Attachment 5

FPL Energy Point Beach, LLC
Point Beach Nuclear Plant Units 1 and 2

License Amendment Request 261
Extended Power Uprate

Licensing Report

1497 Pages Follow

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1.0 INTRODUCTION TO THE POINT BEACH NUCLEAR PLANT UNITS 1 AND 2 EXTENDED POWER UPRATE LICENSING REPORT

General Overview of the PBNP Extended Power Uprate (EPU) Licensing Report

The FPLE Point Beach, LLC (PBNP) EPU Licensing Report (LR) is a technical summary of the results of the analyses and evaluations performed to demonstrate that the proposed increase in thermal power can be safely achieved and that the increase will not be inimical to the common defense and security or to the health and safety of the public.

The LR is an attachment to license amendment request 261. The LR provides the details that support the requested License and Technical Specification changes. It works in concert with the other attachments to the amendment request to provide a comprehensive evaluation of the effects of the proposed EPU.

The fundamental outcome of the PBNP evaluations have been formatted and documented in accordance with the template and criteria provided in RS-001, Review Standard for Extended Power Uprates, Revision 0. The role of the LR is to document the technical basis for the evaluation of the effects of the proposed changes necessary to implement EPU with a sufficient level of detail to permit the NRC staff to reach an informed decision regarding the consistency, quality and completeness of the evaluation. Attention has been paid to ensure that the technical evaluations presented in the LR include, when appropriate, discussion of the effects of EPU on plant operating limits, functional performance requirements and design margins, as well as describing the methods PBNP used in reaching the conclusions documented in the report consistent with the guidance of RS-001. To enhance the efficiency of the NRC review, PBNP has included Appendix C, Scope and Associated Technical Review Guidance, that identifies the differences between the information in the review standard and the design and licensing bases of PBNP.

PBNP used RS-001 to the extent possible and added information to the LR that is specific to a good understanding of the effects of EPU on PBNP, as appropriate. Accordingly, the factors considered salient to the understanding of the LR are described below. In addition, the EPU license amendment request (LAR) is supported by two previously submitted LARs; LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, dated November 25, 2008 (ML083330160) and PBNP LAR 241, Alternative Source Term, dated December 8, 2008 (ML083450683).

Plant Description

The two nuclear units designated as PBNP Units 1 and 2 are located in east central Wisconsin (Manitowoc County) on the west shore of Lake Michigan about 30 miles SE of Green Bay and about 90 miles NNE of Milwaukee. The Units 1 and 2 reactors are Westinghouse designed, pressurized light water moderated and cooled systems. Each unit was originally licensed at a rated core thermal power output of 1518.5 MWt. Each steam and power conversion system, including its turbine generator, was originally designed to permit generation of 523.8 MW of gross electrical power. PBNP Units 1 and 2 began commercial operation in December 1970 and October 1972, respectively. In 1983, PBNP replaced the Model 44 steam generators in Unit 1 with Westinghouse Model 44F steam generators. In 1996, PBNP installed the Westinghouse Model Δ47 steam generators to replace the Model 44s in Unit 2. Each unit has undergone a low pressure turbine retrofit modification which increases the unit design output to 538 MWt gross. In 2003, a measurement uncertainty recapture power uprate was performed, increasing each unit's rated thermal power level to 1540 MWt.

Schedule

Initial modifications necessary to allow operation at the Extended Power Uprate (EPU) conditions (Refer to Table 1.0-1, Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications) were implemented during the Fall 2008 refueling outage for Unit 1. Additional modifications will be implemented before or during the Spring 2010 refueling outage for Unit 1 and the Fall 2009 and Spring 2011 refueling outages for Unit 2. The necessary modifications (Table 1.0-1, Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications, Category A) required to support the EPU safety analyses will be implemented prior to power ascension above the current licensed rated thermal power (RTP) power level. Power Ascension to the EPU power level is planned following approval of LAR 261 as described in LR Section 2.12, Power Ascension and Testing Plan. As described in LR Section 2.12, Power Ascension and Testing Plan, power will be increased above the current licensed power level in a slow and deliberate manner, stopping at pre-determined power levels for steady-state data gathering and formal parameter evaluation.

Plant Modifications

Table 1.0-1, Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications, provides a listing of the major plant physical modifications required to support operation at the uprate power level. The following discussion highlights the principal design and modification changes associated with the EPU but does not address all modifications listed on Table 1.0-1.

Ginna has successfully achieved an uprate to 1775 MWt, 25 MWt less than the proposed EPU core power level for PBNP. PBNP and Ginna are both two-loop Westinghouse Nuclear Steam Supply System (NSSS) plants. A comparison of the significant NSSS design parameters for the uprated PBNP and Ginna is provided in Table 1.0-2, Comparison of PBNP and Ginna NSSS Design Parameters.

Fuel/Reactor Core Design

The uprated core will operate at a licensed core thermal power of 1800 MWt as compared to the current rated core thermal power of 1540 MWt. This represents an increase of approximately 16.9 % in core thermal power. No change in the fuel assembly design is required nor proposed for EPU. The core operating limits will continue to be established using NRC-approved methodologies, and all fuel design constraints will continue to be satisfied. Several setpoints for the reactor trip system and the engineering safety features actuation system will be revised.

Reactor Coolant System

There are no physical modifications planned to the reactor coolant system or reactor vessel internals.

The reactor coolant system operating temperatures will change for the uprate. The operating reactor coolant average temperature at 1800 MWt core power will be increased from 570°F to 576°F. The reactor coolant temperature increase across the core will increase in proportion to the increase in uprated power. With the higher core average temperature increase, the reactor outlet temperature (T_{hot}) will increase, and reactor inlet temperature (T_{cold}) will decrease. The reactor coolant system no-load temperature will remain at the current value of 547°F.

The design of the pressurizer heater control system currently actuates the backup heaters and provides an alarm on a high level deviation signal. As part of the safety analyses at EPU conditions, the pressurizer backup heater actuation on pressurizer high level deviation signal will be removed. The current alarm on the pressurizer high level deviation will be retained.

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with high measured T_{avg}. The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off and letdown isolation occurs while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions. Analyses described in LR Section 2.4.2.2, Pressurizer Control Component Sizing, and LR Section 2.8.5, Accident and Transient Analyses, determined the nominal pressurizer level program for EPU must be changed from the current 20%-45.8% program to a new nominal program of 20% at no load conditions to 29.9%-47% for a full power T_{avg} of 558°F to 577°F.

Reactor Protection System - LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems

RPS instrumentation and setpoint changes necessary to ensure the RPS will continue to satisfy its design functions at EPU conditions are described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. Some of these Technical Specifications setpoint changes were identified as being less restrictive than the corresponding calculated values in October 2005. These setpoints will be revised as part of this License Amendment Request.

Engineered Safety Features Actuation System (ESFAS)

ESFAS instrumentation and setpoint changes necessary to ensure the engineered safeguards system will continue to satisfy its design functions at EPU conditions are described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. Some of these Technical Specifications setpoint changes were identified as being less restrictive than the corresponding calculated values in October 2005. These setpoints will be revised as part of this License Amendment Request.

Steam Generator (LR Section 2.2.2.5)

The best estimate steam generator steam pressure for the uprate will be approximately 802 psia (Unit 1) and 806 psia (Unit 2) due to the increase in the operating reactor coolant operating T_{avg} to 576°F. The main steam flow from the steam generators will increase to accommodate the higher required turbine flow at EPU conditions. The steam generator moisture separator packages will be modified to maintain the steam moisture content below 0.25%.

Main Steam (LR Section 2.5.5.1)

The results of the Loss of Load and Turbine Trip analyses documented in LR Section 2.8.5.2.1, Loss of External Load, Turbine Trip, Loss of Condenser Vaccum, demonstrate that the secondary pressure limits are met at the proposed EPU conditions. The nominal lift settings of the Main Steam Safety Valves with the two highest setpoints will be lowered on each steam generator.

Due to higher main steam flows at EPU conditions, the Main Steam Isolation valves (MSIVs) internals will be upgraded to address flow-induced vibration and closure loads. The main steam non-return check valves, located downstream of the isolation valves, are of similar design and the internals will also be modified.

Main steam pipe support modifications are required to mitigate the larger flow induced fluid transient loads that resulted due to EPU conditions (LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports).

Main Turbine (LR Section 2.5.1.2.2)

The Units 1 and 2 high pressure turbines steam paths will be replaced in order to pass the additional volumetric steam flow. The turbine control valves and inlet piping will be modified to accommodate the increase in steam flow and resultant increased pressure drop from the steam generators. The low pressure turbines will not be modified as they are capable of passing the higher volumetric flow rate.

Condensate and Feedwater (LR Section 2.5.5.4)

The condensate and feedwater flow rates will increase at the uprate power conditions. The condensate pumps and main feedwater pumps (MFPs) will be replaced with pumps with higher rated flow and total developed head (TDH) to accommodate the increased required feedwater flow and increased system pressure drops. As a result, the condensate and feedwater pump motors will be replaced with motors at higher rated horsepower. The feedwater minimum flow recirculation line size will also be increased due to the higher flow capacity feedwater pumps.

In addition, the feedwater regulating valves (FRVs) will be modified with new valve trim having a higher flow coefficient (Cv) and new actuator to accommodate the increased feedwater flow and available pressure drop for flow control.

Due to the increase in operating flows and pressures of the condensate, feedwater, heater drains and extraction steam systems, all feedwater heaters will be replaced. Associated Heater Drain piping and valves will also require modifications to address the new FW heaters and EPU conditions.

To minimize mass and energy releases inside the Containment following a main steam line break (MSLB), new Feedwater Isolation Valves (FIVs) are being installed in the main feedwater lines going to the steam generators.

Feedwater pipe support modifications are required to mitigate the larger flow induced fluid transient loads that resulted due to EPU conditions (LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports).

Higher condensate pump flow rate and additional head loss in the condensate and feedwater piping will result in lower suction pressure at the main Feedwater Pumps (MFP). To preserve operating margin to alarms and automatic actions on low MFP suction pressure, the setpoints associated with MFP low suction header pressure protection and low pressure feedwater heater bypass will be lowered.

Auxiliary Feedwater (AFW) (LR Section 2.5.4.5)

The AFW System will be modified prior to the EPU implementation. Two higher capacity Motor Driven (MD) pumps and their associated 4160 Volt, 350 Hp motors will be installed to meet the higher, EPU flow requirement. In addition, the new MDAFW pumps will be unitized rather than being shared between the two units. After the modifications are completed, one new 100% capacity MDAFW pump will provide flow to both SGs in Unit 1 and the other new 100% capacity MDAFW pump will serve the Unit 2 SGs. In addition, the flow control scheme for the MDAFW trains will be revised. The original design had a pressure control valve at the pump discharge. As part of the EPU modification, the pressure control valve will be eliminated and a flow control valve will be added on each of the two individual SG flow paths from each new MDAFW pump.

The existing two shared MDAFW pumps will be maintained as standby and startup pumps. During the normal plant stratup the existing MDAFW will be used and available as the manually started backup pumps during non design basis accident events.

The EPU required AFW flow is well within the rated capacity of the existing Turbine Driven (TD) pump system. As part of the EPU implementation, the setpoint on the throttle valves in the individual SG flow paths from the TDAFW pump will be adjusted to accommodate increased AFW flow. With these modifications, each unit will have one 100% capacity unitized MDAFW pump system in addition to the existing 100% capacity unitized TD pump system.

To enhance the AFW system reliability, the switchover of the AFW pumps from the non-seismic Condensate Storage Tank source to the safety-related, seismic Service Water source will be changed to an automatic function. This will remove the current operator manual actions required to effectthe switchover.

The unitized configuration, revised flow control and automatic switchover modifications enhance the system capability to deliver the required AFW during plant transients with no immediate operator actions.

Main Generator (LR Section 2.3.3)

The main generator electrical output for each unit will increase by approximately 85 MWe. Each main generator will be modified to increase the rated output from 582 MVA to a minimum of 684 MVA with an allowable power factor of 0.94.

The hydrogen and exciter air coolers will be replaced and additional cooling will be provided to the coolers to accommodate the increased cooling loads.

New 19kV Main generator breakers are being installed prior to the EPU to improve the electrical system margins and to accommodate the EPU increased electrical loads. The new main generator circuit breaker additions and 4160 kV bus transfer scheme modifications improve the performance of the safety-related 4160 kV and 480V systems. The safety-related system will experience improved voltage levels and lower short circuit currents with these modifications.

Iso-Phase Bus Ducts/Main Transformers (LR Section 2.3.3)

To transfer the power from the main generator to the grid, the design capacity of the iso-phase bus duct system will be increased. The bus duct cooling fan/coil capacity will be increased to provide additional cooling.

The three single phase main transformers on both units will be replaced with transformers rated 225 MVA each to accommodate plant output at EPU conditions.

345kV System (LR Section 2.3.2)

The new 19 kV main generator output breakers, provided for use when generator trips are required, allow the existing 345 kV main generator breakers to remain closed to feed auxiliary power to the plant's AC auxiliary system via the Unit Auxiliary Transformers after a generator trip.

Transmission Grid (LR Section 2.3.2, Offsite Power System)

The grid loading and stability analysis determined that voltage levels and breaker duty remain adequate after the implementation of the EPU. However, there are thermal and stability limits that will be exceeded by the implementation of the PBNP EPU. These issues can be resolved by a combination of breaker protection improvements, installation of a switching station, line segment upgrades, and operating restrictions. The proposed timeline to complete the 345 kV system upgrades will be after the implementation of the PBNP EPU. Interim upgrades will be implemented by PBNP and American Transmission Company (ATC) to allow PBNP to operate at EPU conditions prior to the completion of all of the required system upgrades.

Risk Evaluation (LR Section 2.13)

To reduce the overall core damage frequency (CDF) and large early release frequency (LERF) values following implementation of the EPU, the following plant modifications will be installed in conjunction with EPU:

- Provide a backup compressed gas supply for the Pressurizer Auxiliary Spray Valve CV-296 inside containment on each Unit.
- Provide an increased air supply to the motor-driven AFW pump mini-recirculation valves and flow control valves.
- Install a self-cooled (i.e., air-cooled) air compressor to supply Instrument Air independent of Service Water cooling and aligned for automatic operation.

Table 1.0-1
Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications

#	Modification	Category (A, B, C)(1)	Install Under 10 CFR 50.59	LR Section
1	NSSS instrument, setpoints, settings and scaling modifications (including MSSV setpoints)	A	No	2.4.1/2.8.5
2	Addition of Main Feedwater Isolation Valves	A	Yes	2.5.5.4
3	Auxiliary Feedwater System modifications (including new MDAFW pumps, flow control valves, auto switchover to SW and CST level setpoints)	A	Yes(3)	2.5.4.5
4	Alternate Source Term (AST) modifications (LAR 241)(2)	A	No(2)	2.9.2
5	HP Turbine Upgrade (including control valve and inlet piping changes) and gland seal	B	Yes	2.5.1.2.2 2.5.3.3
6	Steam Generator Moisture Separator modifications	A	Yes	2.2.2.5
7	Main Steam Isolation Valve upgrade	A	Yes	2.5.5.1
8	Condensate and Feedwater Pump and Motor Replacement (including feedwater recirculation line size change)	B	Yes	2.5.5.4
9	Feedwater Regulating Valve Trim and Operator change	B	Yes	2.5.5.4
10	Feedwater Heater replacements	B	Yes	2.5.5.4
11	Heater Drain Piping and Valves modifications (including tank level controls and alarms)	B	Yes	2.5.5.4
12	Main Steam and Feedwater Pipe support modifications	A	Yes	2.2.2.2
13	BOP Instruments, Setpoints, Settings, Scaling	B	Yes	2.4.1
14	Main Generator Rewind Modifications (including Hydrogen, Exciter Cooler Replacement and Exciter Upgrade)	B	Yes	2.3.3
15	Iso-Phase Bus Duct Fan and Coolers Replacement	B	Yes	2.3.3
16	Main StepUp Transformers Replacement	B	Yes	2.3.3
17	Addition of 19 kV Main Generator Breakers	B	Yes	2.3.3

Table 1.0-1
Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications

#	Modification	Category (A, B, C)(1)	Install Under 10 CFR 50.59	LR Section
18	Condenser – additional tube staking	B	Yes	2.5.5.2
19	345kV grid upgrades	B	Yes	2.3.2
20	Safeguards Bus Time Delay Relays	A	Yes	2.3.3
21	Risk Enhancement Modifications	C	Yes	2.13.1

Notes:
1. Category Key
   A. Required to support safety analyses at EPU power level
   B. Required to support operation at the EPU power level
   C. Risk enhancement modifications
2. The AST modifications (LAR 241) are required to support EPU
3. Final tie-into the AFW system and implementation requires prior NRC approval

Table 1.0-2
Comparison of PBNP and Ginna NSSS Design Parameters

Parameter	PBNP	GINNA
Total Core Power	1800 MWt	1775 MWt
System Pressure	2250 psia	2250 psia
Minimum Reactor Flow	89,000 gpm/loop	85,100 gpm/loop
Coolant Volume with Pressurizer	6000 ft^3 (Unit 1) 6148 ft^3(Unit 2)	6084 ft^3
Pressurizer Volume	1000 ft^3	800 ft^3
Maximum Core Inlet Temperature	542.9°F	540.2°F
Maximum Average Temperature	577.0°F	576.0°F
Maximum Core Outlet Temperature	615.3°F	611.8°F

Current Licensing Basis

The PBNP Current Licensing Basis (CLB) has been defined in accordance with the guidance of 10 CFR 54.3.

As noted in FSAR Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum

(AIF) version of the proposed General Design Criterion (ML003674718) (PBNP GDC).

In 1971 the Atomic Energy Commission issued Appendix A to 10 CFR 50, General Design Criteria, (36FR03255, dated 2/20/71). The Appendix A GDC were in many instances similar to the former AIF GDC, but they were expanded to include additional design considerations. Both PBNP GDC based on the AIF version and the Appendix A GDC are discussed in each section of the Licensing Report (LR). A comparison table is provided in Appendix C. The EPU LR also contains a brief description of PBNP's CLB with respect to the systems, structures and components (SSCs) or analysis under evaluation.

In December 2003, the NRC issued its Review Standard for Extended Power Uprate (EPU), RS-001. This License Amendment Request (LAR), submitted to support NRC approval of the proposed PBNP EPU, is intended to conform to the maximum practical extent to the guidance of RS-001. The regulatory review criteria portion of the RS-001 section details specific NRC review and acceptance criteria. The review standard acknowledges that there can, and will be, differences between the review standard and the design basis of a particular facility. The review standard contains provisions to ensure these differences do not impede the NRC staff's review. Consistent with the review standard and because PBNP's CLB predated Appendix A, additional details of PBNP's CLB are disucessed to provide a clear and concise summary of the licensing basis with respect to the SSC design or analyses.

Treatment of Issues Related to the Renewed Operating License

By letter dated February 25, 2004, Nuclear Management Company, LLC (NMC) submitted to the NRC an application requesting the Nuclear Regulatory Commission (NRC) to renew the PBNP Operating License for up to 20 additional years. The NRC reviewed the application in accordance with 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, utilizing the guidance of NUREG-1800, Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants. The NRC completed its review and approved the PBNP license renewal application as documented in NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (ML053420137) in December 2005 (Reference 1).

In the Safety Evaluation Report (SER), SSCs subject to aging management review are discussed in Sections 2.1 through 2.6. For those identified SSCs, the specific applicable aging management programs are discussed in Sections 3.1 through 3.7.

The requirements for renewal of nuclear power plant operating licenses are contained in 10 CFR 54 which identifies plant SSCs that are within the scope of the rule (10 CFR 54.21), as well as requirements for performing aging management reviews of those SSCs. Additionally, the rule requires an evaluation of time-limited aging analyses (TLAA) to account for the effects of aging on the intended functions of SSCs that are not subject to replacement based on a qualified life or specified time period. The TLAA are intended to ensure that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The operating conditions associated with the proposed extended power uprate (EPU) may increase certain operating parameters such as pressure, temperature, flow, and radiation compared to current operating conditions. In addition, the EPU introduces the possibility that components not currently within the scope of the rule (either currently installed in the plant or added as the result of EPU) may, as the result of EPU, meet the scoping inclusionary criteria detailed in the rule.

As discussed in each section of this LR which addresses specific SSCs, an evaluation of the impact of EPU on the extended period of operation of the plant was performed. The purpose of this evaluation was to identify which, if any, SSCs warranted additional aging management action. These may include SSCs subject to new aging effects because of changes in the operating environment resulting from EPU or the addition of, or modification to, components relied upon to satisfy EPU operating conditions.

SSCs relied upon for achieving the license renewal scoping objectives are evaluated within the structure or system that contains them. A limited number of plant components which were not included within the initial scope of License Renewal were evaluated within the context of the operating conditions associated with the proposed EPU. Any additional aging management actions associated with the extended period of plant operation are captured as internal commitments, which signify the need to modify the scope of license renewal aging management programs.

The potential impact of the proposed EPU on license renewal TLAA was also evaluated. Specifically, the evaluation considered any new aging effects or increases in degradation rates potentially created by the new EPU operating parameters.

Effect of EPU on Plant Programs

In addition to the aging management programs defined in the license renewal SER, numerous ongoing initiatives and processes used at the facility can be characterized as programs. In order to ensure these programs remain effective at EPU conditions, a review was performed to identify which, if any, programs could be impacted by the changes associated with EPU. The review considered two basic impacts:

- Does EPU increase the scope of an existing program? (i.e., should additional SSCs be included within the program boundary?) and
- Does EPU introduce new factors that should be accounted for within the parameters the program is trying to monitor or maintain? (i.e., does the technical basis for the program need to be modified to account for new or different plant or system conditions? Should a new program be created to monitor for new effects that are a result of EPU?)

Additionally, the review also considered the effects of EPU on the license renewal programs and the programs specifically called out in RS-001. The results of these reviews showed that some programs required an expansion of scope (e.g. flow accelerated corrosion), but no new programs were required and the existing programs adequately bound the parameters established as a result of EPU.

Changes required to the programs will be tracked by the PBNP Corrective Action Program.

Sections within the Licensing Report in addition to those specified in RS-001

The licensing report takes advantage of the provision in RS-001 to add additional sections (additional review areas). The following sections are in addition to the standard template:

1.0	Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report
1.1	Nuclear Steam Supply System Parameters
2.2.6	NSSS Design Transients
2.4.2.1	Plant Operability (Margin to Trip)
2.4.2.2	Pressurizer Control Component Sizing
2.5.8.1	Circulating Water System
2.7.7	Other Ventilation Systems (Containment)
2.8.5.0	Non-LOCA Analyses Introduction
2.8.7.1	Loss of Residual Heat Removal at Reduced Inventory
2.8.7.2	Natural Circulation Cooldown
2.10.2	Additional Review Areas (Health Physics)
Appendix A	Safety Evaluation Report Compliance
Appendix B	Additional Codes and Methods
Appendix C	Associated Technical Review Guidance
Appendix D	Supplemental Environmental Report
Appendix E	Setpoint Methodology

Use of Industry Operating Experience

Both the regulators and the nuclear industry peer groups strongly advocate incorporating operating experience and lessons learned as basic input in design, maintenance, operating and licensing activities. The analysis and evaluations performed for the PBNP EPU took full advantage of past EPU experiences by:

- Review of previous power uprate applicant NRC Requests for Additional Information (RAI). PWR RAIs issued over the past several years were reviewed and, where appropriate, the plant analyses or evaluations relating to the subject were reviewed against the expressed concern and documented to provide reviewer confidence that the issue was appropriately examined. (BWR RAIs were also reviewed when the RAI was related to issues other then those unique to BWRs.)
- NRC Staff interaction. During the development of this LAR, public meetings were held with the NRC Staff. At these meetings, the NRC Staff ensured that PBNP was aware of their growing body of lessons learned. When necessary, the Staff also held public meetings to

provide direct access to various technical review experts so they could directly communicate the experience they had gained from previous work.

