs.
Licensee Commitment Number: A-26687
Scheduled completion date: Not Applicable; Type: Continuing Compliance; Status: Open

<u>Reference letter dated 7-14-04, ADAMS Accession No. ML042010150</u>
(NOTE: Only the changes from the November 13, 2003, application are listed here. Cross reference is provided for completion.)

37. Commitment 8 above, “The EPU also affects the ADV controllers. The existing ADV analog controllers are being replaced with more accurate digital controllers.” made in the 11/13/03 application, is being withdrawn.

    As a result of the reanalysis of the post-EPU SBLOCA, Entergy has determined that digital ADV controllers will not be needed in support of the EPU. The currently installed analog ADV controllers will be utilized for EPU with setpoint indications available on the plant monitoring computer.
    Status: Closed

38. Commitment 20 above,“The MSR safety valves are undersized for the EPU conditions and will be replaced as required.” made in the 11/13/03 application, is being withdrawn.

    The licensee has stated that since ongoing analysis indicates that MSR safety valve replacement is not necessary, Entergy will not be replacing the MSR safety valves for EPU and therefore withdraws this commitment.
    Status: Closed

39. In Commitment 25 above, the licensee stated that the necessary Emergency Operating Procedure (EOP) changes will be completed within 60 days of the NRC staffs approval of the license amendment request (LAR) to eliminate the hydrogen recombiners. The LAR to eliminate the hydrogen recombiners was approved by the staff as Amendment 192 on March 9, 2004. However; the necessary EOP changes to support EPU were not completed within 60 days. The commitment was rescheduled to be completed prior to the beginning of the last operator training cycle before the EPU is implemented.

    The scheduled completion date for Commitment 25, which was “60 days following issuance of combustible gas control amendment,” was changed to “Beginning of last operator training cycle prior to RFO13.”

40. As a result of the decision to continue to use the analog controllers on the ADVs, the following sentence in the Commitment number 28 (above) was changed to reflect the use of existing ADVs controllers.

    Existing:
    “The topics will include items such as high pressure turbine upgrade, new atmospheric dump valve controllers, and instrument range/alarm changes.”

    Revised:
    “The topics will include items such as high pressure turbine upgrade, atmospheric dump valve setpoint adjustment using indication from process monitoring computer, and instrument range/alarm changes.”

    This is as a result of #37 above.

<u>Reference letter dated 7-15-04, ADAMS Accession No. ML042020294 (AST)</u>

41. A second supplemental AST submittal will present calculated dose results for the following events:

a) Reactor Coolant Pump Seized Rotor / Sheared Shaft
b) Inadvertent Atmospheric Dump Valve Opening
c) Excess Main Steam Flow with Loss of Offsite Power
d) Letdown Line Break
Licensee Commitment Number: A-26717
Scheduled completion date: 8/8/04, Type: One-Time Action; Status: Closed by Reference 14.

Reference letter dated 7-28-04, ADAMS Accession No. ML042120475

42. Responses to the remainder of the questions [SRXB RAI] will be provided by August 10, 2004.
    Licensee Commitment Number: A-26708
    Scheduled completion date: 8/10/04, Type: One-Time Action; Status: Closed by supplement dated August 10, 2004.

43. The existing control loop will be modified such that the setpoint can be monitored on the plant monitoring computer. This connection to the nonsafety related plant monitoring computer will meet applicable isolation requirements.
    Licensee Commitment Number: A-26724
    Scheduled completion date: Implementation, Type: One-Time Action; Status: Open

44. Entergy Operations, Inc. (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components. Entergy commits to:
    a) continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,
    b) evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program, applicable to Waterford 3, and
    c) incorporate the resulting reactor vessel internals inspections into the Waterford 3 augmented inspection plan as appropriate and provide the internals inspection plan to the NRC staff for information.
    Licensee Commitment Number: A-26687
    Scheduled completion date: Not Applicable, Type: Continuing Compliance, until RV internals inspection plans are incorporated into the augmented inspection plan submitted to the NRC; Status: Open

Reference letter dated 8-10-04, ADAMS Accession No. ML042250177

45. The response to the final unanswered question (ie., #20) will be submitted by August 25, 2004.
    Licensee Commitment Number: A-26708
    Scheduled completion date: 8/25/04, Type: One-Time Action; Status: Closed by supplement dated August 25, 2004.

46. Ensure that the compensatory actions currently in place to protect the CCW design temperature at the outlet of the SDC heat exchanger are adequate, or revised as necessary, to accommodate the impact of the higher decay heat loads from EPU prior to

the implementation of the EPU. Maintain adequate compensatory actions in place until the final resolution (e.g., system rebate, etc.) is identified and implemented.
Licensee Commitment Number: A-26618
Scheduled completion date: Not Applicable, Type: One-Time Action; Status: Open

Reference letter dated 8-19-04, ADAMS Accession No. ML042360712 (AST)

47. Entergy will submit the results of its ongoing analyses for control room shine due to Large Break Loss of Coolant Accident (LOCA) by August 31, 2004.
Licensee Commitment Number: A-26717
Scheduled completion date: 8/31/04, Type: One-Time Action; Status: Closed by supplement dated September 1, 2004.

Reference letter dated 8-25-04, ADAMS Accession No. ML042440417

48. Revised technical specification mark-ups for technical specification pages 2-3, 3/4 3-19, and 3/4 3-20 [SG Pressure - low setpoint] will be provided in a future supplement to replace those previously provided.
Licensee Commitment Number: A-26732
Scheduled completion date: 9/30/04, Type: One-Time Action; Status: Closed by supplement dated November 4, 2004.

Reference letter dated 9-1-04, ADAMS Accession No. ML042470194 (AST)

49. Waterford 3 plant procedures will be revised to specify a maximum ESF leakage of half the value specified in LOCA radiological analyses consistent with RG 1.183.
Licensee Commitment Number: A-26738
Scheduled completion date: EPU/AST Implementation, Type: One-Time Action; Status: Open

Reference letter dated 9-14-04, ADAMS Accession No. ML042660243 (AST)

50. Entergy will update the FAC program with the revised heat balance and reassess the EPU impact on FAC prior to EPU implementation.
Licensee Commitment Number: A-26737
Scheduled completion date: EPU Implementation, Type: One-Time Action; Status: Open

Reference letter dated 10-08-04, ADAMS Accession No. ML042880327

51. Waterford 3 will monitor accessible branch connections off of the main steam and main feedwater lines, outside containment, for vibration. Accessible branch connections are those that do not require that scaffolding be built or insulation removed.

With respect to the main steam and main feedwater lines inside containment; there is one vent and two drains lines on each main feedwater line while each main steam line has branch lines associated with flow instrumentation and a vent line. In addition main steam line B has an additional drain line. These branch lines inside containment will not be monitored directly. Instead, these branch lines will be evaluated based on the vibration data obtained from the sensors installed on the main lines. If the vibration levels of the main lines do not increase significantly, it may be concluded that the same applies to the branch lines. Should vibrations in the main lines increase, analyses of the branch lines can be performed to deal with such increases.

As specified in the May 13, 2004 submittal, vibration monitoring and evaluation of measured data will be in accordance with ASME OM, Part 3, Operations and Maintenance of Nuclear Power - Plants.
Licensee Commitment Number: A-26744
Scheduled completion date: End of Cycle 13, Type: One-Time Action; Status: Open

Reference letter dated 10-08-04, ADAMS Accession No. ML042880418
None

Reference letter dated 10-13-04, ADAMS Accession No. ML0422890193 (AST)

52. Response 10:
Interpretation of RG 1.183 requirements on releases for SGTR was discussed at the August 12, 2004, meeting between Entergy and NRC. As a result of these discussions, Entergy agrees to revise the [SGTR] analysis as requested.
Response 11:
The weighting values will change as a result of the ongoing [SGTR] reanalysis (see Response 10) to fully account for early releases from the affected SG using both ADVs for the early rapid cooldown prior to isolation.
Response 12:
This information will be provided in conjunction with the information requested in Question 20.
Licensee Commitment Number: A-26745
Scheduled completion date: 10/22/04, Type: One-Time Action; Status: Closed Reference 22.

53. Response 23:
As discussed in the response to Question 24 below, Waterford 3 will revise the AST LBLOCA calculation to not credit fission product cleanup of Elemental Iodine due to Containment Spray for calculation of offsite and control room dose due to the containment air release pathway.
Response 24:
Waterford 3 will revise the calculation of AST LBLOCA offsite and control room dose due to the containment air release pathway to remove the credit for the scrubbing of elemental iodine by containment spray. As stated above, this is expected to have minimal (on order of 0.05 Rem TEDE to MCR) impact on results. Waterford 3 will submit the revised AST LBLOCA results to the NRC by October 22, 2004.
Licensee Commitment Number: A-26746
Scheduled completion date: 10/22/04, Type: One-Time Action; Status: Closed by Reference 22.

Reference letter dated 10-18-04, ADAMS Accession No. ML042940577
None

Reference letter dated 10-19-04, ADAMS Accession No. ML043010129 (AST)
None

Reference letter dated 10-21-04, ADAMS Accession No. ML043010238

54. The administrative controls [i.e., to limit the amount of assemblies that can be offloaded as a function of time after shutdown] will be maintained in site refueling procedures.
    Licensee Commitment Number: A-26754
    Scheduled completion date: Prior to moving spent fuel from the reactor core following EPU implementation, Type: Continuing Compliance; Status: Open