- Review of Institute of Nuclear Power Operations communications relating to power uprates.
- Review of internal operating experience. During the analysis and evaluation activities attention was paid to ensure that system and component operating history was considered. Various system engineers were interviewed to ensure pertinent information was available for inclusion in the EPU evaluations. Component maintenance and trouble report histories were reviewed when appropriate to ensure that the changes made as a result of EPU would be factored into the installed capacity of the equipment, with an assessment of the remaining margin.
- Peer reviews. Peer reviews were held both at a project management level and at the functional working level (evaluation and analysis results review).

EPU Relation To Other Concurrent Licensing Activity

Concurrent PBNP License Amendment Requests

At the time of submittal of this LAR, there are two other LARs that are linked to the PBNP EPU LAR before the NRC that have not yet been approved.

EPU Related LARs

- LAR 241, Alternative Source Term (ML083450683)

  This amendment is a full implementation of the alterative source term methodology in accordance with Regulatory Guide 1.183. The radiological analyses associated with this amendment were performed at EPU power level and EPU source term, and is bounding for both the EPU power level as well as the current power level. LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, does not independently analyze this topic but refers to the previously submitted amendment (LAR 241).

- LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM {ML083330160}

  This amendment provides a reanalysis of the best estimate large break loss-of-coolant accident (BE LBLOCA) using the ASTRUM methodology in accordance with WCAP-16009-P-A. The BE LBLOCA analyses for Unit 1 and Unit 2 associated with this amendment were performed at the EPU power level, and are bounding for both current licensed power level as well as uprated proposed power level. LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents, Section 2.8.5.6.3.2 does not independently analyze this topic but refers to this previously submitted amendment (LAR 258).

Treatment of Proprietary Information referenced within the Licensing Report

Two versions of the LR have been prepared; a proprietary version and a non-proprietary version. The non-proprietary version will be provided as a separate transmittal and is for placement in the public document room. The proprietary version is for use by the NRC staff. The affidavits describing the nature of the information is provided in Attachment 6 and 8 of the PBNP EPU LAR. Bracketed [ ]^{a,c} information designates data that is Westinghouse Proprietary.

Plant Internal Commitment Tracking

In addition to the regulatory commitments detailed in Attachment 4 of this LAR, internal commitments related to EPU are tracked within the PBNP Regulatory Information System.

Objectives of Reliability and Risk Improvement

One additional objective for the PBNP EPU is to maintain or improve overall plant reliability and risk. This objective will be achieved through the planned plant modifications shown in Table 1.0-1, Point Beach Unit 1 and Unit 2 EPU Planned Major Modifications, above. EPU modifications, such as installation of the new 100% capacity motor-driven AFW pumps and other AFW system modifications, provide improved reliability for the AFW system.

Examples of modifications not required for EPU, but planned to improve overall plant risk include:

- Provide a backup compressed gas supply for the Pressurizer Auxiliary Spray Valve CV-296 inside containment on each unit.
- Provide an increased air supply to the motor-driven AFW pump mini-recirculation valves and flow control valves.
- Install a self-cooled (i.e., air-cooled) air compressor to supply Instrument Air independent of Service Water cooling and aligned for automatic operation.

LR Section 2.13, Risk Evaluation, documents the risk evaluation of these modifications and concludes that the risk increase associated with EPU will be more than offset through the implementation of these modifications.

Additional Information Provided

In addition to the information contained within this EPU submittal, the PBNP Final Safety Analysis Report (FSAR), as submitted in June 2008, is also contained on the reviewer's CD which includes the proprietary information. A separate CD without proprietary information and with out a copy of the FSAR will be provided for placement in ADAMS.

Table 1: List of Abbreviations

AC	Alternating Current
ADV	Atmospheric Dump Valve
AFW	Auxiliary Feedwater
AOR	Analysis of Record
AOV	Air-Operated Valves
AMSAC	ATWS Mitigation System Actuation Circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
ART	Adjusted Reference Temperature
ARV	Moisture Separator Reheater
ASME	American Society of Mechanical Engineers
ASTRUM	Automated Statistical Treatment of Uncertainty Method
ATWS	Anticipated Transient Without Scram
AVB	Anit-Vibration Bar
BELOCA	Best-Estimate LOCA
BOL	Beginning of Life
BOP	Balance of Plant
BL	Bulletin
BMI	Bottom-Mounted Instrumentation
BTP	Branch Technical Position
CAOC	Constant Axial Offset Control
CASS	Cast Austenitic Stainless Steel
CC	Component Cooling
CCW	Component Cooling Water
CDF	Core Damage Frequency
CLB	Current Licensing Basis

Table 1: List of Abbreviations

CF	Chemistry Factor
COLR	Core Operating Limit Report
CRDM	Control Rod Drive Mechanism
CST	Condensate Storage Tank
CUF	Cumulative Usage Factor
CVCS	Chemical and Volume Control System
DBA	Design Basis Accident
DBD	Design Basis Document
DBLOCA	Design Basis LOCA
DC	Direct Current
DHR	Decay Heat Removal
DNB	Departure From Nucleate Boiling
DNBR	Departure From Nucleate Boiling Rate
DOT	Department of Transportation
DPC	Doppler Power Coefficient
EAB	Exclusion Area Boundary
ECC	Emergency Core Cooling
ECCS	Emergency Core Cooling System
EFD	Equipment and Flood Drains
EFPY	Effective Full-Power Year
EHC	Electro-hydraulic Control
EM	Evaluation Model
EOC	End of Cycle
EOL	End of Life
EOLE	End of License Extension
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
EQ	Environmental Qualification

Table 1: List of Abbreviations

EQ	Equipment Qualification
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
FAC	Flow Accelerated Corrosion
FCV	Flow Control Valve
FF	Fluence Factor
FHAR	Fire Hazards Analysis Report
FIV	Flow-induced Vibration
FMEA	Failure Modes and Effects Analysis
FPER	Fire Protection Evaluation Report
FPP	Fire Protection Program
FPR	Fire Protection Report
FSAR	Final Safety Analysis Report
FSS	Fire Suppression System
GDC	General Design Criterion
GL	Generic Letter
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Absorption
HFP	Hot Full Power
HHSI	High Head Safety Injection
HP	High Pressure
HRA	Human Reliability Analysis
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
HZP	Hot Zero Power
I&C	Instrumentation and Control
IASCC	Irradiation-Assisted Stress Corrosion Cracking
ID	Inner Diameter

Table 1: List of Abbreviations

IEEE	Institute of Electrical and Electronic Engineers
IFBA	Intergral Fuel Burnable Absorber
IGSCC	Inter-granual Stress Corrosion Cracking
IPEEE	Individual Plant Examination of External Events
ISI	In-Service Inspection
ISLOCA	Interfacing System LOCA
IST	In-Service Testing
LAR	License Amendment Request
LBB	Leak Before Break
LBLOCA	Large-Break LOCA
LERF	Large Early Release Frequency
LHSI	Low Head Safety Injection
LOCA	Loss-of-Coolant Accident
LOL	Loss of Load
LONF	Loss of Normal Feedwater
LOOP	Loss-of-Offsite Power
LPZ	Low Population Zone
LR	Licensing Report
LSSS	Limiting Safety System Setting
LTOP	Low-Temperature Overpressure Protection
LWR	Light Water Reactor
M&E	Mass and Energy
M&TE	Measurement and Test Equipment
MCES	Main Condenser Evacuation System
MCO	Moisture Carryover
MDAFW	Motor-driven Auxiliary Feedwater
MFIV	Main Feedwater Isolation Valve
MMF	Minimum Measured Flow

Table 1: List of Abbreviations

MRP	Material Reliability Project
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSR	Moisture Separator Reheater
MSS	Main Steam System
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
MUR	Measurement Uncertainty Recapture
MW	Megawatts
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturer's Association
NFPA	National Fire Protection Association
NOP	Normal Operating Pressure
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRS	Narrow-Range Span
NSSS	Nuclear Steam Supply System
OBE	Operating Basis Earthquake
ODCM	Offsite Dose Calculation Manual
OFA	Optimized Fuel Assembly
P&ID	Piping and Instrumentation Diagram
PCT	Peak Cladding Temperature
PORV	Power-Operated Relief Valve
PTLR	Pressure and Temperature Limits Report
PRA	Probabilistic Risk Assessment
PRT	Pressurizer Relief Tank
P-T	Pressure-Temperature

Table 1: List of Abbreviations

PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
RAI	Request for Additional Information
RCC	Rod Cluster Control
RCCA	Rod Cluster Control Assembly
RCL	Reactor Coolant Loop
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RMS	Root Mean Square
RMS	Radiation Monitoring Systems
RMWS	Reactor Makeup Water System
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RRVCH	Replacement Reactor Vessel Closure Head
RSE	Reload Safety Evaluation
RTD	Resistance Temperature Detector
RTDP	Revised Thermal Design Procedure
RTP	Rated Thermal Power
RTS	Reactor Trip System
RV	Reactor Vessel
RVI	Reactor Vessel Internasl
RVLIS	Reactor Vessel Level Instrumentation System

Table 1: List of Abbreviations

RWST	Refuel Water Storage Tank
SAFDL	Specified Acceptable Fuel Design Limits
SAL	Safety Analysis Limit
SBLOCA	Small Break LOCA
SBO	Station Blackout
SCC	Stress Corrosion Cracking
SER	Safety Evaluation Report
SF	Spent Fuel
SFP	Spent Fuel Pool
SG	Steam Generator
SGB	Steam Generator Blowdown
SGTP	Steam Generator Tube Plugging
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIS	Safety Injection Signal
SFP	Spent Fuel Pool
SRP	Standard Review Plan
SSAR	Safe Shutdown Analysis Report
SSC	Structure, System, and Component
SSE	Safe Shutdown Earthquake
STDP	Standard Thermal Design Procedure
T-H	Thermal-Hydraulic
TC	Thermocouple
TDAFW	Turbine-Driven Auxiliary Feedwater
TDF	Thermal Design Flow
TEDE	Total Effective Dose Equivalent
TGSCC	Transgranular Stress Corrosion Cracking
TT	Turbine Trip

Table 1: List of Abbreviations

T/H	Thermal-Hydraulic
TLAA	Time-Limited Aging Analysis
TSP	Tube Support Plate
TS	Technical Specification
UPI	Upper Plenum Injection
UPS	Uninterruptible Power Supply
USE	Upper Shelf Energy
VAR	Volt-Ampere Reactive
VCT	Volume Control Tank
WOG	Westinghouse Owners Group

1.1 Nuclear Steam Supply System Parameters

The nuclear steam supply system (NSSS) design parameters are the fundamental parameters used as input in the NSSS and BOP analyses. The current PBNP Units 1 and 2 NSSS design parameters are summarized in Tables 4.1-1 through 4.1-9 of the PBNP updated Final Safety Analysis Report (FSAR). The NSSS design parameters provide the primary and secondary side system conditions (thermal power, temperatures, pressures, and flows) that serve as the basis for the NSSS analyses and evaluations. As a result of the Extended Power Uprate (EPU), the PBNP Units 1 and 2 NSSS design parameters have been revised as shown in Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate. Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate, provides information for the four cases associated with the EPU. These parameters have been incorporated, as required, into the applicable NSSS and BOP systems and components evaluations, as well as safety analyses, performed in support of the EPU. Table 1-2, Information for the Current NSSS Parameters for PBNP Units 1 and 2, provides information for the current operating NSSS parameters.

1.1.1 Input Parameters, Assumptions, and Acceptance Criteria

The NSSS design parameters, also referred to as the Westinghouse Performance Capability Working Group (PCWG) parameters, provide the reactor coolant system (RCS) and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations.

The computer code used to determine the NSSS design parameters was NSSSPlus (formerly SGPER). There is no explicit Nuclear Regulatory Commission (NRC) approval for the code since it is used to facilitate calculations that could be performed by hand. It uses basic thermal-hydraulic calculations, along with first principles of engineering, to generate the temperatures, pressures, and flows shown in Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate. The code and method used to calculate these values have been successfully used to license previous similar uprates for Westinghouse plants. Note that NSSSPlus encompasses the function of the former SGPER code without changing the mechanics of the calculations.

The major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for the PBNP Units 1 and 2 EPU are summarized by the following:

- The parameters are applicable to the existing Westinghouse Model 44F steam generators (SGs) in Unit 1 and Westinghouse Model Δ 47 SGs in Unit 2
- An uprated licensed reactor core power level of 1800 MWt (1806 MWt NSSS power) was used for the analyses
- A feedwater temperature (T_{feed}) range of 390.0°F to 458.0°F was used for the analyses
- Two design core bypass flows were assumed to be 6.5% (to account for thimble plugs removed) and 4.5% (to account for thimble plugs installed)
- The current thermal design flow (TDF) of 89,000 gpm/loop was maintained for the analyses

- A full-power normal operating vessel average temperature (T_{avg}) range of 558.0°F to 577.0°F was used
- Steam generator tube plugging (SGTP) levels of 0% and 10% were assumed
- A maximum steam generator moisture carryover of 0.25% was used
- The parameters are applicable to 14x14 422V+ fuel (used currently and also to be used for EPU)

Acceptance Criteria

The acceptance criteria for determining the NSSS design parameters were that the results of the EPU analyses and evaluations continue to comply with all industry and regulatory requirements applicable to PBNP Units 1 and 2, and that they provide adequate flexibility and margin during plant operation.

1.1.2 Description of Analyses and Evaluation

Table 1-1 provides the NSSS design parameter cases that were evaluated and serve as the basis for the EPU.

- EPU Cases 1 and 2 of Table 1-1 represent parameters based on a T_{avg} of 558.0°F, Case 1 is based on 0% SGTP.Case 2, which is based on an average 10% SGTP, yields the minimum secondary side steam generator pressure and temperature. Note that all primary side temperatures are identical for these two cases.
- EPU Cases 3 and 4 of Table 1-1 represent parameters based on the T_{avg} of 577.0°F. Case 3, which is based on an average 0% SGTP, yields the maximum secondary side steam pressure and temperature. Case 4 is based on an average of 10% SGTP. All primary side temperatures are identical for these two cases. As provided via note "d" of Table 1-1, for instances where an absolute upper limit steam pressure is more limiting for analysis purposes, this data is based on the Case 3 parameters with an assumed steam generator fouling factor of zero.

Best estimate calorimetric measurement-based secondary side performance parameters were also calculated for the EPU at the planned initial T_{avg} value of 576.0°F and are shown in Table 1-3, Best Estimate Calorimetric Measurement-based Performance Parameters for PBNP Units 1 and 2 Extended Power Uprate. These calorimetric measurement-based calculations were performed to estimate the actual expected steam conditions at the steam generator outlet as opposed to the design conditions shown in Table 1-1. The calorimetric measurement-based calculations for PBNP Unit 1 used plant measured calorimetric data from Cycle 31 and PBNP Unit 2 used plant measured calorimetric data from Cycle 29 to determine NSSS performance. The results were used in the Balance of Plant (BOP) analyses performed for the EPU.

1.1.3 Best Estimate RCS Flows

Best estimate RCS flows were calculated to support the EPU to determine whether adequate flow margin exists for the TDF and mechanical design flow (MDF) values established. The results of the Best Estimate RCS flow calculations are as follows:

- Best estimate RCS flow values of 98,700 gpm/loop at 0% SGTP and 96,100 gpm/loop at 10% SGTP for PBNP Unit 1
- Best estimate RCS flow values of 100,600 gpm/loop at 0% SGTP and 98,100 gpm/loop at 10% SGTP for PBNP Unit 2

1.1.4 Conclusions

The resulting NSSS design parameters (Table 1-1) were used by Westinghouse as the basis for the NSSS analytical efforts. Westinghouse performed the analyses and evaluations based on the parameter sets that were most limiting, so that the analyses would support operation over the entire range of conditions specified. PBNP concludes that the NSSS parameters established are suitable for use in the evaluation of NSSS systems, components and accidents for the EPU.

Table 1-1
NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate

Thermal Design Parameters	Extended Power Uprate Case 1	Case 2	Case 3	Case 4
NSSS Power, MWt	1806	1806	1806	1806
10^6 Btu/hr	6162	6162	6162	6162
Reactor Power, MWt	1800	1800	1800	1800
10^6 Btu/hr	6142	6142	6142	6142
Thermal Design Flow, loop gpm	89,000	89,000	89,000	89,000
Reactor 10^6 lb/hr	69.3	69.3	67.6	67.6
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	6.5 [a,b]	6.5 [a,b]	6.5 [a,c]	6.5 [a,c]
Reactor Coolant Temperature, °F				
Core Outlet	597.3 [b]	597.3 [b]	615.3 [c]	615.3 [c]
Vessel Outlet	592.9	592.9	611.1	611.1
Core Average	561.8 [b]	561.8 [b]	581.0 [c]	581.0 [c]
Vessel Average	558.0	558.0	577.0	577.0
Vessel/Core Inlet	523.1[f]	523.1[f]	542.9	542.9
Steam Generator Outlet	522.9[f]	522.9[f]	542.7	542.7
Steam Generator				
Steam Outlet Temperature, °F	490.8	486.3	511.6 [d]	507.3
Steam Outlet Pressure, psia	626	601	755 [d]	727
Steam Outlet Flow, 10^6 lb/hr total	7.36/8.08 [e]	7.36/8.08 [e]	7.39/8.12 [d,e]	7.39/8.11 [e]
Feed Temperature, °F	390.0/458.0	390.0/458.0	390.0/458.0	390.0/458.0
Steam Outlet Moisture, % max.	0.25	0.25	0.25	0.25
Tube Plugging Level, %	0	10	0	10
Zero Load Temperature, °F	547	547	547	547

Table 1-1
NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate

Thermal Design Parameters	Extended Power Uprate			
	Case 1	**Case 2**	**Case 3**	**Case 4**
Hydraulic Design Parameters				
Mechanical Design Flow, gpm per loop	101,200			
Minimum Measured Flow, gpm per loop	93,000			

Notes:

a. Core bypass flow accounts for thimble plugs removed.

b. If thimble plugs are installed, the core bypass flow is 4.5%, core outlet temperature is 595.9°F, and core average temperature is 561.0°F.

c. If thimble plugs are installed, the core bypass flow is 4.5%, core outlet temperature is 613.9°F, and core average temperature is 580.3°F.

d. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 813 psia, steam temperature of 520.1°F, and steam flow of 8.13×10^6 lb/hr should be assumed. This is to envelope the possibility that the plant could operate with better than expected steam generator performance.

e. Steam flow is affected by the two different feedwater temperatures.

f. Operating temperature for T_{cold} is not to be less than 525°F.

Table 1-2
Information for the Current NSSS Parameters for PBNP Units 1 and 2

Thermal Design Parameters	**Case 1**	**Case 2**	**Case 3**	**Case 4**
NSSS Power, MWt	1546	1546	1546	1546
10^6 Btu/hr	5275	5275	5275	5275
Reactor Power, MWt	1540	1540	1540	1540
10^6 Btu/hr	5255	5255	5255	5255
Thermal Design Flow, loop gpm	89,000	89,000	89,000	89,000
Reactor 10^6 lb/hr	68.8	68.8	67.4	67.4
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	6.5	6.5	6.5	6.5
Reactor Coolant Temperature, °F				
Core Outlet	592.0	592.0	607.2	607.2
Vessel Outlet	588.1	588.1	603.5	603.5
Core Average	561.2	561.2	577.2	577.2
Vessel Average	558.1	558.1	574.0	574.0
Vessel/Core Inlet	528.0	528.0	544.5	544.5
Steam Generator Outlet	527.8	527.8	544.2	544.2
Steam Generator				
Steam Outlet Temperature, °F	501.0	497.3	518.2	514.5
Steam Outlet Pressure, psia	687	664	800	775
Steam Outlet Flow, 10^6 lb/hr total	6.73	6.72	6.75	6.74
Feed Temperature, °F	438.1	438.1	438.1	438.1
Steam Outlet Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level, %	0	10	0	10
Zero Load Temperature, °F	547	547	547	547
Hydraulic Design Parameters				
Mechanical Design Flow, gpm per loop	101,200			
Minimum Measured Flow, gpm total	182,400			

Table 1-3
Best Estimate Calorimetric Measurement-based Performance Parameters for PBNP Units 1 and 2 Extended Power Uprate

Unit	NSSS Power (MWt)	Current SGTP (%)	T_{avg} (°F)	Steam Pressure (psia) [a]
1	1806	0.15	576.0	802
2	1806	0.055	576.0	806

Notes:

a. At the outlet of the SG nozzle, just downstream of the flow restrictor.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

2.1.1.1 Regulatory Evaluation

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the reactor vessel beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the reactor vessel. PBNP's review primarily focused on the effects of the proposed extended power uprate (EPU) on the reactor vessel surveillance capsule withdrawal schedule, which is discussed in Section 2.1.1.2.1 in more detail.

The NRC's acceptance criteria are based on:

- GDC 14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture
- GDC 31, insofar as it requires that the RCPB be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized
- 10 CFR 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the reactor vessel beltline region
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50, Appendix H

Specific review criteria are contained in the Standard Review Plan (SRP), Section 5.3.1, and other guidance provided in Matrix 1 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the reactor vessel material surveillance program are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement.

The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fact neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the Pressure Temperature Limits Report (PTLR) TRM 2.2. The Low Temperature Overpressure Protection System provides protection during low temperature operations.

All pressure retaining components of the Reactor Coolant System are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement.

CRITERION: Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided. (PBNP GDC 36)

The design of the reactor vessel and its arrangement in the system permits access during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel: the flange seal surface, the flange OD down to the cavity seal ring, the closure head and the nozzle to reactor coolant piping welds. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

Monitoring of the RT_{NDT} properties of the core region base material, weldments, and associated heat affected zones are performed in accordance with a surveillance program meeting the requirements of 10 CFR 50, Appendix H. Samples of reactor vessel plate, forging and weld materials are retained and catalogued and are available for future testing, as needed.

To define permissible operating conditions heatup and cooldown limit curves are established in accordance with the methods of analysis and the margins of safety of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G. In addition, the Low Temperature Overpressure Protection System using the power operated relief valves is activated whenever the reactor coolant system is not open to the atmosphere and the coolant temperature is less than criteria established by ASME Section XI.

The adequacy of the PBNP reactor vessel material surveillance program relative to conformance to the PBNP specific general design criteria (GDC) for Reactor Coolant Pressure Boundary

Rapid Propagation Failure Prevention and Reactor Coolant Pressure Boundary Surveillance are described in FSAR Chapter 1 Section 1.3.6, Reactor Coolant Pressure Boundary, and Chapter 4 Sections 4.1, Design Basis, 4.2, RCS System Design and Operation, 4.3, System Design Evaluation and 4.4, Tests and Inspections.

In addition to the evaluations described the FSAR Chapter 4, the PBNP reactor vessel material surveillance program was evaluated for plant license renewal, which is documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005 (NUREG-1839)

Additional license renewal information is provided in FSAR Section 15.2.18, Reactor Vessel Surveillance Program and FSAR Section 15.4.1, Reactor Vessel Irradiation Embrittlement.

2.1.1.2 Technical Evaluation

2.1.1.2.1 Background

Capsule W (referred to as Capsule A by Westinghouse in Reference 7) is a supplemental capsule that was inserted following Unit 2 Cycle 25 in order to measure the fracture toughness of PBNP Unit 2 weld metal, as well as materials from the PBNP Unit 1 vessel. The review of the effects of the EPU on the Capsule W withdrawal schedule indicates that Capsule W should be withdrawn as shown in Table 2.1.1-6, Recommended Surveillance Capsule Withdrawal Schedule for PBNP Units 1 and 2, when it accumulates a fluence corresponding to the maximum 53 EFPY reactor vessel fluence for consistency with recommendations in Reference 6. This capsule is planned for withdrawal at approximately 43 EFPY based on a previously planned smaller power uprate.

2.1.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The calculated (projected) fluence on the vessel was evaluated for the impact of the proposed EPU on the reactor vessel integrity. These fluence projections for various effective full-power years (EFPY) are presented in Table 2.1.1-1, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 1, and Table 2.1.1-2, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 2. Updated surveillance capsule fluence values are provided in Table 2.1.1-3, Calculated Integrated Neutron Exposure of the Point Beach Units 1 and 2 Surveillance Capsules.

Typically, vessel fluence values are used to evaluate end-of-license (EOL) transition temperature shifts (ΔRT_{NDT}) for development of surveillance capsule withdrawal schedules. The calculated fluence projections used in the EPU evaluation complied with Regulatory Guide 1.190. All of the neutron exposure evaluations for PBNP Units 1 and 2 used the NRC approved methodology described in Reference 3. This approved methodology follows the guidance and meets the requirements of Regulatory Guide 1.190 (Reference 4).

The chemistry factor (CF), along with the fluence factor (FF), is used to determine the ΔRT_{NDT}. The CF values used in this evaluation are presented in Table 2.1.1-4, Summary of Point Beach

Units 1 and 2 Material Chemistry Factor Values Based on Regulatory Guide 1.99, Revision 2, Position 1.1 and Position 2.1[a], and are documented in WCAP-15976, Revision 1 (Reference 5). Note that WCAP-15976 Revision 1 also contains the copper and nickel weight percent values that were used to calculate the chemistry factor values.

The temperature at which the surveillance capsule specimens and the reactor vessel materials below the inlet nozzles are irradiated is equal to the reactor vessel inlet temperature (T_{COLD}). Irradiation temperature is an important variable in consideration of the degree of embrittlement and use of the embrittlement correlations in Regulatory Guide 1.99, Revision 2.

Assumptions

Reactor vessel materials which accumulate a fluence of 1×10^{17} n/cm^2 (E > 1.0 MeV) or greater at 53 EFPY are considered in this analysis. For the purpose of the fluence analysis, the hafnium peripheral power suppression assembly (PPSA) removal date assumed was November 2008 for Unit 1 and October 2009 for Unit 2. The EPU implementation date assumed was April 2010 for Unit 1 and April 2011 for Unit 2. The actual dates for hafnium removal and EPU implementation may differ from the assumed dates. However, these dates are conservative for the purpose of the analysis.

Acceptance Criteria

The acceptance criteria for performing material surveillance of the reactor vessel, and for generating a withdrawal schedule are in 10 CFR Part 50, Appendix H and ASTM E185-82. A satisfactory number of surveillance capsules remain in the PBNP reactor vessels so that further analysis can be completed as necessary. BAW-1543(NP), Revision 4 (Reference 6) documents the Master Integrated Reactor Vessel Surveillance Program which meets the intent of ASTM E185-82.

The acceptance criteria for the T_{COLD} are provided in Regulatory Guide 1.99, Revision 2, Position 1.3, which states that , 'The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement'. Thus, the T_{COLD} must be greater than 525°F and less than 590°F for the equations and methodology of Regulatory Guide 1.99, Revision 2 to remain valid.

2.1.1.2.3 Description of Analyses and Evaluations

The reactor vessel surveillance capsule removal schedule evaluation for the proposed PBNP EPU includes a review of the T_{COLD} to verify that it complies with Regulatory Guide 1.99, Revision 2, and a review of the vessel fluence projections to determine if changes are required as a result of potential changes due to the EPU. This evaluation is consistent with the recommended practices of ASTM E185-82 and meets the requirements of 10 CFR Part 50, Appendix H.

As presented in LR Section 1.1, Nuclear Steam Supply System Parameters, the reactor vessel inlet temperature (T_{COLD}) will change with the proposed EPU operating conditions. A review of T_{COLD} for compliance with Regulatory Guide 1.99 Revision 2 indicates that T_{COLD} is intended to stay above 525°F for Cases 1 and 2 and changes to 542.9°F for Cases 3 and 4. This would be acceptable for Regulatory Guide 1.99 Revision 2 to continue to apply to the uprated conditions.

A surveillance capsule withdrawal schedule was developed to periodically remove surveillance capsules from the reactor vessel in order to effectively monitor the condition of the reactor vessel materials under actual operating conditions. ASTM E185-82 defines the recommended number of surveillance capsules, and the recommended withdrawal schedule, based on the predicted transition temperature shifts (ΔRT_{NDT}) of the vessel material. The ΔRT_{NDT} values for vessel materials from PBNP Units 1 and 2 are presented in Table 2.1.1-5, ΔRT_{NDT} Values for Point Beach Unit 1 and 2 Beltline Materials @ 53 EFPY for EPU.

The first surveillance capsule is usually scheduled to be withdrawn early in the vessel life to verify the initial predictions of the surveillance material response to the actual radiation environment. It is generally removed when the predicted shift exceeds the expected scatter by a sufficient margin to be measurable. Normally, the capsule with the highest lead factor is withdrawn first. Early withdrawal also permits verification of the adequacy and conservatism of the reactor vessel pressure temperature (P-T) operational limits. The withdrawal schedule for the maximum number of surveillance capsules to be withdrawn was adjusted by the lead factor so:

- The neutron fluence exposure of the second surveillance capsule withdrawn is midway between that of the first and third capsules.
- The exposure of the third surveillance capsule withdrawn does not exceed the peak end-of-life 1/4T fluence.
- The exposure of the fourth surveillance capsule withdrawn does not exceed the peak end-of-life reactor vessel fluence.
- The exposure of the fifth surveillance capsule withdrawn does not exceed twice the peak end-of-life reactor vessel fluence.

Per ASTM E185-82, the four steps used for the development of a surveillance capsule withdrawal schedule are as follows:

- Estimate the peak vessel inside surface fluence at end-of-life and the corresponding transition temperature shift (ΔRT_{NDT}). This identifies the number of capsules required. Per Regulatory Guide 1.99, Revision 2, RT_{NDT} is equal to the chemistry factor times the fluence factor. In the case of determining the number of capsules to be withdrawn, the peak vessel surface fluence is used to determine fluence factor.
- Obtain the lead factor for each surveillance capsule relative to the peak beltline fluence.
- Calculate the EFPY for the capsule to reach the peak vessel end-of-life fluence at the inside surface and 1/4T locations. These are used to establish the withdrawal schedule for all but the first surveillance capsule.
- Schedule the surveillance capsule withdrawals at the nearest vessel refueling date.

PBNP participates in the Master Integrated Reactor Vessel Surveillance Program, BAW—1543(NP), Revision 4 (Reference 6). As part of this program, replacement surveillance Capsule W containing materials closely matching the limiting materials for both Units 1 and 2 was installed in the Unit 2 Reactor Vessel following Cycle 25 and was placed in the 13° vacant Capsule R position. The newly installed capsule is planned for withdrawal during an outage at approximately 43 EFPY for consistency with recommendations of the Master Integrated Surveillance Program. PBNP Units 1 and 2 both have surveillance Capsule N planned for withdrawal between 27.2 and 51.5 EFPY. PBNP Unit 1 has withdrawn Capsules V, S, R, T, and P. PBNP Unit 2 has withdrawn Capsules V, T, R, S, and P.

A surveillance capsule withdrawal schedule for the PBNP reactor vessel is presented in Table 2.1.1-6, Recommended Surveillance Capsule Withdrawal Schedule for PBNP Units 1 and 2.

2.1.1.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

For License Renewal, Point Beach made the following commitments with respect to the Reactor Vessel Materials Surveillance Program as described in Appendix A of the Point Beach License Renewal SER (NUREG-1839):

- The integrity of the RPV will be directly validated with the testing of the capsule installed in Unit 2 in 2002, should extended operation be considered
- Capsule A2 (Unit 1) will be removed at a target EOLE fluence of 3.7×10^{19} n/cm2 (This capsule is at Crystal River as part of an industry program.) See BAW-1543 (NP) Revision 4 Supplement 6, for more information on this capsule.

PBNP has evaluated the impact of the EPU on these commitments and the conclusions reached in the PBNP License Renewal SER (NUREG-1839) for the Reactor Vessel Materials Surveillance Program. The first commitment is unaffected by PBNP EPU. However, the second commitment specifies a target EOLE fluence for capsule removal that was based on projected fluence levels at the time the License Renewal Application was submitted. PBNP will revise the License Renewal commitment to reflect the appropriate target EOLE fluence based on the EPU.

2.1.1.3 Results

Reactor vessel fluence projections and updated capsule fluence values were generated for the proposed EPU following the guidance of Regulatory Guide 1.190. Updated capsule fluence values are presented in Table 2.1.1-3, Calculated Integrated Neutron Exposure of the Point Beach Units 1 and 2 Surveillance Capsules.

The current surveillance capsule withdrawal schedules for the PBNP reactor vessels to date have been adjusted to continue to meet the intent of ASTM E185-82. For both units, Capsule P no longer meets the criteria for the fifth capsule with license renewal to 53 EFPY. These criteria should now be met by Capsule N for both units. The revised ΔRT_{NDT} values are presented in Table 2.1.1-5, ΔRT_{NDT} Values for Point Beach Unit 1 and 2 Beltline Materials @ 53 EFPY for EPU, and it shows that the maximum ΔRT_{NDT} using the uprated fluence projections for PBNP at 53 EFPY are greater than 200°F. Per ASTM E185-82, these ΔRT_{NDT} values require five capsules be withdrawn. This quantity is unchanged from the current withdrawal schedule. Thus, the only changes to the current withdrawal schedule are to the updated capsule fluence values, lead factors, and the notes referring to the timing of the future withdrawals as required for license renewal purposes. The proposed amendment to the withdrawal schedule is documented in Table 2.1.1-6, Recommended Surveillance Capsule Withdrawal Schedule for PBNP Units 1 and 2.

As presented in LR Section 1.1, Nuclear Steam Supply System Parameters, T_{COLD} is maintained above 525°F and below 590°F. The T_{COLD} for the uprated conditions will be 525°F for C. ases 1 and 2 and changes to 542.9°F for Cases 3 and 4. Therefore, the equations and results remain valid without adjustments for temperature affects.

2.1.1.4 Conclusions

PBNP has evaluated the effects of the proposed EPU on the reactor vessel surveillance withdrawal schedule and concludes that the newly presented withdrawal schedule adequately addressed changes in neutron fluence and their effects on the schedule. PBNP further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of the PBNP current licensing basis and PBNP GDC 34 and 36 following implementation of the proposed EPU. The acceptance criteria previously mentioned in Section 2.1.1.2.2 are also met. Therefore, PBNP finds the EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.1.5 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, December 2005
2. Point Beach Technical Requirements Manual (TRM) 2.2, Pressure Temperature Limits Report, Revision 5, May 30, 2008
3. WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006
4. Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001
5. WCAP-15976, Revision 1, Point Beach Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation, March 2008
6. BAW-1543(NP), Revision 4, Supplement 6-A, Supplement to the Master Integrated Reactor Vessel Surveillance Program, J.B. Hall, June 2007
7. WCAP-15856, Revision 0, Supplemental Reactor Vessel Surveillance Capsule "A" for the Point Beach Units 1 and 2 Reactor Vessel Installed in the Point Beach Unit 2 Reactor Vessel, May 2002

Table 2.1.1-1
Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 1

Neutron Fluence (n/cm^2, E > 1.0 MeV)							
Projected EFPY	Intermediate Shell Circ. Weld SA-1101	Lower Shell C-1423	Intermediate Shell A-9811	Intermediate Shell Long. Weld SA-775/812	Lower Shell Long. Weld SA-847	Upper Shell Circumferential Weld SA-1426	Upper Shell Forging 122P237
29.7	2.30E+19	2.33E+19	2.76E+19	1.75E+19	1.57E+19	1.77E+18	1.77E+18
31.0	2.43E+19	2.46E+19	2.89E+19	1.84E+19	1.66E+19	1.89E+18	1.89E+18
32.0	2.52E+19	2.56E+19	2.99E+19	1.91E+19	1.72E+19	1.97E+18	1.97E+18
33.0	2.62E+19	2.66E+19	3.09E+19	1.98E+19	1.79E+19	2.06E+18	2.06E+18
34.0	2.71E+19	2.76E+19	3.19E+19	2.04E+19	1.86E+19	2.15E+18	2.15E+18
35.0	2.81E+19	2.86E+19	3.29E+19	2.11E+19	1.93E+19	2.24E+18	2.24E+18
36.0	2.91E+19	2.96E+19	3.39E+19	2.18E+19	1.99E+19	2.33E+18	2.33E+18
37.0	3.00E+19	3.06E+19	3.49E+19	2.25E+19	2.06E+19	2.42E+18	2.42E+18
38.0	3.10E+19	3.16E+19	3.59E+19	2.31E+19	2.13E+19	2.50E+18	2.50E+18
39.0	3.20E+19	3.26E+19	3.69E+19	2.38E+19	2.19E+19	2.59E+18	2.59E+18
40.0	3.29E+19	3.36E+19	3.79E+19	2.45E+19	2.26E+19	2.68E+18	2.68E+18
41.0	3.39E+19	3.46E+19	3.89E+19	2.52E+19	2.33E+19	2.77E+18	2.77E+18
42.0	3.48E+19	3.56E+19	3.99E+19	2.59E+19	2.40E+19	2.86E+18	2.86E+18
43.0	3.58E+19	3.65E+19	4.09E+19	2.65E+19	2.46E+19	2.95E+18	2.95E+18
44.0	3.68E+19	3.75E+19	4.19E+19	2.72E+19	2.53E+19	3.03E+18	3.03E+18
45.0	3.77E+19	3.85E+19	4.29E+19	2.79E+19	2.60E+19	3.12E+18	3.12E+18

Table 2.1.1-1
Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 1

Neutron Fluence (n/cm^2, E > 1.0 MeV)							
Projected EFPY	**Intermediate Shell Circ. Weld SA-1101**	**Lower Shell C-1423**	**Intermediate Shell A-9811**	**Intermediate Shell Long. Weld SA-775/812**	**Lower Shell Long. Weld SA-847**	**Upper Shell Circumferential Weld SA-1426**	**Upper Shell Forging 122P237**
46.0	3.87E+19	3.95E+19	4.39E+19	2.85E+19	2.67E+19	3.21E+18	3.21E+18
47.0	3.96E+19	4.05E+19	4.49E+19	2.92E+19	2.73E+19	3.30E+18	3.30E+18
48.0	4.06E+19	4.15E+19	4.59E+19	2.99E+19	2.80E+19	3.39E+18	3.39E+18
49.0	4.16E+19	4.25E+19	4.69E+19	3.06E+19	2.87E+19	3.47E+18	3.47E+18
50.0	4.25E+19	4.35E+19	4.79E+19	3.13E+19	2.94E+19	3.56E+18	3.56E+18
51.0	4.35E+19	4.45E+19	4.89E+19	3.19E+19	3.00E+19	3.65E+18	3.65E+18
52.0	4.45E+19	4.55E+19	4.99E+19	3.26E+19	3.07E+19	3.74E+18	3.74E+18
53.0	4.54E+19	4.65E+19	5.09E+19	3.33E+19	3.14E+19	3.83E+18	3.83E+18

Table 2.1.1-2
Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 2

Neutron Fluence (n/cm^2, E > 1.0 MeV)					
Projected EFPY	**Intermediate Shell Circ. Weld SA-1484**	**Lower Shell 122W195**	**Intermediate Shell 123V500**	**Upper Shell Circ. Weld 21935**	**Upper Shell Forging 123V352**
29.1	2.29E+19	2.45E+19	2.63E+19	2.45E+18	2.45E+18
30.5	2.43E+19	2.60E+19	2.77E+19	2.61E+18	2.61E+18
31.0	2.47E+19	2.64E+19	2.82E+19	2.66E+18	2.66E+18
32.0	2.57E+19	2.75E+19	2.92E+19	2.78E+18	2.78E+18
33.0	2.67E+19	2.85E+19	3.02E+19	2.89E+18	2.89E+18
34.0	2.77E+19	2.95E+19	3.13E+19	3.01E+18	3.01E+18
35.0	2.87E+19	3.05E+19	3.23E+19	3.12E+18	3.12E+18
36.0	2.96E+19	3.15E+19	3.33E+19	3.24E+18	3.24E+18
37.0	3.06E+19	3.25E+19	3.43E+19	3.36E+18	3.36E+18
38.0	3.16E+19	3.36E+19	3.54E+19	3.47E+18	3.47E+18
39.0	3.26E+19	3.46E+19	3.64E+19	3.59E+18	3.59E+18
40.0	3.36E+19	3.56E+19	3.74E+19	3.70E+18	3.70E+18
41.0	3.46E+19	3.66E+19	3.84E+19	3.82E+18	3.82E+18
42.0	3.55E+19	3.76E+19	3.94E+19	3.94E+18	3.94E+18
43.0	3.65E+19	3.86E+19	4.05E+19	4.05E+18	4.05E+18
44.0	3.75E+19	3.96E+19	4.15E+19	4.17E+18	4.17E+18
45.0	3.85E+19	4.07E+19	4.25E+19	4.28E+18	4.28E+18
46.0	3.95E+19	4.17E+19	4.35E+19	4.40E+18	4.40E+18
47.0	4.05E+19	4.27E+19	4.45E+19	4.51E+18	4.51E+18
48.0	4.14E+19	4.37E+19	4.56E+19	4.63E+18	4.63E+18
49.0	4.24E+19	4.47E+19	4.66E+19	4.75E+18	4.75E+18
50.0	4.34E+19	4.57E+19	4.76E+19	4.86E+18	4.86E+18
51.0	4.44E+19	4.68E+19	4.86E+19	4.98E+18	4.98E+18
52.0	4.54E+19	4.78E+19	4.96E+19	5.09E+18	5.09E+18
53.0	4.63E+19	4.88E+19	5.07E+19	5.21E+18	5.21E+18

Table 2.1.1-3
Calculated Integrated Neutron Exposure of the Point Beach Units 1 and 2 Surveillance Capsules

Capsule ID	Withdrawal EFPY	Fluence (10^{19} n/cm^2, E > 1.0 MeV)	Capsule Lead Factor
Point Beach Unit 1			
V	1.5	0.620	2.95
S	3.6	0.808	1.65
R	5.1	2.12	3.02
T	9.3	2.14	1.83
P	17.8	3.86	1.99
Point Beach Unit 2			
V	1.5	0.651	2.95
T	3.4	0.857	1.74
R	5.2	2.16	2.99
S	14.8	3.04	1.86
P	19.5	4.03	2.02

Table 2.1.1-4
Summary of Point Beach Units 1 and 2 Material Chemistry Factor Values Based on Regulatory Guide 1.99, Revision 2, Position 1.1 and Position 2.1[a]

Material Description	Material Identification	Chemistry Factor	
		Position 1.1	Position 2.1
Point Beach Unit 1			
Nozzle Belt Forging (NB)	122P237	77	---
Intermediate Shell (IS)	A9811-1	88	79.3
Lower Shell (LS)	C1423-1	55.3	35.8
NB to IS Circ. Weld	SA-1426	152.4	---
IS Long. Weld (ID 27%)	SA-812	138.2	---
IS Long. Weld (OD 73%)	SA-775	157.6	---
IS to LS Circ. Weld	SA-1101	167.6	---
LS Long. Weld	SA-847	157.4	163.3
Point Beach Unit 2			
Nozzle Belt Forging (NB)	123V352	76	---
Intermediate Shell (IS)	123V500	58	---
Lower Shell (LS)	122W195	31	43
NB to IS Circ. Weld	21935	170	---
IS to LS Circ. Weld	SA-1484	180	---

Notes:

a. All chemistry factor values are taken from WCAP-15976, Revision 1 (Reference 5)

Table 2.1.1-5
ΔRT_{NDT} Values for Point Beach Unit 1 and 2 Beltline Materials @ 53 EFPY for EPU

Material Description	CF	53 EFPY Fluence (n/cm^2, E >1.0 MeV)	$FF^{(a)}$	$\Delta RT_{NDT}^{(b)}$
Point Beach Unit 1				
Nozzle Belt Forging (NB)	77°F	0.383×10^{19}	0.73	56.6
Intermediate Shell (IS)	88°F	5.09×10^{19}	1.41	123.7
* Using surveillance data	79.3°F	5.09×10^{19}	1.41	111.5
Lower Shell (LS)	55.3°F	4.65×10^{19}	1.39	76.8
* Using surveillance data	35.8°F	4.65×10^{19}	1.39	49.7
NB to IS Circ. Weld	152.4°F	0.383×10^{19}	0.73	111.9
IS Long. Weld (ID 27%)	138.2°F	3.33×10^{19}	1.32	181.8
IS to LS Circ. Weld	167.6°F	4.54×10^{19}	1.38	231.8
LS Long. Weld	157.4°F	3.14×10^{19}	1.30	204.9
* Using surveillance data	163.3°F	3.14×10^{19}	1.30	212.3
Point Beach Unit 2				
Nozzle Belt Forging (NB)	76°F	0.521×10^{19}	0.82	62.2
Intermediate Shell (IS)	58°F	5.07×10^{19}	1.41	81.5
Lower Shell (LS)	31°F	4.88×10^{19}	1.40	43.3
* Using surveillance data	43°F	4.88×10^{19}	1.40	60.1
NB to IS Circ. Weld	170°F	0.521×10^{19}	0.82	139.0
IS to LS Circ. Weld	180°F	4.63×10^{19}	1.39	249.7

Notes:

a. FF = Fluence Factor = $f^{(0.28 - 0.1 \log f)}$, where f is the clad/base metal interface fluence.
b. Per Regulatory Guide 1.99 Revision 2, ΔRT_{NDT} = CF * FF (°F).

Table 2.1.1-6
Recommended Surveillance Capsule Withdrawal Schedule for PBNP Units 1 and 2

Capsule	Location	Lead Factor	Withdrawal EFPY[a]	Fluence (n/cm^2)
Point Beach Unit 1				
V	13°	2.95	1.5	0.620×10^{19}
S	33°	1.65	3.6	0.808×10^{19}
R	13°	3.02	5.1	2.12×10^{19}
T	23°	1.83	9.3	2.14×10^{19}
P	23°	1.99	17.8	3.86×10^{19}
N	33°	1.93	Standby[b]	(b)
Point Beach Unit 2				
V	13°	2.95	1.5	0.651
T	23°	1.74	3.4	0.857
R	13°	2.99	5.2	2.16
S	33°	1.86	14.8	3.04
P	23°	2.02	19.5	4.03
N	33°	1.97	Standby[c]	(c)
W	13°[d]	1.41	Standby[e]	(e)

Notes:

a. Effective Full Power Years (EFPY) from plant startup, unless otherwise indicated.

b. This capsule should be withdrawn between 27.2 and 51.5 EFPY, which is the window when the capsule would exceed one times the peak 53 EFPY fluence of 5.09E+19 n/cm^2 and be less than two times the peak 53 EFPY fluence of 1.02E+20 n/cm^2.

c. This capsule should be withdrawn between 27.2 and 51.5 EFPY, which is the window when the capsule would exceed one times the peak 53 EFPY fluence of 5.07E+19 n/cm^2 and be less than two times the peak 53 EFPY fluence of 1.01E+20 n/cm^2.

d. Per WCAP-15856, Revision 0 (Reference 7).

e. Inserted at the end of cycle 25 as recorded in BAW-1543(NP), Revision 4, Supplement 6-A (Reference 6). This capsule should be withdrawn at 43 EFPY with a fluence of 5.07E+19 n/cm^2 to be consistent with Reference 6, the Master Integrated Reactor Vessel Surveillance Program. Refer to Section 2.1.2.1 for more information about this capsule. Note that Capsule W is also referred to as Capsule A.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

2.1.2.1 Regulatory Evaluation

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the reactor coolant pressure boundary during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. PBNP's review of P-T limits covered the P-T limits methodology and the calculations for the number of effective full-power years (EFPYs) specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

NRC's acceptance criteria for P-T limits are based on:

- GDC 14, insofar as it requires that the reactor coolant pressure boundary be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating failure
- GDC 31, insofar as it requires that the reactor coolant pressure boundary be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized
- 10 CFR 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the reactor coolant pressure boundary
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50, Appendix G

Specific review criteria are contained in the SRP, Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criteria (PBNP GDC).