Reference letter dated 10-29-04, ADAMS Accession No. ML043080406

55. To improve the fuel oil storage capability and provide a larger operational band, Waterford 3 commits to a design change to the onsite fuel oil storage system that will accommodate fuel oil storage volume equivalent to the fuel oil needed to run each DG for seven days based on calculational methods described in American National Standards Institute (ANSI) Standard N195-1976, "Fuel Oil Systems for Standby Diesel Generators." The modification will be completed by December 31, 2006. Supporting TS changes will be submitted as needed to support changes.
    Licensee Commitment Number: A-26755
    Scheduled completion date: 12/31/06, Type: One-Time Action; Status: Open

56. The proposed Technical Specification (TS) values (39,300 and 37,000 gallons) are exclusive of instrument uncertainty, unusable tank volumes, and testing margin. These items will be controlled and accounted for in site procedures and calculations.
    Licensee Commitment Number: A-26756
    Scheduled completion date: EPU Implementation, Type: Continuing Compliance; Status: Open

Reference letter dated 10-29-04, ADAMS Accession No. ML043080403
None

Reference letter dated 11-04-04, ADAMS Accession No. ML043140283
None

Reference letter dated 11-08-04, ADAMS Accession No. ML043200122
None

Reference letter dated 11-16-04, ADAMS Accession No. ML043270472
None

Reference letter dated 11-19-04, ADAMS Accession No. ML043280359
None

Reference letter dated 1-14-05, ADAMS Accession No. ML050210054

57. Entergy commits to complete corrective actions to prevent the complete loss of feedwater upon the loss of two or more heater drain pumps prior to exceeding the current (i.e., pre-EPU) rated thermal Dower of 3441MWt.
    Scheduled completion date: Prior to exceeding 3441 MWt. Type: One-Time Action; Status: Open

<u>Reference letter dated 2-5-05, ADAMS Accession No. ML050400461</u>

58. Entergy Operations, Inc (Entergy) is currently an active participant in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) research initiatives on aging related degradation of reactor vessel internal components. Entergy commits to:

    a) continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,
    b) evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to Waterford 3,
    c) incorporate the resulting reactor vessel internals inspections into the Waterford 3 augmented inspection plan as appropriate.

    In addition, as requested by the NRC, a description of the program, including the inspection plan, will be submitted to the NRC for review and approval. The submittal date will be within 24 months after the final EPRI MRP recommendations are issued or within five years from the date of issuance of the uprated license, whichever comes first.
    Scheduled completion date: Within 24 months after the final EPRI MRP recommendations are issued or within five years from the date of issuance of the uprated license, whichever comes first. Type: One-Time Action; Status: Open

59. Prior to exceeding 3441 MWt, Entergy will submit, for NRC review and approval, a description of how Entergy accounts for instrument uncertainty for each Technical Specification parameter impacted by the Waterford 3 Extended Power Uprate.
    Scheduled completion date: Prior to exceeding 3441 MWt. Type: One-Time Action; Status: Open

60. The notification of the grid conditions between Entergy Transmission and Waterford 3, regarding grid conditions that could adversely impact Waterford 3 post-trip off-site voltage, will be formalized by 15 June 2005. The agreement will contain/address the following elements:
    Scheduled completion date: June 15, 2005. Type: One-Time Action; Status: Open

    a) Daily Model Load Flow studies (using off-line software such as PTI/PSSE (Power System Simulator for Engineering)) will be performed for the next day using daily cases representing that day of the month. If any transmission contingencies with respect to an element directly interconnected with the Waterford 230 kV switchyard occur during the day, the analyses will be updated.
       Type: Continuing Compliance - Until real time monitor is implemented; Status: Open
    b) Upon becoming aware that grid analyses (i.e., Load Flow analysis or real time contingency monitoring program when instituted) indicates unacceptable post-trip voltages for Waterford 3, Waterford 3 will be made aware of the postulated condition(s).

Type: Continuing Compliance; Status: Open

c) Subsequent to any Waterford 3 reactor trip, the resultant switchyard voltages will be verified to be bounded by the same voltages predicted by the Load Flow analysis program (or the real time contingency monitoring program when implemented) under the same conditions.
   Type: Continuing Compliance; Status: Open
d) If a real time contingency monitoring program is used to perform post-trip analysis considering specific voltage requirements of Waterford 3, the Transmission Operator will notify Waterford 3 when the program is unavailable or Waterford 3 will verify the that the program is available (at least weekly).
   Type: Continuing Compliance - Once real time monitor is implemented; Status: Open

Entergy is currently pursuing programming changes to the real-time contingency analysis software to perform post-trip analysis considering specific voltage requirements of Waterford 3. Entergy will update the NRC staff regarding the status/capabilities of the real time contingency monitoring program by 30 September 2005 following testing planned for the Summer of 2005.
   Scheduled completion date: September 30, 2005; Type: One time action; Status: Open

If the real time contingency monitoring program cannot be used to perform post-trip analysis considering specific voltage requirements of Waterford 3:

a) Entergy will obtain a motor manufacturer's endorsement or industry (e.g., industry expert) endorsement of Entergy's analysis results regarding proper operation of the Waterford 3 safety related motors (relied upon during the steam generator tube rupture event) subject to DV/DS conditions. The scenario shall be initiated at the setpoint of the degraded voltage relays.
b) This will be completed by October 20, 2006.
   Scheduled completion date: October 30, 2006; Type: One time action; Status: Open

If the real time contingency monitoring program is used to perform post-trip analysis considering specific voltage requirements of Waterford 3, upon becoming aware that the program is unavailable, Waterford 3 will perform an operability assessment of the offsite power sources.