The PBNP specific GDC for Pressure-Temperature Limits and Upper Shelf Energy are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement.

The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fact neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RTNDT), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the PBNP Pressure Temperature Limits Report (PTLR). The Low Temperature Overpressure Protection System provides protection during low temperature operations.

All pressure containing components of the Reactor Coolant System (RCS) are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement.

CRITERION: Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided. (PBNP GDC 36)

The design of the reactor vessel and its arrangement in the system permits access during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel: the flange seal surface, the flange OD down to the cavity seal ring, the closure head and the nozzle to reactor coolant piping welds. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

Monitoring of the RT_{NDT} properties of the core region base material, weldments, and associated heat affected zones are performed in accordance with a surveillance program meeting the requirements of 10 CFR 50, Appendix H.

To define permissible operating conditions, heatup and cooldown limit curves are established in accordance with the methods of analysis and the margins of safety of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G. In addition, the Low Temperature Overpressure Protection System using the power operated relief valves is activated whenever the reactor coolant system is not open to the atmosphere and the coolant temperature is less than criteria established by ASME Section XI.

The adequacy of the PBNP pressure-temperature limits and upper shelf energy relative to conformance to the PBNP GDC for Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention is described in FSAR Chapter 1 Section 1.3.6, Reactor Coolant Pressure Boundary, and Chapter 4 Sections 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 4.3, System Design Evaluation and 4.4, Tests and Inspections. FSAR Section 7.4.2, Low Temperature Overpressure Protection (LTOP) describes the automatic protection system that protects the reactor vessel from exceeding the 10 CFR 50, Appendix G allowable pressure limits at low temperatures.

The pressure-temperature limits and upper shelf energy were evaluated for the PBNP License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Additional license renewal information is provided in FSAR Section 15.2.18, Reactor Vessel Surveillance Program and FSAR Section 15.4.1, Reactor Vessel Irradiation Embrittlement.

As described in FSAR Section 15.4.1, Reactor Vessel Irradiation Embrittlement, to address the period of extended operation associated with the PBNP license renewal project, the end of license extension projected fluences and the RPV material properties were used to determine the limiting materials and calculate pressure-temperature limits for heatup and cooldown. The current PBNP Unit 1 and 2 heatup and cooldown pressure-temperature limit curves were generated using adjusted reference temperature (ART) values that bound both units. The highest ART values from the two units were from the Unit 1 and Unit 2 intermediate-to-lower shell girth welds. However, the limiting materials are actually the intermediate and lower shell axial welds from Unit 1, depending on the vessel thickness (1/4 T or 3/4 T location). The axial welds become limiting over the girth weld through use of "circ-flaw" methodology from ASME Code Case N-588. This methodology is less restrictive than the standard "axial-flaw" methodology from the 1995 ASME Code, Section XI through the 1996 Addenda. In addition to the use of Code Case N-588, the PT curves also made use of ASME Code Case N-640, which allows the use of the KIc methodology. Both ASME Code Case N-588 and N-640 were joined together under ASME Code Case N-641.

The analysis associated with reactor vessel pressure-temperature limit curves has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The PBNP license renewal project determined that, for PBNP, the Charpy upper shelf energy (USE) for the limiting welds will be less than 50 ft-lbs based on Regulatory Guide 1.99, Revision 2, at 53 effective full power years (EFPY). Therefore, in order to demonstrate that sufficient margins of safety against fracture remain to satisfy the requirements of Appendix G to 10 CFR Part 50, a fracture mechanics evaluation was performed to examine the PBNP USE values in the limiting weld. The evaluation examined the USE values for end of license extension (EOLE) conditions. The PBNP fracture mechanics evaluation used the J-R ratio methodology, which demonstrates the acceptability of J-R values in satisfying the USE requirement by examining J-R ratios, which are defined as the ratio of the lower bound J-R value divided by the applied J. If this ratio is greater than or equal to one, the acceptance criteria are met. This methodology is described in B&W Owners Reactor Vessel Working Group reports BAW-2192-PA, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level A & B Service Loads, and BAW-2178-PA, Low Upper Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Level C & D Service Loads, both dated April 1994. The NRC staff reviewed and approved both reports for referencing in licensing applications in separate letters dated March 29, 1994.

Additional equivalent margins analyses were performed for the PBNP RPVs to address the following EOLE (53 EFPY) conditions: the uprated power condition of 1678 megawatts thermal (MWt) without hafnium suppression assemblies; current power conditions of 1540 MWt without hafnium suppression assemblies; and current power conditions of 1540 MWt with hafnium suppression assemblies. The 2004 fluence projections were used to define EOLE vessel fluences. These analyses used the same methodologies described in the above references and are summarized in BAW-2467P, Revision 1. The NRC reviewed and accepted this analysis for PBNP in the Safety Evaluation Report transmitted by NRC Letter dated May 10, 2007. (Reference 7)

The analysis associated with upper-shelf energy has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

2.1.2.2 Technical Evaluation

2.1.2.2.1 Background

Reactor vessel integrity is potentially impacted by any change in plant parameters that affect neutron fluence levels or P-T transients. The changes in neutron fluence resulting from the EPU were evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the PBNP Units 1 and 2 P-T limits and the end of license (EOL) and end of license extension (EOLE) assessment of upper shelf energy.

2.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The calculated (projected) fluence on the vessel was evaluated for the impact of the proposed EPU on the reactor vessel integrity evaluations. These fluence projections for various EFPY are presented in Table 2.1.1-1, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 1, and Table 2.1.1-2, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 2. Updated surveillance capsule fluence values are provided in Table 2.1.1-3, Calculated Integrated Neutron Exposure of the Point Beach Units 1 and 2 Surveillance Capsules. See LR Section 2.1.1, Reactor Vessel Material Surveillance Program.

Typically, fluence values are used to calculate the EOL transition temperature shift (EOL ΔRT_{NDT}) for development of the P-T limits. The calculated fluence projections used in the EPU evaluation complied with Regulatory Guide 1.190. All of the neutron exposure evaluations for PBNP Units 1 and 2 used the NRC approved methodology described in Reference 3. This approved methodology follows the guidance and meets the requirements of Regulatory Guide 1.190 (Reference 4).

The temperature at which the surveillance capsule specimens and the reactor vessel materials below the inlet nozzles are irradiated is equal to the reactor vessel inlet temperature (T_{COLD}). Irradiation temperature is an important variable in consideration of the degree of embrittlement and use of the embrittlement correlations in Regulatory Guide 1.99, Revision 2.

Per BAW-2467(NP), Revision 1 (Reference 5), the Charpy upper-shelf energy (USE) value for the PBNP Units 1 and 2 limiting weld materials dropped below 50 ft-lbs. In order to demonstrate that the vessel has an adequate margin of safety against fracture, a low upper-shelf toughness fracture mechanics analysis (i.e. an equivalent margins analysis, EMA) was performed in BAW-2467, Revision 1 to satisfy 10 CFR Part 50, Appendix G.

The P-T limit curves are presently contained in the PTLR, TRM 2.2 (Reference 2), and are documented in WCAP-15976, Revision 1. A new applicability date for the EOL P-T limit curves in WCAP-15976, Revision 1 was determined. The new applicability date was determined for the case with uprate without hafnium.

Assumptions

Reactor vessel materials which accumulate a fluence of 1×10^{17} n/cm^2 (E > 1.0 MeV) or greater at 53 EFPY for Unit 1 and 35.9 EFPY for Unit 2 are considered in this analysis. For the purpose of the fluence analysis, the hafnium peripheral power suppression assembly (PSSA) removal date assumed was November 2008 for Unit 1 and October 2009 for Unit 2. The EPU implementation date assumed was April 2010 for Unit 1 and October 2009 for Unit 2. The actual dates for hafnium removal and EPU implementation may differ from the assumed dates. However, these dates are conservative for the purpose of the analysis.

Acceptance Criteria

PBNP must have NRC-approved P-T limits developed in accordance with 10 CFR Part 50, Appendix G, and the applicable EFPY of those P-T limit curves after implementation of the proposed EPU is known.

For USE at EPU conditions, the EOL USE values for all reactor beltline materials must meet the requirements of 10 CFR Part 50, Appendix G, which states the USE must be maintained above 50 ft-lbs, otherwise an equivalent margins analysis (EMA) must be performed to demonstrate that the vessel has an adequate margin of safety equivalent to that provided in 10 CFR Part 50 Appendix G.

For the vessel inlet temperature, the acceptance criteria are from Regulatory Guide 1.99, Revision 2, Position 1.3, which states that, The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement. Thus, the T_{COLD} must be greater than 525°F and less than 590°F for the equations and methodology to remain valid.

2.1.2.2.3 Description of Analyses and Evaluations

Applicability of P-T Limit Curves

The current analyses of record for the P-T limit curves are documented in WCAP-15976 Revision 1. This analysis of record was reviewed and approved including the use of the FERRET code at PBNP (Reference 8). Reactor vessel fluence projections considering the EPU were slightly higher (at 36.9 EFPY) than those of WCAP-15976 Revision 1 (Reference 6) for the 36.9 EFPY case without hafnium. Therefore, a new applicability date of those P-T limit curves was calculated for the 36.9 EFPY without hafnium case using the EPU fluence projections.

The evaluation of the term of applicability was carried out by comparing the fluence projections used in the calculations of adjusted reference temperature for the EOL P-T limit curves in WCAP-15976, Revision 1 (Reference 6), to the EPU vessel fluence projections (see Table 2.1.2.-1, Summary of the Surface Fluence Values for PBNP Units 1 & 2 for 36.9 EFPY ($x10^{19}$ n/cm^2, E > 1.0 MeV)). The fluence values used in the WCAP-15976, Revision 1, 36.9 EFPY without hafnium analysis are listed in Table 2.1.2.-1. The EPU EFPY term corresponding to the same fluence as used in WCAP-15976, Revision 1 was calculated and listed in Table 2.1.2.-1 for each beltline material. The most limiting EFPY (lowest) was then chosen to reflect the EPU applicability date for the P-T limit curves that were already developed in WCAP- 15976, Revision 1. Since the values were equal or slightly lower under EPU conditions at 35.9 EFPY than in the 36.9 EFPY with no hafnium case in Reference 6, as seen in Table 2.1.2.-1, the new applicability date for those P-T limit curves will be changed to 35.9 EFPY, which corresponds to calendar year 2015 for Units 1 and 2.

USE

Applicability of the results documented in BAW-2467, Revision 1 (Reference 7) was reviewed as a part of the EPU. The analysis focused on the beltline welds that were projected to have the lowest USE after irradiation. The fluence values used in the EMA were higher when compared to the fluence values for the EPU (see Table 2.1.2.-2, PBNP Units 1 53 EFPY Fluence Comparison, for the 53 EFPY Unit 1 fluence comparison and Table 2.1.2-3 for the 35.9 EFPY Unit 2 fluence comparison). Hence, the analysis in BAW-2467, Revision 1 (Reference 5) is conservative and remains applicable for the projected EPU fluence values. The equivalent margins analysis performed therefore demonstrates that the limiting PBNP Units 1 and 2 reactor vessel beltline welds will continue to satisfy the acceptance criteria of Appendix G to 10 CFR 50 for the projected conditions through 53 EFPY and 35.9 EFPY, respectively.

2.1.2.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached in the Point Beach License Renewal SER (NUREG-1839) for the P-T limits and USE of all the beltline materials. The aging evaluations in SER Section 4.2 for the beltline materials with respect to USE and P-T Limits remain valid for EPU conditions.

2.1.2.3 Results

Applicability of Heatup and Cooldown P-T Limit Curves

A review was completed on the EOL P-T limit curve applicability date for PBNP. This review indicated that the revised fluence projections associated with the proposed EPU did not exceed the fluence projections used in developing the current adjusted reference temperature values for PBNP WCAP-15976 Revision 1 at 53 EFPY.

USE

Based on the EPU fluence projections, all beltline materials are expected to have a USE greater than 50 ft-lb through EOL (53 EFPY), as required by 10 CFR Part 50, Appendix G, except the beltline welds for both PBNP Units 1 and 2.

The limiting beltline weld materials were already predicted to drop below 50 ft-lbs prior to this evaluation and consideration of the EPU. So an EMA showing sufficient margin had already been performed. The Unit 1 EPU 53 EFPY fluence values are lower than the fluence values used in the EMA, as seen in Table 2.1.2.-2. The Unit 2 EPU 35.9 EFPY fluence values are lower than the fluence values used in the EMA, as seen in Table 2.1.2.-3.

From BAW-2467(NP), Revision 1 (Reference 5), the ratio of J_0/J_1 for the weld is 1.87, which is significantly higher than the required value of 1.0. Additionally, when using a factor of safety of 1.25 for pressure and 1.0 for thermal loading, flaw extensions are ductile and stable. Hence, the analysis in BAW-2467 is conservative and remains applicable for the projected EPU EOL and EOLE fluence values. The equivalent margins analysis performed therefore demonstrates that the limiting PBNP Units 1 and 2 reactor vessel beltline welds will continue to satisfy the acceptance criteria of Appendix G to Section XI of the ASME Code for the projected conditions to 53 and 35.9 EFPY, respectively.

Inlet Temperature

The T_{COLD} will be maintained above 525°F and below 590°F (see LR Section 1.1, Nuclear Steam Supply System Parameters). The T_{COLD} for the uprated conditions will be 525°F for Cases 1 and 2 and changes to 542.9°F for Cases 3 and 4. Therefore, the equations and results remain valid without adjustments for temperature affects.

The fluence projections under EPU condition, while considering actual PBNP power distributions incorporated to date do not exceed fluence projections used in the development of the P-T limit curves in WCAP-15976, Revision 1 (Reference 6) at EOL (35.9 EFPY). Therefore the P-T limits developed in this reference are now applicable to 35.9 EFPY. The 35.9 fluence projections also do not exceed fluence values used in the EMA USE evaluation in BAW-2467(NP), Revision 1 (Reference 5) for the limiting reactor vessel materials. Therefore this analysis is conservative and is applicable through 35.9 EFPY. Lastly, since the inlet temperature is to be maintained between 525°F and 590°F, the equations for calculating the adjusted reference temperatures and predicting USE remain valid without any adjustments.

2.1.2.4 Conclusions

PBNP has reviewed the evaluation of the effects of the proposed EPU on the P-T limits and concludes that the changes in neutron fluence have been adequately addressed on P-T limits. Based on the results presented in Section 2.1.2.3, Results, for operation at the proposed EPU conditions, the requirements of 10 CFR Part 50, Appendix G are met and the current TRM P-T curves are valid through 35.9 EFPY. This meets the PBNP current licensing basis with respect to PBNP GDC 34 and 36. Therefore, PBNP finds the EPU acceptable with respect to the reactor vessel P-T limits.

2.1.2.5 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, December 2005

2. Technical Requirements Manual (TRM) 2.2, Pressure Temperature Limits Report, Revision 5, May 30, 2008

3. WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006

4. Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001

5. Areva Report BAW-2467(NP), Revision 1, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Point Beach Units 1 and 2 for Extended Life through 53 Effective Full Power Years, H.P. Gunawardane, October 2004

6. WCAP-15976, Revision 1, Point Beach Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation, March 2008

7. NRC to NMC, LLC, Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Regarding Review of Reactor Vessel Fracture Mechanics Analysis, May 10, 2007

8. NRC to FPLE Point Beach, Point Beach Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Reactor Coolant System Pressure and Temperature Limits Report Technical Specification 5.6.5, October 18, 2007

Table 2.1.2.-1
Summary of the Surface Fluence Values for PBNP Units 1 & 2 for 36.9 EFPY ($x10^{19}$ n/cm^2, E > 1.0 MeV)

Component Description	WCAP-15976, Revision 1 - 36.9 EFPY Analysis (without hafnium)	Corresponding EFPY using Uprated Analysis[a]
Point Beach Unit 1		
Nozzle Belt Forging	0.25	38.0
Intermediate Shell	3.38	35.9
Lower Shell	3.04	36.8
NB to IS Circ. Weld	0.25	38.0
IS Long. Weld	2.19	36.1
IS to LS Circ. Weld	3.05	37.5
Lower Shell Long. Weld	2.08	37.3
Point Beach Unit 2		
Nozzle Belt Forging	0.34	37.4
Intermediate Shell	3.38	36.5
Lower Shell	3.30	37.5
NB to IS Circ. Weld	0.34	37.4
IS to LS Circ. Weld	3.13	37.7

Note:
(a)The EFPY were obtained through interpolation of Tables 2.1.1-1 and 2.1.1-2

Table 2.1.2.-2
PBNP Units 1 53 EFPY Fluence Comparison

Material	53 EFPY Surface Fluence[a] ($x10^{19}$ n/cm^2)	53 EFPY EPU Surface Fluence ($x10^{19}$ n/cm^2)
LS Long. Weld SA-847	3.25	3.14
IS to LS Circ Weld SA-1101	4.71	4.54

Note:
a. Condition 1 fluence values per BAW-2467(Reference 5), which bound Conditions 2 and 3 that were also analyzed

Table 2.1.2.-3
PBNP Units 2 35.9 EFPY Fluence Comparison

Material	53 EFPY Surface Fluence[a] ($x10^{19}$ n/cm^2)	35.9 EFPY EPU Surface Fluence ($x10^{19}$ n/cm^2)
IS to LS Circ. Weld SA-1484	4.85	2.95

Note:
a. Condition 1 fluence values per BAW-2467(Reference 5), which bound Conditions 2 and 3 that were also analyzed

2.1.3 Pressurized Thermal Shock

2.1.3.1 Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the reactor vessel beltline materials to PTS events to ensure that adequate fracture toughness is provided for supporting reactor operation. PBNP's review covered the PTS methodology and the calculations for the reference temperature, (RT_{PTS}), at the expiration of the license, considering neutron embrittlement effects.

The NRC's acceptance criteria for PTS are based on:

- GDC 14, insofar as it requires that the reactor coolant pressure boundary be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture
- GDC 31, insofar as it requires that the reactor coolant pressure boundary be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized
- 10 CFR 50.61, insofar as it sets fracture toughness criteria for protection against PTS events

Specific review criteria are contained in the SRP, Section 5.3.2, and other guidance provided in Matrix 1 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for Pressurized Thermal Shock are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

The Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the Reactor Coolant System is carried out in accordance with the applicable codes at the time of fabrication. In addition, there are areas where specifications for Reactor Coolant System components go beyond the applicable codes.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement.

The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fact neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Code Section XI and are included in the PBNP Pressure Temperature Limits Report (PTLR). The Low Temperature Overpressure Protection System provides protection during low temperature operations.

All pressure containing components of the Reactor Coolant System (RCS) are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement.

CRITERION: Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided. (PBNP GDC 36)

The design of the reactor vessel and its arrangement in the system permits access during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel: the flange seal surface, the flange OD down to the cavity seal ring, the closure head and the nozzle to reactor coolant piping welds. The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

Monitoring of the RT_{NDT} properties of the core region base material, weldments, and associated heat affected zones are performed in accordance with a surveillance program meeting the requirements of 10 CFR 50, Appendix H. Samples of reactor vessel plate and forging materials are retained and catalogued and are available for future testing, as needed.

To define permissible operating conditions heatup and cooldown limit curves are established in accordance with the methods of analysis and the margins of safety of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G. In addition, the Low Temperature Overpressure Protection System using the power operated relief valves is activated whenever the reactor coolant system is not open to the atmosphere and the coolant temperature is less than criteria established by ASME Section XI.

The adequacy of the PBNP Pressurized Thermal Shock evaluation relative to conformance to the PBNP GDC for Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention and Reactor Coolant Pressure Boundary Surveillance are described in FSAR Chapter 1 Section 1.3.6, Reactor Coolant Pressure Boundary, and Chapter 4 Sections 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 4.3, System Design Evaluation and 4.4, Tests and Inspections.

In addition to the evaluations described the FSAR Chapter 4, the PBNP reactor vessel material surveillance program was evaluated for plant License Renewal, which is documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

Additional license renewal information is provided in FSAR Section 15.2.18, Reactor Vessel Surveillance Program and FSAR Section 15.4.1, Reactor Vessel Irradiation Embrittlement.

The calculated RT_{PTS} values at the end of life extension for the PBNP Units 1 and 2 reactor vessels are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds, with the exception of the Unit 2 RPV intermediate to lower shell circumferential weld.

The EOLE fluence yields an RT_{PTS} value of 316°F when using Charpy based methods for the limiting weld of the Unit 2 RPV. The screening criteria established in 10 CFR 50.61 (300°F) will be exceeded for the limiting Unit 2 intermediate-to-lower shell girth weld at a neutron fluence of 3.31E+19 n/cm^2. The 2004 fluence projections indicate that the limiting weld will experience this fluence at 38.1 EFPYs. Assuming a long-term capacity factor of 95%, this fluence would be achieved late in 2017.

The PBNP Reactor Vessel Surveillance Program includes a flux reduction program to manage the Unit 2 RPV intermediate-to-lower shell girth weld PTS issue for the period of extended operation in accordance with 10 CFR 50.61(b)(3).

The current PBNP flux reduction actions will not prevent the intermediate-to-lower shell girth weld on Unit 2 from exceeding the PTS screening criteria at EOLE. The PBNP Reactor Vessel Surveillance Program will include other options to manage Reactor Vessel Integrity per 10 CFR 50.61. These options will include consideration of an alternate fracture toughness evaluation methodology, pursuit of an aggressive flux reduction program in the future, pursuit of risk analysis, or pursuit of RPV annealing. Each of these options can provide technically acceptable methods of achieving EOLE with the PBNP RPVs.

The Reactor Vessel Surveillance Program will provide reasonable assurance that the Unit 2 RPV intermediate-to-lower shell girth weld PTS issue will be adequately managed for the period of extended operation in accordance with 10 CFR 50.61, per 10 CFR 54.21(c)(1)(iii).

The analysis associated with pressurized thermal shock has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

2.1.3.2 Technical Evaluation

2.1.3.2.1 Background

The Point Beach License Renewal SER, NUREG-1839, discusses the reactor vessel pressurized thermal shock evaluation in Sections 3.0.3.2.17, Reactor Vessel Surveillance Program; 3.1.2.2.3, Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Section 4.2, Reactor Vessel Irradiation Embrittlement. The commitments made under the license renewal SER related to reactor vessel irradiation embrittlement and pressurized thermal shock are contained in Appendix A to NUREG-1839.

Reactor vessel integrity is potentially impacted by any changes in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the proposed EPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the Unit 1 end of license extension (EOLE, 53 EFPY) and Unit 2 end of life (EOL, 35.9 EFPY) PTS evaluation.

2.1.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The calculated (projected) fluence on the vessel was evaluated for the impact of the proposed EPU on the reactor vessel integrity evaluations. These fluence projections for various effective full-power years (EFPY) are presented in Table 2.1.1-1, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 1, and Table 2.1.1-2, Maximum Neutron Exposure of Pressure Vessel Beltline Materials for Point Beach Unit 2. Updated surveillance capsule fluence values are provided in Table 2.1.1-3, Calculated Integrated Neutron Exposure of the Point Beach Units 1 and 2 Surveillance Capsules.

Typically, fluence values are used to calculate the EOL or EOLE transition temperature shift (EOL or EOLE RT_{PTS}) in the PTS equation from 10 CFR Part 50.61. All of the neutron exposure evaluations for PBNP Units 1 and 2 used the NRC approved methodology described in Reference 2. This approved methodology follows the guidance and meets the requirements of Regulatory Guide 1.190 (Reference 3).

The chemistry factors (CF) and fluence factors (FF) are used to determine the ΔRT_{PTS}. The CF values used in this evaluation are presented in Table 2.1.3-1, Summary of Point Beach Units 1 and 2 Material Chemistry Factor Values Based on Regulatory Guide 1.99, Revision 2, Position 1.1 and Position 2.1[a], and are documented in WCAP-15976 Revision 1 (Reference 4). Note that WCAP-15976 Revision 1 also contains the copper and nickel weight percent values that were used to calculate the chemistry factor values.