   Type: Continuing Compliance - Once real time monitor is implemented; Status: Open

<u>Reference letter dated 2-16-05, ADAMS Accession No. ML050490396</u>
None

<u>Reference letter dated 3-17-05, ADAMS Accession No. ML050810095</u>
None

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff's review has identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU. These areas are recommended based on past experience with EPUs, the extent and unique nature of modifications necessary to implement the proposed EPU, and new conditions of operation necessary for the proposed EPU. They do not constitute inspection requirements, but are intended to give inspectors insight into important bases for approving the EPU.

a. Tests and experiments not described in UFSAR and changes to the facility or procedures as described in the UFSAR for power uprate were evaluated in accordance with 10 CFR 50.59 as appropriate. Example - control valves for the heater drain system.

b. Actions taken by the licensee to alleviate or prevent the effects of new or likely initiating events, in accordance with the license amendment or this SE, that were due to changes. Example - increased flow in primary systems including their interfacing systems.

c. Plant modifications for power uprate in accordance with licensing and design bases, licensee commitments, and the UFSAR. Example - The administrative controls that limit the amount of assemblies that can be offloaded as a function of time after shutdown and will be maintained in site refueling procedures.

d. Mitigating systems that initiate and perform their safety function in accordance with the time lines in new accident analyses, acceptance tests for plant modifications for power uprate, and applicable surveillance tests.

e. Individual components in mitigating systems that were altered or replaced can perform their intended safety function. Example - instrument and control changes.

f. That new operator actions (normal, abnormal, and emergency) for power uprate are administered procedurally and have an appropriate basis. Appropriate training should be provided to operators on the new procedures.

g. That the licensee monitors changes, in accordance with NRC SE, made on systems and their effects on those systems and interfacing systems including potential problems that are slow in developing and issues that could not be immediately tested (e.g., erosion corrosion or flow accelerated corrosion).

Inspection Procedure (IP) 71004, "Power Uprates," describes the inspections necessary for power uprate related activities and provides guidance for the inspectors to use in conducting these inspections. However, the recommendations here do not constitute inspection requirements, but are provided to give the inspectors insight into important bases the NRC staff used for approving the EPU.

6.0 STATE CONSULTATION

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

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on

October 12, 2004 (69 FR 60672). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received one comment, which was addressed in the final Environmental Assessment. The final Environmental Assessment was published in the Federal Register on April 4, 2005 (70 FR 17128). Accordingly, based upon the final Environmental Assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

By Reference 25, the licensee requested, pursuant to 10 CFR 50.90, approval of an amendment for Waterford 3, to revise the minimum fuel oil storage tank (FOST) volume included in Waterford 3 Technical Specifications (TS) 3.8.1.1 and 3.8.1.2. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding published December 7, 2004 (69 FR 70716). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

8.0 REFERENCES

Ref. No.	Subject
1	Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated November 13, 2003. Agencywide Documents Access and Management System (ADAMS) Accession Number ML040260321
2	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated January 29, 2004. Accession Number ML040340728
3	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated March 4, 2004. Accession Number ML040690028
4	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated April 15, 2004. Accession Number ML041110527
5	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated May 7, 2004. Accession Number ML041330175
6	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated May 12, 2004. Accession Number ML041380147

Ref. No.	Subject
7	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated May 13, 2004. Accession Number ML041380145
8	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated May 21, 2004. Accession Number ML041460407
9	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated May 26, 2004. Accession Number ML041490335
10	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated July 14, 2004. Accession Number ML042010150
11	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated July 15, 2004. Accession Number ML042020294
12	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated July 28, 2004. Accession Number ML042120475
13	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated August 10, 2004. Accession Number ML042250177
14	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated August 19, 2004. Accession Number ML042360712
15	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated August 25, 2004. Accession Number ML042440417
16	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated September 1, 2004. Accession Number ML042470194
17	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated September 14, 2004. Accession Number ML042660243
18	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 8, 2004. Accession Number ML042880327

Ref. No.	Subject
19	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 8, 2004. Accession Number ML042880418
20	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 13, 2004. Accession Number ML042890193
21	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 18, 2004. Accession Number ML042940577
22	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 19, 2004. Accession Number ML043010129
23	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 21, 2004. Accession Number ML043010238
24	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 29, 2004. Accession Number ML043080406
25	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated October 29, 2004. Accession Number ML043080403
26	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated November 4, 2004. Accession Number ML043140283
27	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated November 8, 2004. Accession Number ML043200122
28	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated November 16, 2004. Accession Number ML043270472
29	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated November 19, 2004. Accession Number ML043280359
30	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated January 5, 2005. Accession Number ML050100225
31	RS-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003.

Ref. No.	Subject
32	WCAP-16002-NP, Analysis of Capsule 263 from the Entergy Operations Waterford Unit 3 Reactor Vessel Radiation Surveillance Program, Revision 0, March 2003. (Submitted to the NRC by Entergy letter dated March 28, 2003.)
33	RG 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, March 2001.
34	RG 1.99, Revision 2, *Radiation Embrittlement of Reactor Vessel Materials*, May 1988
35	WCAP-14577, Revision 1-A, *License Renewal Evaluation: Aging Management for Reactor Internals,* March 2001.
36	BAW-2248A, *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals*, March 2000.
37	Entergy Operations, Inc., Letter No. W3F1-2003-0075 to the NRC Document Control Desk, *License Amendment Request NPF-38-250, Revision to Pressure/Temperature and Low Temperature Overpressure Protection Limits for 32 Effective Full Power Years, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38,* October 22, 2003 (ML041620063).
38	Topical Report CEN-367-A, *Leak Before Break Evaluation of Primary Coolant Piping in Combustion Engineering Designed Nuclear Steam Supply Systems*
39	EPRI NASC-202L, Revision 2, “Recommendations for an effective Flow Accelerated Corrosion Program.”
40	CENPD-187-P-A, *CEPAN Method of Analyzing Creep Collapse of Oval Cladding*, March 1976
41	EPRI NP-3966-CCM, *CEPAN Method of Analyzing Creep Collapse of Oval Cladding*, Volume 5, April 1985.
42	CEN-161(B)-P, Supplement 1-P-A, *Improvements to Fuel Evaluation Model*, Combustion Engineering, Inc., January 1992.
43	CENPD-139-P-A, *CE Fuel Evaluation Model Topical Report*, Combustion Engineering, Inc., July 1974.
44	CEN-161(B)-P-A, *Improvements to Fuel Evaluation Model*, August 1989.
45	CENPD-382-P-A, *Methodology for Core Designs Containing Erbium Burnable Absorbers*, ABB Combustion Engineering Nuclear Fuel, August 1993.
46	CEN-372-P-A, *Fuel Rod Maximum Allowable Gas Pressure*, ABB Combustion Engineering Nuclear Power, May 1990.
47	CENPD-161-P-A, TORC Code, *A Computer Code for Determining the Thermal Margin of a Reactor Core*, April 1986.

Ref. No.	Subject
48	CENPD-206-P-A, TORC Code, Verification and Simplified Modeling Methods, June 1981.
49	CENPD-162-P-A, *Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids, Part 1, Uniform Axial Power Distribution*, September 1976.
50	CENPD-207-P-A, *Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids, Part 2, Non-uniform Axial Power Distribution*, December 1984.
51	CEN-160(S)-P, Rev. 1-P, *CETOP Code Structure and Modeling Methods for San Onofre Nuclear Generating Station Units 2 and 3*, September 1981.
52	WCAP-14040A, Revision 4, “Methodology used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” Westinghouse Electric Company LLC, May 2004.
53	CENPD-137, Supplement 1-P, *Calculative Methods for the C-E Small Break LOCA Evaluation Model*, January 1977.
54	CENPD 282-P-A, *Technical Manual for the CENTS Code*, February 1991.
55	CENPD-188-A, *HERMITE, A Multi-Dimensional Space-Time Kinetics Code for PWR Transients*, March 1976.
56	CEN-191(B)-P, *CETOP-D Code Structure and Modeling Methods for Calvert Cliffs 1 and 2*, December 1981.
57	CENPD-135P, *STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program*, August 1974. CENPD-135P, Supplement 2, *STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program (Modifications)*, February 1975. CENPD-135, Supplement 4-P, *STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program*, August 1976.
58	CENPD-132, Supplement 3-P-A, *Calculative Methods for the C-E Large Break LOCA Evaluation Model for the Analysis of C-E and W Designed NSSS*, June 1985.
59	CENPD-137, Supplement 1-P, *Calculative Methods for the C-E Small Break LOCA Evaluation Model*, January 1977 (S1M).
60	CENPD-137, Supplement 2-P-A, *Calculative Methods for the ABB C-E Small Break LOCA Evaluation Model*, April 1998 (S2M).
61	CENPD-132, Supplement 4-P-A, *Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model*, March, 2001.
62	CENPD-254-P-A, *Post-LOCA Long Term Cooling Evaluation Model*, June 1980.