The initial RT_{NDT} values are the baseline reference temperature for each material and were used (along with the ΔRT_{PTS} and margin) to determine the EOL and EOLE RT_{PTS}. The initial RT_{NDT} values used in this evaluation are presented in Table 2.1.3-1, Summary of Point Beach Units 1 and 2 Material Chemistry Factor Values Based on Regulatory Guide 1.99, Revision 2, Position 1.1 and Position 2.1[a], and are also documented in WCAP-15976 Revision 1 (Reference 4).

The temperature at which the surveillance capsule specimens and the reactor vessel materials below the inlet nozzles are irradiated is equal to the reactor vessel inlet temperature (T_{COLD}). Irradiation temperature is an important variable in consideration of the degree of embrittlement and use of the embrittlement correlations in Regulatory Guide 1.99, Revision 2.

Assumptions

Reactor vessel materials which accumulate a fluence of 1×10^{17} n/cm^2 (E > 1.0 MeV) or greater at 53 EFPY for Unit 1 and 35.9 EFPY for Unit 2 are considered in this analysis. For the purpose of the fluence analysis, the hafnium peripheral power suppression assembly (PPSA) removal date is assumed to be November 2008 for Unit 1 and October 2009 for Unit 2. The EPU implementation date is assumed to be April 2010 for Unit 1 and October 2009 for Unit 2. The actual hafnium removal dates and EPU implementation dates may differ from those that were assumed. However, the assumed hafnium removal dates and EPU implementation dates are conservative for the purpose of the analysis.

Acceptance Criteria

The EPU RT_{PTS} values for all beltline materials must not exceed the screening criteria of the PTS Rule for EOL. Specifically, the RT_{PTS} values of the base metal (plates or forgings) and longitudinal welds must not exceed 270°F, while the circumferential weld RT_{PTS} values must not exceed 300°F through the EOLE of 53 EFPY for PBNP Unit 1 or the EOL of 35.9 EFPY for PBNP Unit 2.

For T_{COLD}, the acceptance criteria are provided in Regulatory Guide 1.99, Revision 2, Position 1.3, which states that, 'The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement.' Thus, T_{COLD} must be greater than 525°F and less than 590°F for the equations and methodology of Regulatory Guide 1.99, Revision 2 (which is the basis for 10 CFR Part 50.61) to remain valid.

2.1.3.2.3 Description of Analyses and Evaluations

The limiting condition on reactor vessel integrity known as PTS can occur during a severe system transient such as a loss-of-coolant accident (LOCA) or a steam line break. Such transients can challenge the integrity of a reactor vessel under the following conditions:

- Severe overcooling of the inside surface of the vessel wall followed by high repressurization
- Significant degradation of vessel material toughness caused by radiation embrittlement
- Presence of a critical-size defect in the vessel wall

The PTS concern arises if one of these transients should act on the beltline region of a reactor vessel where a reduced fracture resistance exists because of neutron irradiation. Such an event could produce the propagation of flaws postulated to exist near the inner wall surface, thereby potentially affecting the integrity of the vessel.

In 1985, the NRC issued a formal rule on PTS. It established screening criteria on pressurized water reactor (PWR) vessel embrittlement as measured by the RT_{PTS}. RT_{PTS} screening criteria values were set (using conservative fracture mechanics analysis techniques) for beltline axial welds, plates, forgings, and beltline circumferential weld seams for end of life plant operation. All PWR vessels in the U.S. have been required to evaluate vessel embrittlement in accordance with the criteria through end of life.

The NRC subsequently amended its regulations for light water reactors (LWRs) changing the procedure for calculating radiation embrittlement. The revised PTS rule was published in the Federal Register, December 19, 1995, with an effective date of January 18, 1996. This amendment made the procedure for calculating RT_{PTS} values consistent with the methods given in Regulatory Guide 1.99, Revision 2.

The PTS rule establishes the following requirements for all domestic, operating PWRs:

- For each PWR that has had an operating license issued, the licensee will have projected values of RT_{PTS} accepted by the NRC, for each reactor vessel beltline material for the end of life fluence of the material.
- The assessment of RT_{PTS} must use the calculation procedures given in the PTS Rule and must specify the bases for the projected value of RT_{PTS} for each beltline material. The report must specify the copper and nickel contents and the fluence values used in the calculation for each beltline material.
- This assessment must be updated whenever there is a significant change in projected values of RT_{PTS}, or upon the request for a change in the expiration date for operation of the facility. Changes to RT_{PTS} values are significant if either the previous value or the current value, or both values, exceed the screening criterion prior to the expiration of the operating license, including any license renewal term, if applicable for the plant.
- The RT_{PTS} screening criteria values for the beltline region are:
  - 270°F for plates, forgings, and axial weld materials
  - 300°F for circumferential weld materials
- RT_{PTS} must be calculated for each vessel beltline material using a fluence value, f, which is the end of life fluence for the material. Equation 1 is used to calculate values of RT_{NDT} for each weld and plate or forging in the reactor vessel beltline.

$$RT_{NDT} = RT_{NDT(U)} + M + \Delta RT_{NDT} \qquad \text{Equation 1}$$

Where,

$RT_{NDT(U)}$ = Reference temperature for a reactor vessel material in the pre-service or unirradiated condition

M = Margin to be added to account for uncertainties in the values of $RT_{NDT(U)}$, copper and nickel contents, fluence and calculational procedures. M was evaluated from the Equation 2.

$$M = 2\sqrt{\sigma_i^2 + \sigma_\Delta^2} \qquad \text{Equation 2}$$

σ_i is the standard deviation for $RT_{NDT(U)}$.
σ_Δ is the standard deviation for RT_{NDT}.

For plates and forgings: ($\sigma\Delta$ not to exceed one half of ΔRT_{NDT})

$\sigma\Delta$ = 17°F when surveillance capsule data are not used

$\sigma\Delta$ = 8.5°F when surveillance capsule data are used

For welds: ($\sigma\Delta$ not to exceed one half of ΔRT_{NDT})

$\sigma\Delta$ = 28°F when surveillance capsule data are not used

$\sigma\Delta$ = 14°F when surveillance capsule data are used

ΔRT_{NDT} is the mean value of the transition temperature shift, or ΔRT_{PTS}, due to irradiation, and was calculated using Equation 3.

$$\Delta RT_{NDT} = (CF)^*f^{(0.28 - 0.10 \log f)} \qquad \text{Equation 3}$$

CF (°F) is the chemistry factor, which is a function of copper and nickel content. CF was determined from Tables 1 and 2 of the PTS Rule. Surveillance data deemed credible is used to determine a material-specific value of CF. A material-specific value of CF is determined in Equation 5.

f is the calculated neutron fluence, in units of 10^{19} n/cm^2 (E > 1.0 MeV), at the clad-base-metal interface on the inside surface of the vessel at the location where the material in question receives the highest fluence. The 53 EFPY EOLE fluence projections were used in calculating the PBNP Unit 1 RT_{PTS}. The 35.9 EFPY EOL fluence projections were used in calculating the PBNP Unit 2 RT_{PTS}.

Equation 4 is used for determining RT_{PTS} using Equation 3 with end of life fluence values for determining RT_{PTS}

$$RT_{PTS} = RT_{NDT(U)} + M + \Delta RT_{PTS} \qquad \text{Equation 4}$$

To verify that RT_{NDT} for each vessel beltline material is a bounding value for the specific reactor vessel, plant-specific information that could affect the level of embrittlement is considered. For the PBNP calculation this information included, but was not limited to, the reactor vessel operating temperature and any related surveillance program results. Results from the plant-specific surveillance program are integrated into the RT_{PTS} estimate if the plant-specific surveillance data is deemed credible. Material-specific values of CF for surveillance materials are determined from Equation 5.

$$CF = \frac{\sum[A_i{}^*f_i^{(0.28 - 0.10 \log f_i)}]}{\sum[f_i^{(0.56 - 0.20 \log f_i)}]} \qquad \text{Equation 5}$$

In Equation 5, "A_i" is the measured value of ΔRT_{NDT} and "f_i" is the fluence for each surveillance data point. If there is clear evidence that the copper and nickel content of the surveillance weld differed from the vessel weld, i.e., differed from the average for the weld wire heat number associated with the vessel weld and the surveillance weld, the measured values of RT_{NDT} would be adjusted for differences in copper and nickel content by multiplying them by the ratio of the CF for the vessel material to that for the surveillance weld.

RT_{PTS} values for the PBNP Unit 1 reactor vessel beltline materials with fluence values (E > 1.0 MeV) at 53 EFPY are presented in Table 2.1.3-2, RT_{PTS} Calculations for Point Beach Unit 1 Beltline Region Materials at 53 EFPY. RT_{PTS} for the PBNP Unit 2 reactor vessel beltline materials with fluence values (E > 1.0 MeV) at 35.9 EFPY are presented in Table 2.1.3-3, RT_{PTS} Calculations for Point Beach Unit 2 Beltline Region Materials at 35.9 EFPY.

2.1.3.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached in the Point Beach License Renewal SER (NUREG-1839) Section 4.2 for PTS analysis of all the beltline materials. The aging evaluations approved by the NRC in NUREG-1839 for the beltline materials with respect to PTS remain valid for EPU conditions.

2.1.3.3 Results

An evaluation of the impact of the EPU on PTS was performed for PBNP. PTS calculations were performed for all the beltline materials of the PBNP reactor vessel under EPU conditions using the rules from 10 CFR Part 50.61. The results of these calculations are presented in Table 2.1.3-2, RT_{PTS} Calculations for Point Beach Unit 1 Beltline Region Materials at 53 EFPY, and Table 2.1.3-3, RT_{PTS} Calculations for Point Beach Unit 2 Beltline Region Materials at 35.9 EFPY. The limiting material for PBNP Unit 1 at EOLE (53 EFPY) is the intermediate to lower shell circumferential weld. At 53 EFPY, the PBNP Unit 1 limiting value of RT_{PTS} is 297.8°F. At 35.9 EFPY (EOL) the PBNP Unit 2 limiting value is the intermediate shell to lower shell circumferential weld with an RT_{PTS} of 295.1°F. Both of these results are below the RT_{PTS} screening criteria of 300°F. Based on these results, all RT_{PTS} values remained below the NRC screening criteria using the projected EPU fluence projections through EOLE (53 EFPY) for PBNP Unit 1 and through EOL (35.9 EFPY) for PBNP Unit 2.

2.1.3.4 Conclusions

PBNP has reviewed the evaluation of the effects of the proposed EPU on the PTS for the plant and concludes that it has adequately addressed changes in neutron fluence and their effects on PTS through 53 EFPY for Unit 1 and 35.9 EFPY for Unit 2. PBNP further concludes that the evaluation has demonstrated that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 34 and 36, following implementation of the proposed EPU to 53 EFPY for Unit 1 and 35.9 EFPY for Unit 2.

2.1.3.5 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301, December 2005

2. WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006

3. Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001

4. WCAP-15976, Revision 1, Point Beach Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation, March 2008

Table 2.1.3-1 Summary of Point Beach Units 1 and 2 Material Chemistry Factor Values Based on Regulatory Guide 1.99, Revision 2, Position 1.1 and Position 2.1[a]

Material Description	Material Identification	Chemistry Factor		Initial RT_{NDT}
		Position 1.1	Position 2.1	
Point Beach Unit 1				
Nozzle Belt Forging (NB)	122P237	77°F	---	50°F[b]
Intermediate Shell (IS)	A9811-1	88°F	79.3°F	1°F[b]
Lower Shell (LS)	C1423-1	55.3°F	35.8°F	1°F[b]
NB to IS Circ. Weld	SA-1426	152.4°F	---	-5°F[c]
IS Long. Weld (ID 27%)	SA-812	138.2°F	---	-5°F[c]
IS Long. Weld (OD 73%)	SA-775	157.6°F	---	-5°F[c]
IS to LS Circ. Weld	SA-1101	167.6°F	---	10°F[β]
LS Long. Weld	SA-847	157.4°F	163.3°F	-5°F[c]
Point Beach Unit 2				
Nozzle Belt Forging (NB)	123V352	76°F	---	40°F[b]
Intermediate Shell (IS)	123V500	58°F	---	40°F[b]
Lower Shell (LS)	122W195	31°F	43°F	40°F[b]
NB to IS Circ. Weld	21935	170°F	---	-56°F[c]
IS to LS Circ. Weld	SA-1484	180°F	---	-5°F[c]

Notes:

a. All values taken from WCAP-15976-NP, Revision 1 (Reference 4).
b. Initial RT_{NDT} value is measured.
c. Initial RT_{NDT} value is generic.

Table 2.1.3-2 RT_{PTS} Calculations for Point Beach Unit 1 Beltline Region Materials at 53 EFPY

Material	Fluence, f (10^{19} n/cm^2, E > 1.0 MeV)	FF[(a)]	CF (°F)	ΔRT_{PTS} (°F)[(b)]	σ^1 (°F)	σ_Δ (°F)	Margin (°F)[(c)]	$RT_{NDT(U)}$ (°F)	RT_{PTS} (°F)[(d)]
Nozzle Belt Forging (NB)	0.383	0.73	77.0	56.6	0	17	34.0	50	140.5
Intermediate Shell (IS)	5.09	1.41	88.0	123.7	26.9	17	63.6	1	188.4
Intermediate Shell (IS) Using surveillance data	5.09	1.41	79.3	111.5	26.9	8.5	56.4	1	168.9
Lower Shell (LS)	4.65	1.39	55.3	76.8	26.9	17	63.6	1	141.4
Lower Shell (LS) Using surveillance data	4.65	1.39	35.8	49.7	26.9	8.5	56.4	1	107.1
NB to IS Circ. Weld	0.383	0.73	152.4	111.9	19.7	28	68.5	-5	175.4
IS Long. Weld (ID 27%)	3.33	1.32	138.2	181.8	19.7	28	68.5	-5	245.2
IS to LS Circ. Weld	4.54	1.38	167.6	231.8	0	28	56.0	10	297.8
LS Long. Weld	3.14	1.30	157.4	204.9	19.7	28	68.5	-5	268.3
LS Long. Weld Using surveillance data	3.14	1.30	163.3	212.3	19.7	14	48.3	-5	255.9

Notes:

a. $FF = f^{(.28 - 0.1*\log f)}$, where f is the clad/base metal interface fluence.

b. $\Delta RT_{PTS} = CF * FF$.

c. $Margin = 2*(\sigma_i^2 + \sigma_\Delta^2)^{1/2}$.

d. $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS} + Margin$ (°F).

Table 2.1.3-3 RT_{PTS} Calculations for Point Beach Unit 2 Beltline Region Materials at 35.9 EFPY

Material	Fluence, f (10^{19} n/cm², E > 1.0 MeV)	FF[(a)]	CF (°F)	ΔRT_{PTS} (°F)[(b)]	σ^1 (°F)	σ_Δ (°F)	Margin (°F)[(c)]	$RT_{NDT(U)}$ (°F)	RT_{PTS} (°F)[(d)]
Nozzle Belt Forging (NB)	0.323	0.689	76	52.4	0	17	34	40	126.4
Intermediate Shell (IS)	3.32	1.31	58	76.2	0	17	34	40	150.2
Lower Shell (LS)	3.14	1.30	31	40.3	0	17	34	40	114.3
Lower Shell (LS) Using surveillance data	3.14	1.30	43	56.0	0	8.5	17	40	113.0
NB to IS Circ. Weld	0.323	0.689	170	117.2	17	28	65.5	-56	126.7
IS to LS Circ. Weld	2.95	1.29	180	231.6	19.7	28	68.5	-5	295.1

Notes:

a. $FF = f^{(.28 - 0.1*\log f)}$, where f is the clad/base metal interface fluence.

b. $\Delta RT_{PTS} = CF * FF$.

c. $Margin = 2*(\sigma_i^2 + \sigma_\Delta^2)^{1/2}$.

d. $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS} + Margin$ (°F).

2.1.4 Reactor Internals and Core Support Materials

2.1.4.1 Regulatory Evaluation

The reactor internals and core supports include structures, systems, and components that perform safety functions or whose failure could affect safety functions performed by other structures, systems, and components. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant system). PBNP considered materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internals 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, WCAP-14577 and BAW-2248.

PBNP Current Licensing Basis

The reactor vessel internals (RVIs), consisting of the lower core support structure, upper core support assembly, in-core instrumentation support structures, core barrel and thermal shield, are designed to support, align, and guide the core components, direct the coolant flow to and from the core components, and to support and guide the in core instrumentation.

The PBNP RVIs consist of two basic assemblies:

- Upper internals assembly that is removed during each refueling operation to obtain access to the reactor core. The top of this assembly is clamped to a ledge below the vessel-head mating surface by the reactor vessel head. The core barrel alignment pins of the lower internals assembly guides the bottom of the upper internals assembly.
- Lower internals assembly that can be removed, if desired, following a complete core offload. This assembly is clamped at the same ledge below the vessel-head mating surface and closely guided at the bottom by radial/clevis assemblies.

Subcomponents included for evaluation with the RVI include support columns and plates, core barrel, baffle former assembly and bolting, instrument and control guides and supports.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 1 is as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

FSAR Section 15.2.17 describes the Reactor Vessel Internals Program. The Reactor Vessel Internals Program manages the aging effects for reactor vessel internals (RVI). The program provides for (a) Inservice Inspection (ISI) in accordance with ASME Section XI requirements, including examinations performed during the 10-year ISI examination; (b) An evaluation that will identify leading locations with respect to IASCC and irradiation embrittlement, appropriate non-destructive examination techniques, and an examination schedule for these locations; (c) Baffle-former/barrel-former bolt evaluation that will determine the acceptability of the current arrangement or if ultrasonic examination and/or replacement of these bolts is necessary; (d) For cast austenitic stainless steel components subject to neutron fluence in excess of 1E17 n/cm^2 or determined to be susceptible to thermal embrittlement, an augmented inspection of components experiencing significant tensile stress (>5 ksi); (e) Evaluation of the significance of void swelling; (f) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Control Program to mitigate Storage Corrosion Cracking (SCC) or Irradiation-Assisted Stress Corrosion Cracking (IASCC); (g) Participation in industry initiatives that will generate additional data on aging mechanisms relevant to Reactor Vessel Interna (RVI) and develop appropriate inspection techniques to permit detection and characterization of features of interest; and (h) One-time inspection of the internals hold-down spring for evidence of stress relaxation.

The adequacy of the PBNP reactor vessel internals and core support materials relative to conformance to the PBNP specific general design criteria (GDC) are described in FSAR Chapter 1 Sections 1.3.1, Overall Plant Requirements, 1.3.2, Protection by Multiple Fission Product Barriers, 1.4, Quality Assurance Program, Chapter 3 Sections 3.1.2, Principle Design Criteria, 3.1.3, Safety Limits, 3.2.3, Mechanical Design and Evaluation, Chapter 4 Sections 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 4.4, Tests and Inspections and Chapter 15 Section 15.2.17, Reactor Vessel Internals Program.

The PBNP RVIs were evaluated for plant license renewal. The Westinghouse Owner's Group (WOG) submitted Topical Report, WCAP-14577, Rev 1-A, License Renewal Evaluation: Aging Management for Reactor Internals (Reference 8), to the NRC in September 1997 for review and approval. The report provided a technical evaluation of the effects of aging of the Reactor Vessel Internals (RVI) and generically demonstrated how aging management options maintain the intended functions of the RVI and how these options would remain effective during the period of extended operation.

The NRC found the generic topical report (GTR) acceptable, as documented in a final safety evaluation report (FSER) transmitted to the WOG in February 2001. The PBNP RVIs were included in the Westinghouse Nuclear Steam Supply System (NSSS) scope of supply and were designed, fabricated and installed in accordance with Westinghouse Equipment Specifications. Therefore, the PBNP RVI components were designed, fabricated and installed to a configuration similar to that specified in the GTR. The design parameters associated with the PBNP RVI components and the operational environment are bounded by those that are considered in the GTR. The PBNP RVI components requiring aging management reviews performed the same intended functions as those in the GTR.

The results and conclusions in the GTR with respect to aging mechanisms and effects are applicable to the PBNP RVIs that need to be managed in period of extended operation.

The GTR identifies fatigue as the only aging mechanism related to the RVIs that satisfies the Time Limiting Aging Analysis (TLAA) criteria in 10 CFR 54. However, not all RVI components are sensitive to fatigue.

Aging management program elements are identified in the GTR. Specific PBNP program details to manage the aging mechanisms and effects are identified in FSAR Section 15.2.17, Reactor Vessel Internals Program, 15.2.23, Thimble Tube Inspection Program, and 15.2.24, Water Chemistry Control Program. These PBNP specific programs also satisfy the program elements that are identified in the GTR, with the exception of loose parts monitoring, and neutron noise monitoring. On-line loose parts monitoring, and on-demand neutron noise monitoring are not being credited for aging management.

The NRC reviewed PBNP's License Renewal Application, the supporting information in the FSAR and PBNP's responses to the License Renewal RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant and concluded that no omissions could be identified. On the basis of this review, the NRC concluded that PBNP has appropriately identified those portions of the reactor vessel and its associated (supporting) SSCs that are within the scope of License Renewal, as required by 10 CFR 54.5(a), and that PBNP has appropriately identified those portions of the reactor vessel and its associated (supporting) SSCs that are subject to aging management review, as required by 10 CFR 54.21(a)(1).

2.1.4.2 Technical Evaluation

2.1.4.2.1 Introduction

This section of the report summarizes the evaluations, and their results, of the potential materials degradation issues arising from the effect of extended power uprate (EPU) on the performance of reactor internals and core support materials at PBNP.

The Westinghouse Owners' Group (WOG) Life Cycle Management & License Renewal Program prepared the topical report WCAP–14577, Rev 1-A, License Renewal Evaluation: Aging Management for Reactor Internals (Reference 8). The topical report describes the aging degradation mechanisms to determine the aging effects. All identified effects are evaluated to identify potential degradation of RVI intended functions. The evaluation also included the time-limited aging analyses (TLAAs). All effects and TLAAs that require management during

EPU operation are identified in the report. The report has been used in the NRC aging management review of the PBNP RVI components.

The NRC review of the WOG topical report concluded that the report provides an acceptable demonstration that the applicable effects of aging on reactor vessel internals components will be adequately managed for the WOG plants, such that there is a reasonable assurance that the RVI components will perform their intended functions in accordance with the current licensing basis. The EPU evaluation considered potential changes in the aging effects due to the change in the service conditions resulting from the proposed EPU conditions. These are considered below:

The primary objective of the EPU assessment was to ensure that the new EPU environmental conditions (chemistry, temperature, and fluence) will neither introduce any new aging effects on the RVI components during years 40-60, nor change the manner in which the component aging will be managed by the aging management program credited in the topical report WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), and accepted by the NRC in the Safety Evaluation Report (SER).

The relevant potentially impacted degradation (aging) mechanisms are:

A. Fuel cladding corrosion effects

B. Intergranular and Transgranular Stress Corrosion Cracking (IGSCC & TGSCC) of austenitic stainless steel materials

C. Primary water stress corrosion cracking (PWSCC) of Alloy 600 and Alloy X-750 components

D. Irradiation assisted stress corrosion cracking (IASCC) and void swelling of austenitic steel material internals

E. Radiation induced excessive heating rates of RVI components

F. Thermal growth of RVI components

G. Thermal aging embrittlement of RVI cast austenitic stainless steel (CASS) components

An assessment of these aging mechanisms is considered in the following subsections.