Ref. No.	Subject
63	Singhal, A. K. et al., *ATHOS3 Mod. 01: A Computer Program for Thermal-Hydraulic Analysis of Steam Generators, Volumes 1 - 3*, EPRI-NP-4604-CCML, September 1990.
64	USNRC, “Operating Experience Assessment - Effects of Grid Events on Nuclear Power Plant Performance,” NUREG-1784, December 2003.
65	USNRC, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Vol. 60, p. 42622 (60 FR 42622), August 16, 1995.
66	USNRC to Gordon Bishoff, Manager, Owners Group Program Management Office, Westinghouse Electric Company, “Final Safety Evaluation for Topical Report WCAP-15996-P, Technical Description Manual for the CENTS Code, (TAC No. MB6982),” December 1, 2003.
67	USNRC, “Evaluation of Station Blackout Accidents at Nuclear Power Plants,” NUREG-1032, June 1988.
68	BNL, “An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events,” NUREG/CR-6595, January 1999.
69	Not used.
70	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated January 14, 2005. Accession Number ML050210054
71	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated February 5, 2005. Accession Number ML050400461
72	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated February 16, 2005. Accession Number ML050490396
73	Waterford Steam Electric Station, Unit 3 (Waterford 3) - Issuance of Amendment re: Full-Scope Implementation of an Alternative Accident Source Term (TAC No. MC3789), dated March 29, 2005. Amendment Number 198
74	Memorandum from S. Jones to D. Thatcher, dated February 24, 2005, “Draft Safety Evaluation Input Regarding the License Amendment Request for Extended Power Uprate Power Ascension Testing for the Waterford Steam Electric Station Unit 3 (TAC No. MC1355)” (ML050540072)
75	Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 Docket No. 50-382 License No. NPF-38, Dated March 17, 2005. Accession Number ML050810095

9.0 CONCLUSION

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

Principal Contributors:

J. Medoff	R. Davis	J. Tsao	C. Wu	T. Scarbrough	N. Trehan
J. Lazevnick	H. Li	A. Stubbs	J. Tatum	N. Iqbal	R. Lobel
J. Raval	H. Walker	M. Hart	L. Brown	C. Liang	S. Miranda
F. Orr	L. Lois	W. Lyons	P. Clifford	L. Ward	J. Cai
S. Dennis	P. Prescott	M. Stutzke	N. Kalyanam		

Date: April 15, 2005

Attachment: Acronyms and Abbreviations used

Attachment

ACRONYMS & ABBREVIATIONS

10 CFR	Title 10 of the Code of Federal Regulations
AC	Alternating Current
ACCWS	Auxiliary Component Cooling Water System
ADAMS	Agencywide Documents Access and Management System
ADV	Atmospheric Dump Valve
AL	Analytical Limit
ANO-2	Arkansas Nuclear One, Unit 2
ANS	American Nuclear Standards
ANSI	American National Standards Institute
AOO	Anticipated Operational Occurrence
AOR	Analysis of Record
AOV	Air-operated Valve
ARI	All Rods In
ASGT	Asymmetric Steam Generator Transient
ASME	American Society of Mechanical Engineers
AST	Alternative Source Term
ASTM	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
AV	Allowable Values
B&PV	Boiler and Pressure Vessel Code
BAMT	Boric Acid Makeup Tank
BL	(NRC) Bulletin
BLPB	Branch Line Pipe break
BOC	Beginning of Cycle
BOP	Balance-of-Plant
BTP	Branch Technical Position

CAP	Containment Atmosphere Purge
CARS	Containment Atmosphere Release System
CASS	Cast Austenitic Stainless Steel
CCDP	Conditional Core Damage Probability
CCW	Component Cooling Water
CCWS	Component Cooling Water System
CDF	Core Damage Frequency
CE	Combustion Engineering, Inc.
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CEDMCS	Control Element Drive Mechanism Control System
CEDS	Control Element Drive System
CENPD	Combustion Engineering Nuclear Power Department
CESEC	Combustion Engineering System Excursion Code
CFR	Code of Federal Regulations
CFWS	Condensate and Feedwater System
CHLR	Closure Head Lift Rig
Code	ASME Boiler & Pressure Vessel Code
COLR	Core Operating Limits Report
COLSS	Core Operating Limits Supervisory System
CPC	Core Protection Calculator
CPCS	Core Protection Calculator System
CR	Control Room
CRH	Control Room Habitability
CS	Containment Spray
CSB	Core Support Barrel
CSS	Containment Spray System
CST	Condensate Storage Tank