2.1.4.2.2 Input Parameters

Proposed EPU Service Conditions

A review of the EPU design parameters (LR Section 1.1, Nuclear Steam Supply System Parameters and Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate) indicates that the following changes in service condition will occur as a result of the proposed EPU implementation:

- The reactor coolant lithium/boron chemistry management program is coordinated such that the pH value is maintained at levels between 7.4 and 6.9 while the Lithium levels are maintained between 2.35 and 2.05 ppm for the 18 month cycle (Reference 1 and Reference 2)

The maximum fast neutron fluence (E > 1.0 MeV) on the PBNP Units 1 and 2 baffle plates following implementation of the EPU has been calculated and is summarized below:

	Unit 1	**Unit 2**
1.5 EFPY	2.30E+21 n/cm^2	2.40E+21 n/cm^2
32.0 EFPY	4.67E+22 n/cm^2	4.61E+22 n/cm^2
54.0 EFPY	8.83E+22 n/cm^2	8.77E+22 n/cm^2

The corresponding neutron fluence (E > 0.1 MeV) is as follows:

	Unit 1	**Unit 2**
1.5 EFPY	4.91E+21 n/cm^2	5.11E+21 n/cm^2
32.0 EFPY	9.90E+22 n/cm^2	9.75E+22 n/cm^2
54.0 EFPY	1.91E+23 n/cm^2	1.85E+23 n/cm^2

These maximum exposures occur on the inside surface of the baffle plates opposite the central sections of the reactor core.

2.1.4.2.3 Description of Analyses and Evaluations

The effect of changes in service conditions due to the proposed EPU on the performance of the reactor vessel internals materials is discussed in the following paragraphs.

Materials Specifications, Weld Controls and NDT Inspections

The NRC Staff's acceptance criteria for reactor internals 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. PBNP's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. Specific review criteria are contained in SRP Section 4.5.2, WCAP-14577 (Reference 8) and BAW-2248 (Reference 9).

A. Fuel-Cladding Corrosion Effects

The proposed PBNP EPU lithium, boron, and pH management program based on an 18 month cycle (Reference 1 and Reference 2) suggested operating at pH levels between 7.4 and 6.9 while the Lithium level is maintained between 2.35 and 2.05 ppm. These conditions are identical to current operating parameters and are bounded by the proposed Electric Power Research Institute (EPRI) chemistry guidelines (Reference 3). Since these guidelines are specifically designed to prevent fuel-cladding corrosion effects, such as fuel deposit buildup, and they do not vary from current parameters there will be no adverse effect on fuel cladding corrosion.

B. Stress Corrosion Cracking

The two degradation mechanisms that are operative in the internals austenitic stainless steels are Inter-granular Stress Corrosion Cracking (IGSCC) and Transgranular Stress Corrosion

Cracking (TGSCC). Susceptible materials, sensitized microstructure, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The principal method of preventing IGSCC and TGSCC is by water chemistry control. Westinghouse specifies that the reactor coolant chemistry be rigorously controlled, particularly with regard to oxygen, chlorides and other halogens. PBNP controls reactor coolant chemistry through a monitoring program (Reference 1). Ingress from other species, such as demineralizer resins, is carefully monitored, and corrective actions are taken to preclude exposure. In addition, startup transient oxygen levels are minimized such that oxygen controls are established prior to elevated temperature operation.

C. Primary Water Stress Corrosion Cracking

Primary water stress corrosion cracking (PWSCC) is another form of IGSCC degradation that has been observed in Alloy 600 and Alloy X-750 materials in PWR applications. Clevis insert bolts at PBNP are fabricated from X-750 material; the clevis inserts and clevis insert lock keys are manufactured from Alloy 600 material. The X-750 guide tube support pins and nuts at PBNP Unit 1 and Unit 2 have been replaced with PWSCC resistant TP 316 Strain Hardened stainless.

The PBNP Units 1 and 2 have implemented an Alloy 600 management program to address the PWSCC issue. The program included an assessment of PWSCC susceptibility and an evaluation of mitigative and repair options at the Alloy 600 pressure boundary locations.

The cracking of X-750 material is attributed to a combination of high stress and undesirable microstructure. Both Unit 1 and Unit 2 split pins were replaced with PWSCC resistant TP 316 Strain Hardened stainless steel.

The Alloy 600 clevis inserts experience lower fluence, temperature, and stresses in comparison to the support pins. The clevis inserts experience essentially compressive stress and no failures have been reported. Furthermore, like the clevis insert bolts, a failure of the clevis inserts would not result in a loss of intended function due to the nature of the design. Therefore, the effects of PWSCC on the clevis inserts are not considered significant.

The topical report WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), considered the potential SCC degradation and concluded that the effects of all forms of SCC are not significant for Alloy 600, X-750, and stainless steel RVI components. The NRC review of the topical report concluded that there is a reasonable assurance that the RVI components will perform their intended functions in accordance with the current licensing basis during the period of extended operation.

The proposed EPU chemistry program at PBNP suggested operating at pH levels between 7.4 and 6.9 while the Lithium level is maintained between 2.35 and 2.05 ppm. The chemistry program used for operation in the EPU condition does not involve introduction of any of the (stress, oxygen or halogen) contributors. Therefore no impact on the stress corrosion cracking material degradation is expected in the RVI components as a result of the EPU.

D. Irradiation-Assisted Stress Corrosion Cracking

Irradiation-assisted embrittlement is possible in the reactor internals components fabricated from austenitic stainless steel and nickel-based alloys with expected neutron fluences in excess of 1×10^{21} n/cm^2 (E > 0.1 MeV). If the expected neutron fluence is less than approximately 1×10^{21} n/cm^2 (E > 0.1 MeV), then the changes in mechanical properties due to neutron exposure are insignificant. The reactor internals components with fluences greater than 1×10^{21} n/cm^2 (E > 0.1 MeV) (e.g., lower core barrel, baffle/former assembly, baffle/former bolts, lower core plate and fuel pins, lower support forging, clevis bolts) are potentially susceptible to irradiation-assisted embrittlement.

The EPU expected maximum fast neutron (E > 0.1 MeV) exposure levels of the PBNP reactor internals for operating periods of 32 and 54 effective full power years (EFPY) are listed in Section 2.1.4.2.2, Reactor Internal and Core Support Materials - Input Parameters. These values are consistent with the values reported in Section 3.1.1.2 of the License Renewal Application (LRA) topical report. Section B2.1.27 of the LRA identifies the following RVI components as being exposed to the highest in-core neutron radiation fields and hence most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling.

- Lower core plate and fuel alignment pins
- Lower support columns
- Core barrel and core barrel flange in active core region
- Thermal shield
- Bolting-lower support column, baffle-former, and barrel-former

Data from power reactor irradiation of Type 304 and Type 316 stainless steel are available from several studies (Reference 4, Reference 5 and Reference 6). Embrittlement, as evidenced by increases in yield strength and decreases in uniform and total elongation, is common in these materials after irradiation. Studies (Reference 2 and Reference 3) showed that embrittlement of stainless steel can occur at fluences as low as 1×10^{21} n/cm^2 (E > 0.1 MeV) in the more susceptible stainless steel materials such as 304SS. These same studies showed that the rate of change in mechanical properties is reduced at fluences above 2×10^{22} n/cm^2 (E > 0.1 MeV).

No instance of service related internals degradation has been recorded that can be directly attributed to irradiation embrittlement. However, the end-of-life fluence level for some internals components is estimated at 1.91×10^{23} n/cm^2 (E > 0.1 MeV), therefore PBNP will continue to participate in the industry Materials Reliability Program/Issues Task Group efforts on reactor internals and monitor developments in this area.

The NRC's review (PBNP License Renewal SER) concluded that PBNP's Generic Aging Lessons Learned (GALL) process identified in the LRA is consistent with the GALL Report (NUREG-1801,Reference 10) and that PBNP has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

E. Radiation Induced Heat Generation (Gamma Heating)

The presence of radiation-induced heat generation rates in the reactor internals components, in conjunction with the reactor coolant fluid temperatures, results in thermal gradients within and between the components. The resultant material temperature gradients cause thermal stresses and thermal growth that must be considered in the design and analysis of various components. The reactor internals components subjected to significant radiation-induced heat generation are core baffle plates, former plates, core barrel, baffle-former bolts, barrel-former bolts, thermal shield, and the upper and lower core plates.

The results of the radiation-induced heat generation rate evaluations at the power uprated condition for PBNP Units 1 and 2 showed that for all of the radial components, (baffle and former panels, the core barrel, and thermal shields) significant margin exists between the current calculations and the design values (Reference 7).

F. Void Swelling

Void swelling is defined as the gradual increase in size (physical dimension) of the RVI stainless steel component caused by the formation and growth of helium-vacancy clusters into voids due to the effect of irradiation. Although the effects of swelling can be potentially significant for those components which experience significant neutron irradiation while operating at elevated temperatures, the actual plant operations do not appear to produce the conditions necessary for significant swelling. Data from PBNP and Farley nuclear plants suggested very small (0.01% to 0.03%) amounts of swelling in baffle bolts. Extrapolation of these data using a simple square law suggests no concern with respect to void swelling until the end of extended life in U.S. PWRs. Fuel management schemes to reduce neutron leakage from the core have reduced one of the major factors contributing to swelling, and mechanisms such as creep and stress relaxation serve to reduce some of the adverse effects. The topical report WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), examined the effects of swelling and concluded that any actual swelling of the susceptible internals will not prevent them from performing their intended function during the license renewal period.

Industry data on swelling were evaluated as part of the WOG and Materials Reliability Program (MRP). At present there have been no indications from the different bolt removal programs or functional 'evaluations' that there are any discernible effects attributable to swelling. PBNP will continue to participate and follow these industry efforts to investigate swelling effects on the reactor vessel internals and use this information to enhance the program for inspection of the reactor internals and core support materials.

G. Thermal Aging

Thermal aging of cast stainless steel can lead to precipitation of additional phases in the ferrite and growth of existing carbides at the ferrite/austenitic boundaries that can result in loss of ductility and fracture toughness of the material. The susceptibility to thermal aging is a function of the material chemistry, aging temperature, and time at temperature. All the cast duplex stainless steel reactor internals in the Westinghouse-designed NSSS are made from CF-8 or

CF-8A materials which contain low or zero Molybdenum and are less susceptible to thermal aging.

At PBNP the lower core support column bodies, lower support casting, Bottom-Mounted Instrumentation (BMI) column cruciforms, upper support column bases, flow mixing devices, and lower and intermediate flanges are potentially fabricated from CF8 cast austenitic stainless steel material. Although these components are potentially susceptible to thermal aging embrittlement under prolonged exposure to elevated temperatures, the chemistry content and the service temperatures (354°F–611°F) at EPU conditions are not favorable to produce significant loss of toughness. Therefore, EPU is not expected to have any significant impact on the structural integrity of cast stainless steel of the reactor internals or core support materials.

The topical report WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), conducted an evaluation of the effects of thermal aging and concluded that the effects of thermal aging are insignificant to all of the reactor internals components and aging management of this effect will not be required during an extended period of operation.

2.1.4.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In the PBNP application for Operating License Renewal, the RV Internals materials of construction and likely aging effects were identified along with effective aging management programs. In support of its aging management programs, PBNP referenced topical report WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), which had been previously reviewed and approved by NRC.

Following a detailed review of the PBNP aging management programs, and confirming the applicability of WCAP-14577, Rev. 1-A (Reference 8), the NRC summarized its conclusions in NUREG-1839, the Safety Evaluation Report (SER) Related to the License Renewal of PBNP Units 1 and 2, December 2005.

In Section 3.1.3 of NUREG-1839, the staff concluded that the aging effects associated with the RCS components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The effects of the proposed EPU will not significantly change the set of aging effects identified in the license renewal aging evaluations nor the effectiveness of the identified license renewal aging management programs that were reviewed and found acceptable by the NRC staff.

2.1.4.2.5 Results

The results of the reactor vessel internals material degradation assessment showed that no materials degradation issues will result from the proposed power uprate at PBNP. On this basis it is concluded that the new EPU environmental conditions (chemistry, temperature, and fluence) will not introduce any new aging effects on their components during 60 years of operation, nor will the EPU change the manner in which the component aging will be managed by the aging management program credited in the topical report WCAP-14577, Rev. 1-A, License Renewal

Evaluation: Aging Management for Reactor Vessel Internals (Reference 8), and accepted by the NRC in the SER.

2.1.4.3 Conclusions

PBNP has evaluated the effects of the proposed EPU on the susceptibility of reactor internals and core support materials to degradation mechanisms and concludes that it has identified appropriate degradation management programs to address the effects of changes in operating temperature, RCS chemistry and neutron fluence on the integrity of reactor internals and core support materials. PBNP further concludes that it has been demonstrated that the reactor internals and core support materials will continue to be acceptable and will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to reactor internals and core support materials.

2.1.4.4 References

1. Primary Water Chemistry Monitoring Program, NP 3.2.2, Revision 18, March 14, 2007
2. Strategic Primary Water Chemistry Optimization Plan, NP 3.2.6, Revision 2, August 8, 2007
3. EPRI TR-1002884, Volume 1, Pressurized Water Reactor Primary Water Chemistry Guidelines, Revision 5, September 2003
4. Kangilaski, M., The Effects of Neutron Radiation on Structural Materials, REIC Report No. 45, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio (June 1967)
5. Robbins, R.E., et. al., Post Irradiation Tensile Properties of Annealed and Cold Worked AIOSI–304 Stainless Steel, Trans American Nuclear Society, pp 488-489 (Nov. 1967)
6. Bloom, E.E., Mechanical Properties of Materials in Fusion Reactor First-Wall and Blanket Systems, Journal of Nuclear Materials, 85 and 86, pp 795-804 (1979)
7. WCAP-9620, Rev. 1 (Proprietary), Reactor Internals Heat Generation and Neutron Fluences, A.H. Fero, December 1983
8. WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Internals, September 1997
9. W.H. Mackay, and F.M. Gregory, Demonstration of the Management of Aging Effects for the Reactor Vessel Internals, BAW-2248, July 1997
10. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, dated September 2005

2.1.5 Reactor Coolant Pressure Boundary Materials

2.1.5.1 Regulatory Evaluation

The reactor coolant pressure boundary (RCPB) defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The PBNP evaluation of reactor coolant pressure boundary 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 reactor coolant pressure boundary materials are based on:

- 10 CFR 50.55a and GDC-1 insofar as they require that structures, systems, and components 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 4, insofar as it requires that structures, systems, and components 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
- GDC 14, insofar as it requires that the reactor coolant pressure boundary be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture
- GDC 31, insofar as it requires that the reactor coolant pressure boundary 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
- 10 CFR 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the reactor coolant pressure boundary

Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress-corrosion cracking of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01 (Reference 6), Information Notice (IN) 00-17 (Reference 7), Bulletins 01-01 (Reference 8), 02-01 (Reference 9) and 02-02 (Reference 10). Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from NRC, to Nuclear Energy Institute (NEI), dated May 19, 2000.

PBNP Current Licensing Basis

The principal components of the RCPB are Reactor Coolant System (RCS) components that include the reactor vessel, pressurizer, steam generators, reactor coolant pumps, and the essential Class 1 piping and valves. The RCS consists of two heat transfer loops connected in parallel to the reactor vessel. Each loop contains a reactor coolant pump and a steam generator.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP, GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 1, 4, 14 and 31 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice. Particular emphasis is placed on the assurance of quality of the reactor vessel to obtain material whose properties are uniformly within code specifications.

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

The Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. Fabrication of the components which constitute the pressure boundary of the Reactor Coolant System is carried out in accordance with the applicable codes at the time of fabrication.

The materials of construction of the pressure boundary of the Reactor Coolant System are protected from corrosion phenomena which might otherwise significantly reduce the system structural integrity during its service lifetime by the use of corrosion resistant materials (such as stainless steel) and by the maintenance of proper chemistry control.

System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level.

The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME . The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement.

The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fact neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation. These limits are determined in accordance with the methods of analysis and the margins of safety of Appendix G of ASME Section XI and are included in the Point Beach Pressure Temperature Limits Report (PTLR). The Low Temperature Overpressure Protection System provides protection during low temperature operations.

All pressure containing components of the Reactor Coolant System are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement.

The reactor coolant pressure boundary materials are addressed in FSAR Section 1.3.6, Reactor Coolant Pressure Boundary, Sections 3.1, Reactor, Design Basis, 3.2, Reactor Design, Sections 4.1, Reactor Coolant System, Design Basis,
4.2, RCS System Design and Operation, 4.4, Tests and Inspections, and Section 15.4, Evaluation of Timelimited Aging Analyses.

In addition to the evaluations described in the FSAR, the PBNP reactor coolant pressure boundary was evaluated for plant license renewal, which is documented in Sections 2.3.1.1, 3.1, 4.2 and 4.3 of NUREG-1839, the Safety Evaluation Report (SER) Related to the License Renewal of PBNP Units 1 and 2, December 2005 (Reference 11).

Westinghouse performed a generic aging management evaluation of Class 1 Piping and Associated Pressure Boundary Components for the Westinghouse Owners Group. This evaluation is documented in the Westinghouse Generic Topical Report (GTR) Aging Management Review for Class 1 Piping and Associated Pressure Boundary. Components, WCAP-14575-A (Reference 12). This GTR has been accepted by the U.S. NRC for use as a reference in license renewal applications. The PBNP Class 1 Piping and Associated Pressure Boundary Components are specifically included in the Westinghouse GTR, WCAP-14575-A (Reference 12). The Applicant Action Items required by the NRC final safety evaluation report on this GTR, are discussed in Table 3.1.0-1 of the License Renewal application.

The conclusions with respect to aging effects identified in the WCAP-14575-A (Reference 12), are consistent with the aging effects identified at PBNP, with exceptions noted in the license renewal application Section 3.1, Aging Management of Reactor Coolant System.

RCPB materials are further considered in LR Section 2.1.1, Reactor Vessel Material Surveillance Program, and LR Section 2.1.6, Leak-Before-Break.

2.1.5.2 Technical Evaluation

2.1.5.2.1 Introduction

This section of the report summarizes the evaluations, and their results, of the potential materials degradation issues arising from the effect of the PBNP extended power uprate (EPU) on the performance of reactor coolant pressure boundary component materials.

The EPU evaluation assessed the potential effect of changes in the Reactor Coolant System (RCS) chemistry (impurities), pH conditions, and EPU service temperatures on the integrity of primary component pressure boundary materials during service. The evaluation includes:

- An assessment of the potential effect of water chemistry changes on the i) general corrosion (wastage) of carbon steel components and ii) stress corrosion cracking (SCC) of system austenitic stainless steel materials, and the management strategy of any associated issues
- An assessment of the effect of change in the service temperature on i) primary water stress corrosion cracking (PWSCC) of Alloy 600 base metal and Alloy 82/182 weld metals and ii) thermal aging of cast stainless steel (CASS) materials, and the management strategy of any associated issues

These assessments are discussed in the following subsections.

2.1.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Proposed EPU Service Conditions

A review of the EPU design parameters (LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate) indicates that the following changes in the RCS chemistry and service temperature conditions will occur during operations after EPU implementation:

- The EPU reactor coolant lithium/boron program is coordinated such that the pH value is maintained at levels between 7.4 and 6.9 while the Lithium levels are maintained between 2.35 and 2.05 ppm for the 18 month cycle (References 1 and 2)
- The PBNP EPU will result in a maximum increase in the peak steady-state service temperatures of 5.1°F and 7.6°F at the reactor vessel closure head and hot leg locations, respectively, and a decrease in steady-state service temperature of 1.6°F at the bottom head location due to the uprating. This is summarized in Table 2.1.5-1, Summary of Service Temperature Changes in the RV Closure Head and Bottom-Mounted Instrumentation (BMI) Penetrations Due to the Proposed EPU.

Table 2.1.5-1
Summary of Service Temperature Changes in the RV Closure Head and Bottom-Mounted Instrumentation (BMI) Penetrations Due to the Proposed EPU

Core Power Level (MWt)	Location	Temperature (°F) High	Temperature (°F) Low	Maximum Change in the Steady State Peak Temperature Due to Uprating (delta T °F)
1540 (Current)	RV Upper Head Vessel Outlet (hot leg)	594.4 603.5	579.2 588.1	
1540 (Current)	BMI Penetration	544.5	528.0	
1800 (EPU)	RV Upper Head Hot Leg	599.5 611.1	580.2 592.9	5.1 7.6
1800 (EPU)	BMI Penetration	542.9	523.1	-1.6

2.1.5.2.3 Description of Analyses and Evaluations

The effect of change in service conditions (temperature and water chemistry) due to the proposed EPU on the performance of the reactor coolant pressure boundary materials is discussed in the following paragraphs.

General Corrosion/Wastage of Carbon Steel Components

The proposed EPU chemistry program at PBNP suggested operating at pH levels between 7.4 and 6.9 while the lithium level is maintained between 2.35 and 2.05 ppm. The proposed chemistry limits are consistent with the recommended EPRI guidelines (PWR Primary Water Chemistry Guidelines: Vol. 1, Rev. 5, EPRI Palo Alto CA: 2003, TR-1002884, Reference 13). The industry guidelines are developed based on the experience with operating plants and are designed to prevent corrosion degradation issues with RCPB materials.

The chemistry changes resulting from the EPU do not involve introduction of any of the (stress, oxygen or halogen) contributors, therefore no impact on the material degradation is expected in the RCPB materials as a result of the EPU.

The PBNP Boric Acid Corrosion Control (BACC) program is discussed in Section B2.1.6 of the WCAP-14575-A , License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components (Reference 12). The NRC reviewed PBNP's BACC program and found PBNP's RAI responses acceptable since PBNP expanded the BACC program scope to become consistent with Generic Aging Lessons Learned (GALL) report, incorporated lessons learned from Davis-Besse, and addressed NRC's generic communications. On the basis of its review and audit findings the NRC concluded that PBNP demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation as required by 10 CFR 54.21(a)(3).

General corrosion/wastage of carbon steel is therefore not expected to be a result of the PBNP EPU.

SCC of Austenitic Stainless Steels

The two degradation mechanisms that are operative in the pressure boundary austenitic stainless steel (base and weld) materials in the RCPB are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Susceptible materials, sensitized microstructure, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC.

Westinghouse specifies that the reactor coolant chemistry be rigorously controlled, particularly with regards to oxygen, chlorides and other halogens. Through the minimization of sensitized microstructure, the potential for the occurrence of SCC due to sulfate intrusions from deminerizer resins and oxygen level prior to and during startup/shutdowns is minimized. The RCS primary water chemistry is rigorously controlled, particularly with regards to oxygen, chlorides, and other halogens, in accordance with the requirements of the PBNP chemistry control program. A review of the proposed EPU chemistry program at PBNP suggested operating at pH levels between 7.4 and 6.9 with the lithium level between 2.35 and 2.05 ppm.

There are no chemistry program changes resulting from the EPU. Therefore, chemistry does not involve introduction of any new contributor to material degradation that could be expected in the stainless steel RCPB components as a result of the EPU.

Alloy 600/82/182 Components at PBNP (Reference 3)

In pressurized water reactors the prevalent materials degradation mechanisms affecting nickel-base alloys is PWSCC. Various industry and regulatory programs require the evaluation of Alloy 600 and 82/182 filler metals and their potential for PWSCC based on their location throughout the primary system. The following components contain Alloy 600/82/182 at PBNP:

- Bottom-mounted instrument nozzles in Units 1 and 2
- Reactor Vessel Clevis Insert Lock Keys and Reactor Vessel Clevis Inserts in Units 1 and 2
- SG channelhead drains in Unit 1
- SG channelhead divider plate in Unit 1
- SG hot leg and cold leg nozzle safe end welds in Unit 2 are fabricated from Alloy 82/182 weld deposits that are inlaid with 152 material
- SG tubes in Unit 1

Alloy 690/52/152 Components at PBNP (Reference 3)

For components overly susceptible to PWSCC, when feasible, changing to Alloy 690/52/152 provides an alternative. The following components contain Alloy 690/52/152 at PBNP:

- Reactor pressure vessel head penetrations in Units 1 and 2
- SG channelhead divider plate in Unit 2
- SG channelhead vents in Unit 2

PWSCC of Nickel Base Alloy 600/82/182 and Alloy 690/52/152 Sub-Component Materials

Laboratory data and field experience suggests that Nickel base alloys are susceptible to Primary Water Stress Corrosion Cracking. The Alloy 600/82/182 PWSCC is a thermally activated process and the time "t" to initiate cracking is defined by the Arrhenius equation:

$$1/t = A\sigma^n \mathrm{Exp}\ (-Q/RT)\ \text{(Reference 4)}$$

where A is a material constant, σ is the tensile stress, Q is the activation energy of the process, and T is the service temperature. (The units of the parameters are further defined below.)

The industry Materials Reliability Program (MRP) has been tracking PWSCC in the RV head Alloy 600 components by examining the integrated time-temperature history (Reference 5). The time-temperature history has been evaluated using a term called Effective Degradation Years (EDY) based on a common reference temperature.

The EDY value is the operating time normalized to a reference temperature of 600°F. The standard Arrhenius activation energy dependence on temperature is applied to each time period with a distinct head temperature, with the thermal activation energy for crack initiation applied:

$$EDY = \sum_{j=1}^{n}\left\{\Delta EFPY_j \exp\left[-\frac{Q_i}{R}\left(\frac{1}{T_{head,j}} - \frac{1}{T_{ref}}\right)\right]\right\}$$

where:

EDY	=	total effective degradation years, normalized to a reference temperature of 600°F
$\Delta EFPY_j$	=	effective full power years accumulated during time period j
Q_i	=	activation energy for crack initiation (50 kcal/mole)
R	=	universal gas constant (1.103×10^{-3} kcal/mol-°R)
$T_{head,j}$	=	100% power head temperature during time period j (°R = °F + 459.67)
T_{ref}	=	reference temperature (600°F = 1059.67°R)

n = number of time periods with distinct 100% power head temperatures since initial head operation

As a mitigative measure, a superior PWSCC resistant Alloy 690 material is being used in the industry to replace the Alloy 600 components in service. Laboratory test data as well as service experience to date clearly demonstrated that the Alloy 690 material is resistant to PWSCC crack initiation.

Effect of EPU on the PWSCC Susceptibility of Reactor Vessel Closure Head Penetrations at PBNP Station

At PBNP the Alloy 600/82/182 Reactor Vessel Closure Head penetrations were replaced with Alloy 690/52/152 during 2005. Laboratory and field experience to date suggests that Alloy 690 and associated Alloy 52/152 welds are resistant to PWSCC. On this basis, even though an increase of 5.1°F (Table 2.1.5-1, Summary of Service Temperature Changes in the RV Closure Head and Bottom-Mounted Instrumentation (BMI) Penetrations Due to the Proposed EPU) in the closure head service temperature, and a 7.6°F increase in the hot leg temperature, are predicted due to the proposed EPU at PBNP, the proposed uprating will not significantly change the EDY nor appreciably impact the PWSCC degradation of the Alloy 690/52/152 Reactor Vessel Closure Head Penetrations. However, since only a limited amount of field data is available on the Alloy 690/52/152, to ensure safe management of the potential PWSCC issue, the NRC has recommended the following closure head inspection plan for the replacement heads.

Inspection Requirements for Replacement Heads with Alloy 690 Nozzles

Code Case N-729-1

NRC Order EA-03-009 dated February 20, 2004 (Reference 14), stipulated requirements for the interim inspection of replacement reactor pressure vessel (RPV) closure heads. Code Case N-729-1 (Reference 16) has superseded the Order.

Code Case N-729-1 (Reference 16), stipulates the following requirements for the inspection of replacement heads having Alloy 690 nozzles with Alloy 52/152 J-groove attachment welds.

- An initial bare metal visual examination shall be performed before or during the third refueling outage after installation of the replacement head, or within 5 calendar years of replacement, whichever occurs first. Repeat bare metal visual examinations shall be performed at least every third refueling outage or every 5 calendar years, whichever occurs first.
- All plants having replacement heads with Alloy 690 nozzles attached with Alloy 52/152 J groove welds shall perform an initial in-service Level 1, 2, or 3 volumetric and surface examination within 10 calendar years following head replacement.

After one cycle of operation, PBNP performed a visual inspection of the replacement reactor vessel closure head, and concluded that the new closure head maintained RCPB integrity.

PBNP will continue to monitor the Industry programs and recommendations to manage the issue for the new vessel head and take appropriate actions as necessary.

Alloy 600 Management Program at PBNP

PBNP has recently adopted a comprehensive Alloy 600 management program to address the PWSCC issue (Reference 3). The program included identification of Alloy 600/82/182 locations, evaluation and PWSCC susceptibility prioritization of the locations and development of mitigative and repair options.

The EPU therefore will not increase the susceptibility of Alloy 600/82/182 components to PWSCC at PBNP and continued participation in industry and regulatory management programs at PBNP will maintain a high level of control over PWSCC.

Thermal Aging

Thermal aging of cast stainless steel can lead to precipitation of additional phases in the ferrite and growth of existing carbides at the ferrite/austenitic boundaries that can result in loss of ductility and fracture toughness of the material. The susceptibility to thermal aging is a function of the material chemistry, aging temperature and time at temperature.

At PBNP a small increase (7.6°F) in the hot leg temperature due to the EPU was assessed. The effect of this change in the service temperature on the thermal aging is considered.

The topical report WCAP-14575-A, License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, indicates that thermal aging causes reduction in fracture toughness of the CASS component material and hence reduction in the critical flaw size that could lead to component failure. The impacted RCPB CASS components include RCS piping elbows, valve bodies, RCP pump casings and closure flanges.

An analysis of the effect of thermal embrittlement of the RCS elbows was conducted by assessing the Leak Before Break (LBB) crack stability for an extended operating period of 60 years, by taking into consideration, the loading, pipe geometry, and reduction in fracture toughness from thermal embrittlement. The evaluation documented in WCAP-14439, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the PBNP Units 1 and 2 for the Power Uprate Program, demonstrated that a significant margin exists between detected flaw size and flaw instability. In addition, a separate 'flaw tolerance' evaluation was done to manage the effect for the RCS piping components.

Westinghouse performed an evaluation of the Code Case N-481 integrity analysis to identify if it is acceptable for the extended operating period. The results of the evaluation concluded that the integrity analysis to ASME Code Case N-481 conclusions documented in WCAP-13045, Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems, and WCAP-14705, A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the PBNP Units 1 and 2, for the Units 1 and 2 RCP casings remain valid for the 60 year licensed operating period. Accordingly an aging management program to manage the thermal embrittlement effect for the RCP casings is not required beyond those examinations required for current applicable ASME Section XI Code.

The topical report WCAP-14575-A (Reference 12), proposed programs to manage the effects of thermal aging of CASS components during the period of extended operation. The NRC's assessment of these programs is contained in Section 3.3.3 of the SER. The SER Section 3.3.3

states that Valve bodies are adequately covered by existing inspection requirements in Section XI of the ASME Code and that screening for susceptibility to thermal aging is not required during the period of extended operation because the potential reduction in fracture toughness of these components should not have a significant impact on critical flaw size.

As a result of the EPU thermal aging is not expected to significantly affect cast components, including pumps, piping and valves at PBNP.

2.1.5.2.4 Evaluation of the Impact of EPU on the Renewed Plant Operating License Evaluations and License Renewal Programs

In the PBNP application for Operating License Renewal, the RCS Pressure Boundary materials of construction and likely aging effects were identified along with effective aging management programs. Following a detailed review of these aging management programs, the NRC summarized its conclusions in NUREG-1839, the Safety Evaluation Report (SER) Related to the License Renewal of PBNP Units 1 and 2, December 2005 (Reference 11).

In Section 3.1.3 of NUREG-1839, the staff concluded that the aging effects associated with the RCS components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The small increase in RCS temperature associated with the EPU does not change the set of aging effects identified in the license renewal aging evaluations nor the effectiveness of the identified license renewal aging management programs that were reviewed and found acceptable by the NRC staff.

2.1.5.2.5 Results

Based on the results of the assessment of the potential materials degradation issues resulting from the proposed Power Uprating at PBNP, it is concluded that:

- No new material degradation issues of carbon steel boric acid corrosion are expected due to the EPU water chemistry. The NRC reviewed PBNP's Boric Acid Corrosion Control program and found PBNP's program acceptable.
- The risk for PWSCC of the Reactor Vessel Closure Head Penetrations is expected to be minimal since the vessel heads were replaced during 2005, with the new heads fabricated with Alloy 690/52/152 penetrations. PBNP will continue to monitor the Industry program to manage the issue for the new vessel heads.
- The risk for PWSCC of the Alloy 600/82/182 BMI penetrations is not expected to change
- The effect of thermal aging on cast stainless steel piping and welds was addressed in the LBB analysis and the flaw tolerance evaluation for exteneded power uprate condition. The effect of the higher hot leg temperature (611.1°F) for extended power uprate condition on thermal aging including the results of the existing LBB analysis and the flaw tolerance evaluation was reviewed. Based on the review, it is concluded that the higher hot leg temperature would not have any significant impact on thermal aging as well as the results and conclusions of the LBB analysis and flaw tolerance evaluation.

- The NRC's review (PBNP License Renewal SER) concluded that PBNP's Generic Aging Lessons Learned (GALL) process identified in the License Renewal Application (LRA) is consistent with the GALL Report (NUREG-1801, Reference 15) and that PBNP has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).
- The chemistry program resulting from the EPU does not involve introduction of any of the contributors to SCC of austenitic stainless steel, therefore no material degradation is expected in the stainless steel components as a result of the EPU.

The results of the reactor coolant pressure boundary material degradation assessment showed that no new materials degradation issues will result from the proposed power uprating at PBNP. On this basis it is concluded that the new EPU environmental conditions (chemistry, temperature, and fluence) will not introduce any new aging effects on their components during 60 years of operation, nor will the EPU change the manner in which the component aging will be managed by the aging management program credited in the LRA and accepted by the NRC in the SER.

2.1.5.3 Conclusion

PBNP has reviewed the effects of the proposed EPU on the susceptibility of reactor coolant pressure boundary materials to known degradation mechanisms, and concludes that it has identified appropriate degradation management programs to address the effects of changes in the coolant chemistry, operating temperature, and fluence due to EPU on the integrity of reactor coolant pressure boundary materials. PBNP further concludes that it has demonstrated that the reactor coolant pressure boundary materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1, 9, 34 and 40. Therefore, PBNP finds the proposed EPU acceptable with respect to reactor coolant pressure boundary materials.

2.1.5.4 References

1. NP 3.2.2, Primary Water Chemistry Monitoring Program, Revision 18, March 14, 2007
2. NP 3.2.6, Strategic Primary Water Chemistry Optimization Plan, Revision 2, August 8, 2007
3. AM 3-31, Alloy 600 Management Program, Revision 0, May 15, 2008
4. Methodologies to Assess PWSCC Susceptibility of Primary Component Alloy 600 Locations in Pressurized Water Reactors, Gutti V. Rao Proceedings of the Sixth International Symposium on, Environmental Degradation of Materials in Nuclear Power Systems – Water Reactors, August 1–5, 1993, San Diego, CA
5. EPRI-MRP-117, Inspection Plan for Reactor Vessel Closure Head Penetrations in US Power Plants, July 2004
6. NRC Generic Letter (GL) 97-01, Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations, April 01, 1997

7. Information Notice (IN) 00-17, Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer, October 18, 2000

8. Bulletin 01-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles, August 03, 2001

9. Bulletin 02-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, March 18, 2002

10. Bulletin 02-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs, August 09, 2002

11. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

12. WCAP-14575-A, Aging Management Evaluation for Class I Piping and Associated Pressure Boundary Components, dated December 2000

13. EPRI-TR-1002884, Pressurized Water Reactor Primary Water Chemistry Guidelines, October 01, 2003

14. NRC Order EA-03-009, Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors, February 20, 2004

15. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, dated September 2005

16. ASME Code Case N–729–1, Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1, March 28, 2006

2.1.6 Leak-Before-Break

2.1.6.1 Regulatory Evaluation

Leak-before-break (LBB) analyses provide a means for eliminating the dynamic effects of postulated pipe ruptures for a piping system from the design basis. The NRC approval of LBB for a plant permits the licensee to: remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers); and redesign pipe-connected components, their supports, and their internals. When applicable to PBNP, the review for LBB considered:

- Direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions)
- Indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fires, flooding, missiles, and failures of structures, systems, and components in close proximity to the piping)
- Deterministic fracture mechanics and leak detection methods

The NRC's acceptance criteria for LBB are based on draft SRP, Section 3.6.3; NUREG-1061 Volume 3; and GDC 4, insofar as it allows for the exclusion of dynamic effects of postulated pipe ruptures from the design basis.

Specific review criteria are contained in the draft SRP, Section 3.6.3 (August 1987) and NUREG-1061 Volume 3 (November 1984). Other guidance is provided in Matrix 1 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4 is as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

This plant-specific General Design Criterion is very similar to 10 CFR 50 Appendix A GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures of the RCS may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probability of such ruptures is extremely low.

Unresolved Safety Issue A-2, asymmetric loss-of–coolant accident (LOCA) loads for PBNP primary loop piping licensing basis is discussed in FSAR Sections 4.1, Reactor Coolant System, Design Basis, and 15.4.3, Fracture Mechanics Analysis. The analysis for the primary loop piping is documented in WCAP-14439-P, Revision 2, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the PBNP, Units 1 and 2, for the Power Uprate and License Renewal Program, (Reference 1) and was submitted to the NRC for approval on November 5, 2003, as supplemented by letter dated April 22, 2004. On June 6, 2005, the NRC approved and issued amendments (219/224) to PBNP Operating Licenses (ML043360295).

The LBB current licensing basis for the PBNP pressurizer surge line is discussed in the FSAR, Sections 4.1, Reactor Coolant System, Design Basis, and 15.4.3, Fracture Mechanics Analysis. The analysis for the pressurizer surge line is documented in WCAP-15065-P-A Revision 1, Technical Justification for Eliminating Pressurizer Surge and Rupture as the Structural Design Basis for the PBNP Units 1 and 2, (Reference 2) and was submitted to the NRC on December 2, 1999, as supplemented on July 7 and August 16, 2000. On December 15, 2000, the NRC concluded that LBB behavior has been demonstrated for the pressurizer surge line piping and that PBNP may remove consideration of the dynamic effects associated with the postulated rupture of the pressurizer surge line piping from the licensing basis of PBNP, (ML003777863).

The LBB current licensing basis for the PBNP accumulator lines is discussed in the FSAR, Sections 6.1.1, Engineered Safety Features Criteria, and 15.4.3, Fracture Mechanics Analysis. The LBB analysis for the accumulator lines is documented in WCAP-15107-P-A, Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for Point Beach Units 1 and 2 Nuclear Plants, (Reference 3) and was submitted to the NRC on December 2, 1999, as supplemented on July 7 and August 16, 2000. On November 7, 2000, the NRC concluded that PBNP may remove consideration of the dynamic effects associated with the postulated rupture of the analyzed portions of the accumulator line piping from the licensing basis of PBNP, (ML003767681).

The LBB current licensing basis for the PBNP Residual Heat Removal (RHR) lines is discussed in FSAR Sections 9.0, Auxiliary and Emergency Systems and 15.4.3, Fracture Mechanics Analysis. The LBB analysis for the RHR lines is documented in WCAP-15105-P-A, Technical Justification for Eliminating Residual Heat Removal (RHR) Lines Rupture as the Structural Design Basis for PBNP Units 1 and 2 Nuclear Plants, (Reference 4) and was submitted December 2, 1999, as supplemented July 7 and August 16, 2000. On December 18, 2000, the NRC concluded that PBNP may remove consideration of the dynamic effects associated with the postulated rupture of the analyzed portions of the RHR system piping from the licensing basis of PBNP, (ML003777964).

In addition to the evaluations described in the FSAR sections listed above, the PBNP LBB analyses were evaluated for plant license renewal. Fracture Mechanics Analyses for license renewal are documented in Section 4.4 of:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 8)

The aging evaluations are documented in Sections 4.4.4, 4.4.5, 4.4.6 and 4.4.7 of NUREG 1839.

2.1.6.2 Technical Evaluation

2.1.6.2.1 Introduction

The original structural design basis of the RCS for the PBNP, required consideration of dynamic effects resulting from postulated pipe breaks and the need to incorporate protective measures for such breaks into the design. Subsequent to the original PBNP design, an additional concern regarding asymmetric blowdown loads was raised as described in Unresolved Safety Issue A-2, Asymmetric Blowdown Loads on the Reactor Coolant System, and Generic Letter 84-04, - Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, (Reference 5). Generic Letter 84-04 provided the NRC safety evaluation for the analyses submitted by Westinghouse for a group of plants that included the PBNP to resolve Unresolved Safety Issue A-2, asymmetric LOCA loads. Research by the NRC and industry, coupled with operating experience, determined that safety could be negatively impacted by placement of pipe whip restraints on certain systems. As a result, NRC and industry initiatives resulted in demonstrating that LBB criteria can be applied to RCS piping based on fracture mechanics technology. By letter (Reference 6) dated May 6, 1986, the NRC acknowledged that PBNP was bounded by the generic Westinghouse LBB analysis and met the additional criteria identified in NRC Generic Letter 84-04 and therefore the asymmetric blowdown loads resulting from double-ended pipe breaks in primary loop piping need not be considered as a design basis for the PBNP.

A plant-specific LBB analysis for the PBNP Units 1 and 2 primary loop piping was subsequently performed in 1996, and subsequently revised in 2002 and 2003. The results of the current PBNP LBB analysis for primary loop piping are documented in WCAP-14439-P, Revision 2 (Reference 1). Plant-specific LBB analyses for the pressurizer surge line, accumulator lines and RHR lines are documented in WCAP-15065-P-A, Revision 1 (Reference 2), WCAP-15107-P-A, Revision 1 (Reference 3) and WCAP-15105-P-A, Revision 1 (Reference 4), respectively. The LBB analyses were further evaluated to determine the impacts of uprated (1.7% calorimetric mini uprate) power conditions in 2002. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analyses and the conclusions of the original LBB remained unchanged and also valid for the 60 year operating (license renewal) period. The current structural design basis of the PBNP includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the reactor coolant system (RCS) primary loop piping, pressurizer surge line, accumulator lines and the RHR lines. The purpose of this LR section is to describe the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis continues to be valid following implementation of the EPU, and that lines (primary loop piping, pressurizer surge line, accumulator and the RHR lines) for which PBNP credits LBB continue to comply with the requirements of GDC-4, the draft SRP Section 3.6.3 and NUREG-1061, Volume 3.

To demonstrate the elimination of primary loop piping, pressurizer surge line, RHR and the accumulator lines pipe breaks, the following objectives had to be achieved:

- Demonstrate that margin exists between the “critical” flaw size and a postulated flaw that yields a detectable leak rate

- Demonstrate that there is sufficient margin between the leakage through a postulated flaw and the leak detection capability
- Demonstrate margin on the applied load
- Demonstrate that fatigue crack growth is negligible

These objectives were met in the current LBB analyses

To support the EPU at the PBNP, the current LBB analyses were evaluated to address the proposed EPU conditions.

2.1.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The loadings, operating pressure, and temperature parameters for the EPU were used in the evaluation.

The parameters that are important in the evaluation are the piping forces, moments, normal operating temperature, and normal operating pressure. These parameters were used as input in the evaluation. The normal EPU operating temperature range and normal operating pressure conditions are provided in LR Section 1.1, Nuclear Steam Supply System Parameters.

Acceptance Criteria

The LBB acceptance criteria are based on the Draft SRP, Section 3.6.3 and NUREG-1061 Volume 3. The LBB recommended margins are as follows:

- Margin of 10.0 on leak rate
- Margin of 2.0 on flaw size
- Margin on loads of 1.0 (if using faulted load combinations by absolute summation method).

2.1.6.2.3 Description of Analyses and Evaluations

Primary Loop Piping

Westinghouse performed a plant-specific LBB analysis for the PBNP Units 1 and 2 primary loop piping in 2003 for the PBNP License Renewal Program. The results of the analysis were documented in WCAP-14439-P, Revision 2 (Reference 1).

The recommendations and criteria proposed in NUREG-1061, Volume 3, and the draft SRP, Section 3.6.3 are incorporated in the EPU LBB evaluation. The primary loop piping dead weight, normal thermal expansion, and safe shutdown earthquake (SSE) and pressure loads due to the EPU conditions were employed. The EPU normal operating temperature range and pressure were used in the evaluation. The evaluation results demonstrated that all the LBB acceptance criteria (margin of 10.0 on leak rate, maring of 2.0 on flaw size, and margin on loads of 1.0 using faulted load combinations by absolute summation method) for the primary loop piping continue to be satisfied for the EPU conditions.

Pressurizer Surge Line Piping

The PBNP pressurizer surge line analysis for the application of LBB considering the effects of the thermal stratification is documented in WCAP-15065-P-A, Revision 1 (Reference 2). Based on the evaluations documented in LR Section 2.2.2.1, NSSS Piping, Components and Supports, the current design basis pressurizer surge line loads and results including the effects of thermal stratification remain applicable for the EPU. Therefore, the PBNP pressurizer surge line evaluation results determined that the conclusions of the current LBB analysis shown in WCAP-15065-P-A, Revision 1 remain valid for the EPU conditions.

Accumulator Lines

The PBNP Accumulator lines analysis for the application of LBB is documented in WCAP-15107-P-A, Revision 1 (Reference 3). Based on the evaluations documented in LR Section 2.2.2.1, NSSS Piping, Components and Supports, the current design basis Accumulator lines loads and results remain applicable for the EPU. Therefore, the PBNP Accumulator lines evaluation results determined that the conclusions of the current LBB analysis shown in WCAP-15107-P-A, Revision 1 (Reference 3), remain valid for the EPU conditions.

RHR Lines

The PBNP RHR lines analysis for the application of LBB is documented in WCAP-15105-P-A, Revision 1 (Reference 4). Based on the evaluations documented in LR Section 2.2.2.1, NSSS Piping, Components and Supports, of this report, the current design basis RHR lines loads and results remain applicable for the EPU. Therefore, the PBNP RHR lines evaluation results determined that the conclusions of the current LBB analysis shown in WCAP-15105-P-A, Revision 1(Reference 4), remain valid for the EPU conditions.

Limitations on the Application of LBB

The LBB approach should not be considered applicable to high energy fluid system piping, or portions thereof, that operating experience has indicated particular susceptibility to failure from the effects of corrosion (e.g., intergranular stress corrosion cracking), water hammer or low and high cycle (i.e., thermal, mechanical) fatigue. For the PBNP LBB applications, these limitations are addressed in the WCAP-14439-P, Revision 2 (Reference 1, for primary loop piping), WCAP-15065-P-A, Revision 1 (Reference 2, for the pressurizer surge line), WCAP-15107-P-A, Revision 1 (Reference 3, for the accumulator lines) and WCAP-15105-P-A, Revision 1 (Reference 4, for the RHR lines).

2.1.6.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the primary loop piping LBB has been evaluated. The 40-year design transients and cycles (NUREG-1839) remain valid for the 60-year life of the plant and therefore the fatigue crack growth (FCG) analyses documented in Reference 1 through Reference 4 remain valid for the EPU conditions. The current analyses used the end of life fracture toughness values due to the thermal aging effect on the cast stainless steel material and therefore fracture toughness values used in the current analyses are also valid for the EPU conditions. The aging evaluations documented in Reference 1 through Reference 4 and approved by the NRC in the License Renewal Safety Evaluation Report (SER) Sections 4.4.4, 4.4.5, 4.4.6 and 4.4.7 for PBNP Units 1 and 2 (NUREG 1839) remain valid for the EPU conditions.

PBNP has thus evaluated the impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the primary loop piping, surge line piping, accumulator line piping and RHR piping LBB analyses. The aging evaluations approved by the NRC in NUREG 1839 remain valid for EPU conditions.

2.1.6.2.5 Results

The evaluation results demonstrated the following:

Leak Rate – A margin of 10.0 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gpm.

Flaw Size – A margin of 2.0 or more exists between the critical flaw size and the leakage flaw size.

Loads – A margin of 1.0 (using faulted load combinations by absolute summation method) exists.