CTM	Core Thermal Margin
CUF	Cumulative Usage Factor (fatigue)
CVCS	Chemical and Volume Control System
CWS	Circulating Water System
DBA	Design Basis Accident
DBE	Design Basis Event
DBLOCA	Design-Basis Loss-of-Coolant Accident
DC	Direct Current
DCT	Dry Cooling Tower
DEFAS	Diverse Emergency Feedwater Actuation Signal
DG	Draft Guide
DHR	Decay Heat Removal (synonymous with residual heat removal)
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
DSS	Diverse Scram System
EAB	Exclusion Area Boundary
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EFDS	Equipment and Floor Drainage System
EFPH	Effective Full-Power Hours
EFPY	Effective Full-Power Year
EFW	Emergency Feedwater
EFWS	Emergency Feedwater System
Entergy	Entergy Operations, Inc.
EOC	End of Cycle
EOL	End of Life
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute

EPU	Extended Power Uprate
EQ	Environmental Qualification
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
FAC	Flow-accelerated Corrosion
FES	Final Environmental Statement
FHA	Fuel-handling Accident
FHB	Fuel-Handling Building
FIV	Flow-Induced Vibration
FLECHT	Full Length Emergency Cooling Heat Transfer
FOST	Fuel Oil Storage and Transfer
FSAR	Final Safety Analysis Report
ft-lb	foot-pound
FV	Fussell-Vesely
FW	Feedwater
FWCS	Feedwater Control System
FWIV	Feedwater Isolation Valve
FWL	Feedwater Line
FWLB	Feedwater Line Break
FWP	Feedwater Pump
FWS	Feedwater System
GDC	General Design Criteria
GIS	Generated Iodine Spike
GL	(NRC) Generic Letter
GOTHIC	Generation of Thermal-Hydraulic Information for Containments
GWd/MTU	Gigawatt-Day per Metric Ton of Uranium
GWMS	Gaseous Waste Management System
H&V	Heating and Ventilation

HELB	High-Energy Line Break
HEPA	High-Efficiency Particulate Air (filter)
HDR	Heater Drain
HFE	Human Failure Event
HFP	Hot Full Power
HP	High Pressure
HPP	High-Pressurizer Pressure
HPSI	High-Pressure Safety Injection
HRA	Human Reliability Analysis
HTC	Heat Transfer Coefficient
HZP	Hot Zero Power
I&C	Instrumentation and Control
IASCC	Irradiation Assisted Stress Corrosion Cracking
ICI	In-core Instrumentation, In-core Instruments
ICSB	Instrumentation & Control System Branch
IEEE	Institute Of Electrical and Electronics Engineers
IEF	Initiating Event Frequency
IN	(NRC) Information Notice
IOSGADV	Inadvertent Opening of a Steam Generator Atmospheric Dump Valve
IPB	Iso-Phase Bus
IPE	Individual Plant Evaluation
IPEEE	Individual Plant Evaluation for External Event
ISA	Instrument Society of America
ISI	Inservice Inspection
kV	Kilo Volt
kW	Kilo Watt
LBB	Leak-before-break
LBLOCA	Large-Break Loss-of-Coolant Accident

LCO	Limiting Conditions for Operation
LDE	Dose to Eye Lens
LER	Licensee Event Report
LERF	Large Early Release Frequency
LHGR	Linear Heat Generation Rate
LHR	Linear Heat Rate
LOCA	Loss-of-Coolant Accident
LOCV	Loss of Condenser Vacuum
LOOP	Loss-of-Offsite Power
LP	Low Pressure
LPDES	Louisiana Pollutant Discharge Elimination System
LPSI	Low-Pressure Safety Injection
LPZ	Low-Population Zone
LSSS	Limiting Safety System Setting
LTC	Long-Term Cooling
LTOP	Low-Temperature Overpressure Protection
LWMS	Liquid Waste Management System
LWR	Light-Water Reactor
MBtu/hr	Million British Thermal Units per Hour
MC	Main Condenser
MCES	Main Condenser Evacuation System
MCL	Main Coolant Loop
MCLB	Main Coolant Loop Break
MeV	Mega Electron Volts
MEDP	Maximum Expected Differential Pressure
MFIV	Main Feedwater Isolation Valve
MFP	Main Feedwater Pump
MFW	Main Feedwater

MNSA	Mechanical Nozzle Seal Assembly
MOV	Motor-Operated Valve
mrad	millirad
mrem	millirem
MS	Main Steam
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
MSLB	Main Steam Line Break
MSR	Moisture Separator Reheater
MSSS	Main Steam Supply System
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
MVA	Megavolt-Amperes
MVAR	Megavolt-Amperes Reactives
MTU	Metric Ton Uranium
MWD/MTU	Megawatt-Day per Metric Ton of Uranium
MWt	Megawatts Thermal
NAI	Numerical Applications, Incorporated
NDE	Nondestructive Testing
NEI	Nuclear Energy Institute
NEM	Nodal Expansion Difference Solution
NEMA	National Electric Manufacturer's Association
NERC	North American Electric Reliability Council
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System

NUMARC	Nuclear Management and Resources Council
NUREG	U.S. Nuclear Regulatory Commission Document
OBE	Operating Basis Earthquake
OPM	Overpower Margin
PASS	Post-Accident Sampling System
PCT	Peak Cladding Temperature
PD	Pump Discharge
PIS	Pre-existing Iodine Spike
PLCEA	Part-Length Control Element Assembly
PLCS	Pressurizer Level Control System
PLHR	Peak Linear Heat Rate
PMC	Plant Monitoring Computer
PMT	Post-Modification Test
PPCS	Pressurizer Pressure Control System
PPS	Plant Protection System
PRA	Probabilistic Risk Assessment
PRT	Pressurizer Relief Tank
PSA	Probabilistic Safety Analysis
PSB	Power System Branch
psi	Pounds per Square Inch
psia	Pounds per Square Inch, absolute
psig	Pounds per Square Inch, gauge
PSV	Pressurizer Safety Valve
P-T	Pressure-Temperature
PTS	Pressurized Thermal Shock
PU	Power Upgrade
PUR	Power Uprate Report
PWR	Pressurized Water Reactor

PWSCC	Pressurized Water Stress Corrosion Cracking
QA	Quality Assurance
QSPDS	Qualified Safety Parameter Display System
RAB	Reactor Auxiliary Building
RAI	Request for Additional Information
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RF	Refueling Outage
RG	Regulatory Guide
RHR	Residual Heat Removal (synonymous with decay heat removal)
RPC	Reactor Power Cutback
RPCS	Reactor Power Cutback System
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RPVI	Reactor Pressure Vessel Internals
RRS	Reactor Regulating System
RS	Review Standard
RSB	Reactor Systems Branch
RT_{PTS}	Reference Temperature - Presssurized Thermal Shock
RTP	Rated Thermal Power
RT_{PTS}	Reference Temperature-Pressurized Thermal Shock
RV	Reactor Vessel
RVI	Reactor Vessel Internal
RWSP	Refueling Water Storage Pool
S2M	Supplement 2 Model
SAF	Single Action Failure
SAFDL	Specified Acceptable Fuel Design Limit

SAR	Safety Analysis Report
SBCS	Steam Bypass Control System
SBLOCA	Small-Break Loss-of-Coolant Accident
SBO	Station Blackout
SBS	Steam Bypass System
SBVS	Shield Building Ventilation System
SCC	Stress Corrosion Cracking
scfm	Standard Cubic Feet per Minute
SCU	Statistical Combination of Uncertainties
SDCL	Shutdown Cooling Line
SDCF	Skin Dose Conversion Factor
SDCS	Shutdown Cooling System
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SFPCC	Spent Fuel Pool Cooling and Cleanup
SG	Steam Generator
SGBS	Steam Generator Blowdown System
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIAS	Safety injection actuation signal
SIS	Safety Injection System
SIT	Safety Injection Tank
SL	Safety Limit
SLB	Steam Line Break
SMA	Seismic Margins Analysis
SOPP	Shutdown Operations Protection Plan
SPDS	Safety Parameter Display System
SRP	Standard Review Plan

SRV	Safety Relief Valve
SSC	Structure, System, and Component
SSE	Safe Shutdown Earthquake
SSEL	Safe Shutdown Equipment List
SUPS	Static Uninterruptible Power Supplies
SUT	Startup Transformer
TAD	Time of Annulus Downflow
TAM	Thermal Anchor Movement
TAVS	Turbine Area Ventilation System
TBCCWS	Turbine Building Closed Cooling Water System
TBS	Turbine Bypass System
TEDE	Total Effective Dose Equivalent
TEDG	Temporary Emergency Diesel Generator
TGSS	Turbine Gland Sealing System
TLU	Total Loop Uncertainty
TODE	Total Organ Dose Equivalent
TRM	Technical Requirements Manual
TS	Technical Specification
TSP	Trip Setpoint
UGS	Upper Guide Structure
UHS	Ultimate Heat Sink
USE	Upper Shelf Energy
v/o	Volume Percent
VOPT	Variable Overpower Trip
Waterford 3	Waterford Steam Electric Station, Unit 3
WCT	Wet Cooling Tower
Westinghouse	Westinghouse Electric Company, LLC
w/o	Weight percent

cc:

Mr. Michael E. Henry, State Liaison Officer
Department of Environmental Quality
Permits Division
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

Vice President Operations Support
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286-1995

Director
Nuclear Safety Assurance
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Wise, Carter, Child & Caraway
P. O. Box 651
Jackson, MS 39205

General Manager Plant Operations
Waterford 3 SES
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Licensing Manager
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Winston & Strawn
1400 L Street, N.W.
Washington, DC 20005-3502

Resident Inspector/Waterford NPS
P. O. Box 822
Killona, LA 70066-0751

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011

Parish President Council
St. Charles Parish
P. O. Box 302
Hahnville, LA 70057

Executive Vice President
& Chief Operating Officer
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286-1995

Chairman
Louisiana Public Services Commission
P. O. Box 91154
Baton Rouge, LA 70825-1697