The evaluation results demonstrated that the LBB conclusions provided in current LBB analyses for the PBNP remain unchanged for the EPU conditions. PBNP Units 1 and 2 RCS pressure boundary leak detection capability is 1 gpm within 4 hours.

It is therefore concluded that the LBB acceptance criteria continue to be satisfied for the PBNP Units 1 and 2 primary loop piping, pressurizer surge line, accumulator lines and the RHR lines at the EPU conditions. All the recommended margins continue to be satisfied and the conclusions shown in the current LBB analyses remain valid. It was therefore concluded that the dynamic effects of primary loop piping, pressurizer surge line, accumulator lines and the RHR lines pipe breaks need not be considered in the structural design basis of the PBNP at the EPU conditions.

2.1.6.3 Conclusions

PBNP has reviewed the evaluation of the effects of the EPU conditions on the LBB analyses for the PBNP and determined that the changes in the primary system pressure and temperature range and the associated effects on the LBB analyses have been adequately addressed. PBNP further determined that the evaluations demonstrated that the LBB analyses will continue to remain valid following implementation of the EPU and that lines that credit LBB will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 40. Therefore, PBNP finds the EPU acceptable with respect to all aspects of LBB for the PBNP.

2.1.6.4 References

1. WCAP-14439-P, Revision 2, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 for the Power Uprate and License Renewal Program, September 2003 (ML043360295)

2. WCAP-15065-P-A, Revision 1, Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 Nuclear Plants, June 2001

3. WCAP-15107-P-A, Revision 1, Technical Justification for Eliminating Accumulator Lines Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 Nuclear Plants, June 2001

4. WCAP-15105-P-A, Revision 1, Technical Justification for Eliminating Residual Heat Removal (RHR) Lines Rupture as the Structural Design Basis for the Point Beach Nuclear Plant Units 1 and 2 Nuclear Plants, June 2001

5. Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe breaks in PWR Primary Main Loops, Generic Letter 84-04, February 1, 1984

6. NRC Letter to WE, Docket Nos. 50-266 and 50-301, Exemption from the Requirements of 10 CFR 50 Appendix A, General Design Criteria 4,dated May 6, 1986

7. WCAP-13045, Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems, September 1991

8. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.1.7 Protective Coating Systems (Paints) - Organic Materials

2.1.7.1 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. PBNP's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects.

The NRC's acceptance criteria for protective coating systems are based on:

- 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs
- Regulatory Guide 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

PBNP Current Licensing Basis

PBNP is committed in part to follow of Regulatory Guide 1.54 (1973), Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, which endorses and supplements ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Power Plants, for activities that affect quality and occur during the operational phase, and that are comparable in nature and extent to related activities occurring during construction.

Procedures and programmatic controls ensure that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented. The surface preparation, application and surveillance during installation of Service Level I coatings used for new applications or repair/replacement activities inside containment meet the applicable portions of RG 1.54 and ANSI N101.4-1972.

Relatively small amount of coatings applied by vendors on supplied equipment, miscellaneous structural supports, and small areas of touch-up on qualified Service Level I coatings may not be Service Level I coatings. With the exception of isolated minor touch-up repairs (i.e., less than 1 ft^2), all coating repairs, maintenance, and applications inside containment are required to be performed with Service Level I coatings.

The protective coating systems are discussed in FSAR Sections 1.4, Quality Assurance Program, 5.1.2.1, Containment System Structure Design, General Description, 5.6.2.4, Construction - Compatibility of Protective Coatings with Post Accident Environment Compatibility, 5.6.2.5, Construction - Evaluation of the Compatibility of Concrete - ECC Solution in the Post Accident Environment and 6.4.3, Containment Spray System Evaluation, and 14.3.4, Containment Integrity Evaluation.

PBNP provided a response to Generic Letter 98-04 (Reference 2), to ensure the Service Level I coatings inside the containment do not detach from their substrate during a design basis LOCA. The PBNP response to GL 98-04 (Reference 2) has been accepted by the NRC.

Procedures and programmatic controls ensure that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented. The surface preparation, application and surveillance during installation of Service Level I coatings used for new applications or repair/replacement activities inside containment meet the applicable portions of RG 1.54 and ANSI N101.4-1972. PBNP was built and licensed prior to RG 1.54 being issued, and, as such, does not conform fully to all aspects of ANSI N101.4-1972 and RG 1.54. The original coatings inside containment were applied without the documentation and/or testing necessary to be considered Service Level I coatings. These original coatings are considered acceptable based on WCAP-7198-L and the evaluation in FSAR Section 5.6.2.4.

The PBNP program provides adequate assurance that the applicable requirements for the procurement, application, inspection, and maintenance of Service Level I coatings in containment are implemented, and that maintains a detailed inventory of degraded and non-conforming coatings to ensure the coatings are maintained within the evaluated limits of design basis analyses for the ECCS. Refueling frequency coatings inspections will ensure the total inventory of coatings will remain bounded by the analyses.

Although the benefits derived from protective coatings are recognized, coatings, in and of themselves, do not perform License Renewal intended functions. Therefore, protective coatings are not credited with program managing the effects of aging.

2.1.7.2 Technical Evaluation

Introduction

The coating system's function is to provide corrosion and erosion control and to facilitate decontamination in the event of radioactive material leakage into the containment. Failure of coating systems inside the containment before and/or during a design bases accident that requires the recirculation of water from the containment sump could degrade or fail the accident response systems' functions by clogging the sump screens. NRC Generic Letter 98-04 (Reference 2), required plant operators to address the qualification of the coating systems inside containment. The PBNP response stated that, For PBNP Unit 1 & 2, Service Level 1 coatings are subject to the requirements defined in the FSAR, which commits to Regulatory Guide 1.54 (1973), Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants (Reference 3), and ANSI Standard N101.4 (1972), Quality Assurance for Protective Coatings Applied to Nuclear Facilities.

Resolution of GL 2004-02 (Reference 4), Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized Water Reactors, which discusses the clogging of containment emergency sumps, is managed under an existing PBNP program. The resolution of this is ongoing between PBNP and the NRC and is not addressed as a power uprate issue in this report. With regard to Protective Coating System failures, as relates to GL 2004-02 (Reference 4) , the design basis conditions (temperature, pressure, radiation dose and pH) for protective coatings inside containment bound the conditions to which the coatings will be subject to at EPU and the resolution of GL 2004-02 (Reference 4), will not be impacted. Refer to Description of Analysis and Evaluation below for specific details regarding this evaluation.

The Protective Coating Program assesses the condition of all coatings inside the containment. The program ensures appropriate corrective actions are taken to maintain the design basis requirement and identify degraded coatings during monitoring inspections. Corrective actions are performed in accordance with 10 CFR 50 Appendix B procedures. The procurement, application and maintenance requirements of 10 CFR 50 Appendix B are implemented through specification of appropriate technical and quality requirements for the Service Level 1 Coatings Program.

Description of Analyses and Evaluations

The coatings were evaluated by comparing the EPU parameters with the qualification acceptance parameters under which the coating systems were previously accepted by the NRC.

The containment post-LOCA accident temperature profile for EPU indicates a peak temperature of 280°F and then decreasing temperature which drops below 150°F approximately 28 hours after the accident (see Section 2.6.1, Primary Containment Functional Design). As indicated in FSAR Section 5.6.2.4, Construction, Compatibility of Protective Coatings With Post Accident Environment, testing of inorganic zincs, modified phenolics and epoxy coatings has been performed. The tests indicated that the coatings were resistant (no significant loss of adhesion to the substrate, nor any formation of deterioration products) to an environment high temperature (320°F maximum) and alkaline sodium borate. Long-term tests included exposure to a spray solution at 150°F to 175°F for 60 days after being subjected to a design basis accident cycle.

EPU containment pressure following the LOCA remains bounded by the design basis containment pressure of the protective coating systems.

The total integrated radiation dose after the implementation of EPU is bounded by the coating system qualification dose levels. The total integrated dose for the EPU includes the 60 year operating time dose, accident dose, and the post accident dose over 1 year. This integrated dose value is calculated to be 2.71E8 Rads (see LR Section 2.3.1, Environmental Qualification of Electrical Equipment). The total integrated dose value is still bounded by the accepted total integrated dose, which has been tested to and accepted at 1.0E9 Rads. In order to control protective coatings within the containment, a program is in place at PBNP with plant specific procedures which control procurement and testing of coatings in accordance with 10 CFR 50, Appendix B requirements. Procedures are established to control surface preparation, application, surveillance and maintenance activities for all protective coatings. Any unqualified coatings and degraded qualified coatings within the containment are quantified and monitored at each outage to evaluate coatings in accordance with established acceptance criteria to ensure that any particulate debris remains bounded. Repair and/or replacement of existing coatings will use a level 1 coating in accordance with Regulatory Guide 1.54 (Reference 3), requirements.

The Reactor Coolant Water Chemistry Specification (FSAR Table 4.2-2) indicates a pH range of 4.2 to 10.5 depending on the concentration of boric acid and alkali present. There will be no change in this range under EPU conditions. As a result of the pH remaining unchanged at EPU the post-accident pH of containment spray at EPU conditions would be expected to remain the same as it would be under current operating conditions. Therefore the EPU has no impact on the coatings within the containment from exposure to chemical spray.

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

In regard to the aging programs and aging influences described in the License Renewal SER NUREG 1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2 (Reference 5), the Protective Coating Program was evaluated and it was concluded that this system was not in scope of icense Renewal.

Results

The containment temperature, pressure and chemical spray conditions associated with EPU normal operation, design basis accident conditions and post accident operations are within the coating qualification conditions.

After implementation of EPU, areas inside the containment would receive a total integrated dose of not greater than 2.71E8 Rads, including an accident dose and 1 year post-accident dose. Coatings are tested to radiation doses of up to 1.0E9 Rads. For unqualified coatings, PBNP has a program to monitor and remove/ repair coatings within the containment which do not meet established acceptance criteria. Therefore, based on comparable dose ratings there is reasonable assurance the EPU radiation dose will not cause degradation of the coatings inside the containment and operation of the safety related systems will not be affected.

License renewal did not result in changes to the Protective Coatings Monitoring and Maintenance Program because it is an ongoing maintenance activity rather than an aging management program.

2.1.7.3 Conclusions

PBNP has evaluated the effects of the proposed EPU on protective coating systems and concludes that PBNP has appropriately addressed the impact of changes in conditions following a LOCA and their effects on the protective coatings. PBNP further concludes that PBNP 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 10 CFR 50, Appendix B and Regulatory Guide 1.54 (1973, Reference 3). Therefore, PBNP finds the proposed EPU acceptable with respect to protective coatings systems.

2.1.7.4 References

1. NRC Letter to Michael B. Sellman regarding Point Beach Nuclear Plant, Units 1 and 2 - Completion of Licensing Action for Generic Letter 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident because of Construction and Protective Coating Deficiencies and Foreign Material in Containment, dated January 14, 2000 (TAC NOS. MA4086 and MA4087).

2. NRC Generic Letter (GL) 98-04 Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment, July 14, 1998

3. Reguloatry Guide 1.54, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants, June 1973

4. NRC Generic Letter (GL) 2004-02, Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors, September 13, 2004

5. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.1.8 Flow-Accelerated Corrosion

2.1.8.1 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 immune to flow-accelerated corrosion, and flow-accelerated corrosion is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to flow-accelerated corrosion 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 flow-accelerated corrosion effects, in most cases, cannot be achieved. Loss of material by flow-accelerated corrosion will, therefore, occur. PBNP has reviewed the effects of the proposed EPU on flow-accelerated corrosion and the adequacy of the flow-accelerated corrosion program to predict the rate of loss so repair or replacement of damaged components will be made before they reach critical thickness.

The PBNP flow-accelerated corrosion program is based on NUREG-1344 (Reference 6), GL 89-08 (Reference 2), and the guidelines in Electric Power Research Institute (EPRI) Report NSAC-202L-R3 (Reference 1). It consists of predicting loss of material using the CHECWORKS computer code.

The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

PBNP Current Licensing Basis

The PBNP Flow Accelerated Corrosion Program manages aging effects due to flow-accelerated corrosion on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies, which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R3 (Reference 1) for an effective FAC program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

The PBNP FAC program is responsive to Generic Letter 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning (Reference 2), and implements the guidelines in EPRI Report, NSAC-202L-R3, Recommendations for an Effective Flow-Accelerated Corrosion Program (Reference 1). Other source/development documents include NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants (Reference 3) and NRC Information Notice 93-21, Summary of NRC Observations Compiled during Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs (Reference 4).

The PBNP FAC program is described in FSAR Chapter 15 Section 15.2.11, Flow-Accelerated Corrosion Program.

In addition to the evaluations described in the FSAR, the Flow-Accelerated Corrosion Program was evaluated for the PBNP License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 7)

The Flow-Accelerated Corrosion Program is addressed in License Renewal Safety Evaluation Report Section 3.0.3.2.11.

2.1.8.2 Technical Evaluation

Introduction

This section addresses the following Flow Accelerated Corrosion Program topics:

- Program scope and attributes
- Piping/component inspection
- Evaluation of inspection data
- Component repair/replacement

Flow Accelerated Corrosion Program Scope/Attributes

The Flow Accelerated Corrosion program is designed to detect wall thinning caused by flow-accelerated corrosion before a leak or catastrophic failure occurs. Susceptible areas of systems are identified and inspected with ultrasonic, visual and radiographic techniques. The program has been in place since September 1987, and was initiated in response to NRC BL 87-01 (Reference 3) and later NRC GL 89-08 (Reference 2).

The activities associated with ensuring that flow-accelerated corrosion does not result in unacceptable degradation of the structural integrity of carbon steel piping systems are included in the FAC program . The elements/activities associated with the FAC program are identified and addressed in this section.

In addition to the requirements of NSAC-202L (Reference 1) , EPRI recommendations for small bore piping are considered for the PBNP FAC Program. All piping and equipment for the systems identified below are considered susceptible to flow accelerated corrosion unless they are within one of the following exclusion categories:

Non-water systems

Pipe material with FAC resistance alloy elements

Single-phase water lines with operating temperature <200°F

Steam Quality: steam systems with quality >99.5%

Piping systems with no flow or that operate less than 2% of plant operating time

Piping with high oxygen content (service water)

The following systems are considered susceptible to flow accelerated corrosion and are included in the FAC program:

- Main Steam (MS)

- Moisture Separator/Reheater Drains (MS)
- Extraction Steam (MS)
- Feedwater (FW)
- Condensate (CS)
- Heater Drains (FD)
- Heater Vents (FD)
- Steam Generator Blowdown (MS)
- Turbine Gland Steam (MS)

The Flow Accelerated Corrosion Program is an existing program that is consistent with, but includes exception to, NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Section XI.M17, Flow Accelerated Corrosion (Reference 8). These exceptions are current commitments made as a result of License Renewal Requirements and contain specific requirements to expand scope on components inspected that are below a specific minimum.

The objectives of this program are to control and monitor FAC, plan inspections, prevent failures, and implement a long-term strategy to reduce loss of material due to FAC. To aid in the planning of inspections and choosing inspection locations, PBNP uses the FAC module of CHECWORKS (Reference 5), an EPRI computer program developed solely for the management of FAC.

Piping/Component Inspection

Examination point selection is based on the following:

CHECWORKS Model – piping components that are evaluated to have a high wear rate or a predicted low time remaining to reach minimum allowable wall thickness

Plant History – piping components that have experienced flow accelerated corrosion degradation

Industry Experience – piping components which are similar to those which have experienced flow accelerated corrosion at other plants.

Piping components which have been identified as having flow accelerated corrosion degradation during PBNP maintenance activities.

These items are described in the following subsections:

<u>CHECWORKS</u>

The CHECWORKS computer code, developed by EPRI, is used to evaluate piping systems susceptible to flow-accelerated corrosion mechanisms. Susceptible large bore lines are modeled. Although not all small bore susceptible lines are modeled, they are inspected and tracked under other programs using criteria and guidelines similar to those in the FAC program. Parameters including operating conditions, routing geometry, and piping properties, are inputted for CHECWORKS program evaluations.

The primary objective of the CHECWORKS Program evaluation is to ensure that the inspections are focused on the areas most likely to be experiencing flow accelerated corrosion degradation such that the likelihood of catastrophic failures is minimized. The CHECWORKS evaluations identify recommended initial locations that should be inspected to determine the condition of the piping system. Data derived from the inspection of the recommended initial locations is used to develop a plant specific corrosion model of susceptible piping.

The most susceptible components from each aforementioned system (FD, CS, FW, and MS) are evaluated to determine if inspection is needed. Using the plant-specific model, CHECWORKS refines the ranking locations and provides quantified estimates of corrosion rates and times until minimum code allowable wall thickness will be reached. The CHECWORKS models are updated based on periodic NDE inspections.

The inspection scope, to the extent practical, uses input from guidelines stated in NSAC-202L (Reference 1)and Program documents. This scope, to the extent practical, includes components from each geometry type be examined so the most representative sample of items with highest probability of damage are examined.

Tables 2.1.8-2, Comparison of Predicted and Measured Wall Thickness (Unit 1), and Tables 2.1.8-4, Comparison of Predicted and Measured Wall Thickness (Unit 2), provide a comparison of wall thickness predicted by CHECWORKS with the measured wall thickness for several representative components from the various systems that are included in the FAC program.

Industry Experience

Components that have displayed susceptibility for corrosion in other power plants are given consideration in the inspection point selection process. These industry experience points are typically downstream of components, which cause flow restriction or otherwise add turbulence (e.g., downstream of control valves and orifices). A review of the inspection results is performed to assure plant-specific experience has been included in the selection of components for examination.

The PBNP FAC coordinator is notified of industry events primarily through the CHECWORKS Users Group (CHUG) or site OE program. INPO SOERs. Inspections related to Industry events are entered into the next outage's work plan as soon if the event is considered applicable to PBNP.

PBNP History

PBNP maintains record of piping components that have experienced flow accelerated corrosion degradation, which required past repair or replacement. These locations are considered in the FAC Program. Continuing inspection at these points depends on the replacement material used.

There are specific components contained in the program based on susceptibility to FAC degradation. PBNP experienced a shell failure of a Feedwater heat exchanger in 1999. Based upon this failure, the feedwater heat exchangers are included in the PBNP FAC program. The PBNP FAC program monitors and tracks the shell thickness of accessible and susceptible Feedwater heater shells in accordance with NSAC-202L-R3, Appendix B (Reference 1). CHECWORKS is used to track the UT thickness measurements from these inspections. Since the CHECWORKS program is specific to piping systems, the heat exchangers are not modeled via CHECKWORKS. As part of EPU, all of the Feedwater Heaters will have a shell material which is resistant to FAC. These heat exchangers will continue to be monitored within the FAC program until FAC resistance can be verified during future outages. Other components are added when susceptibility to FAC degradation is identified.

Inspection Techniques

Components can be inspected for FAC wear using visual, ultrasonic, eddy current, and radiography techniques.

Ultrasonic inspection is the preferred method of inspection for FAC damage to large bore piping components because it provides more complete data for measuring the remaining wall thickness. A scanning method of inspection on most small bore piping is recommended, however, ultrasonic inspection with grid for small bore piping may not be practical.

Radiography inspection is commonly used as an inspection tool for FAC damage on small bore piping components.

Evaluation of Inspection Data

A wear calculation is performed for each component examined. For those components where prior examination data does not exist, there are three methods available in CHECWORKS, namely, Band, Area and Moving Blanket for determining wear rates. For those components where baseline or prior examination data is available, a Point-to-Point method or the Band, Area and Moving Blanket methods may be used for wear rate determination. Based on the wear rate the number of operating cycles remaining before the component reaches code minimum allowable wall thickness is determined. Component reinspections are established for no later than the refueling outage prior to the point at which the minimum wall thickness would be reached.

Component Repair/Replacement

The process/criteria for determining the need for repair or replacement of a component involves:

- Determining the minimum wall thickness, t_{min}, based on the hoop stress due to internal design pressure and/or the longitudinal stress due to internal design pressure plus bending moment due to dead weight.
- Measuring the current wall thickness
- Determining the wear rate

If the measured wall thickness is greater than 87.5% of the nominal wall thickness, the component is acceptable for continued service.

If examinations of components discover degradation which meets the criteria of the licensing renewal commitments (exception to the GALL Report Section XI.M.17), then additional components will be inspected to bound the thinning which meet the guidelines of NSAC-202L (Reference 1) and commitments.

Inspection results are used to calculate the number of operating cycles remaining before the component reaches code minimum allowable wall thickness. If evaluations indicate that an area will reach code minimum allowable wall thickness before the next inspection interval, the component must be replaced, repaired, or reevaluated. If the measured wall thickness is less than the code minimum allowable wall thickness, a local thinning evaluation is performed. If the local thinning evaluation results are unsatisfactory for a particular component, it must be replaced or repaired.

If the engineering analysis determines that a component requires repair or replacement before the next inspection interval, then the component is scheduled for repair or replacement.

The existing criteria for repair/replacement of piping are consistent with the guidelines in EPRI Report, NSAC-202L-R3 (Reference 1) and also described in Application for Renewed Operating License, Appendix B2.1.11.

Description of Analyses and Evaluations

Main Steam

As addressed in LR Section 2.5.5.1, Main Steam, Table 2.5.5.1-1, the EPU will result in small changes (decrease) in operating pressures and temperatures, and an approximately 27% increase in velocities in the main steam lines from the steam generators to the high pressure turbine stop valves. The highest calculated velocity at EPU conditions is well below the industry guidelines. The steam quality within these lines prior to EPU is 99.75%, which is not susceptible to Flow Accelerated Corrosion in accordance with NSAC-202L-R3 (Reference 1). After EPU, moisture carryover increases to 0.25% and the quality of the steam remains above the 99.5%. The main steam lines between the steam generators and containment penetrations are included in the FAC program as a monitoring tool due to the high safety risk involved with these lines. Since the highest calculated velocity is well below the industry guidelines and steam quality maintains this portion of the main steam lines not-susceptible to FAC in accordance with NSAC-202L (Reference 1); the existing model for FAC within CHECWORKS for this portion of the Main Steam System is not impacted. Monitoring for these steam lines per FAC program will continue after EPU implementation.

Moisture Separator/Reheater Drains

As addressed in LR Section 2.5.5.1, Main Steam, EPU will result in changes in operating pressures and temperatures in the main steam lines to the moisture separator reheaters, the cold reheat steam lines from the high pressure turbine to the moisture separator reheaters (cold reheat/crossunder piping), and the hot reheat steam lines from the moisture separator reheaters to the low pressure turbines (hot reheat/crossover piping). Although there are pressure and temperature changes, the calculated fluid velocities within these lines at EPU conditions remain essentially unchanged from the velocities at current conditions.

The crossover piping is carbon steel. The steam velocity in this piping is essentially unchanged at EPU conditions and is well within industry guidelines (refer to LR Section 2.5.5.1, Main Steam). The crossover piping system is not currently included in the FAC program due to its low steam velocity and is not required to be included in the FAC program after EPU implementation.

The crossunder piping system is a combination of stainess steel and carbon steel piping segments. Its velocity is also essentially unchanged at EPU conditions, but is above industry guidelines (refer to LR Section 2.5.5.1, Main Steam). The cross-under piping is being monitored by PBNP using criteria and guidelines similar to those included in the FAC program. No changes to the monitoring program inspection criteria or acceptance criteria are required due to EPU.

Extraction Steam System

Extraction Steam system lines from the highpressure turbine to the feedwater heaters are stainless steel. They are not susceptible to flow accelerated corrosion and, therefore, are not part of the current FAC program.

For the EPU condition, the calculated flow velocities for the extraction steam piping to feedwater heaters 5A/B and 4A/B are below industry recommended maximum velocities.

For the extraction steam piping from the low-pressure turbine to feedwater heaters 3A/B, 2A/B and 1A/B the flow velocities through the lines for EPU conditions are also below the industry recommended maximum velocities. For piping associated with FWH 3A/B, the steam is superheated steam; therefore, the extraction steam piping is not required to be included in the FAC program. Saturated Steam temperature in piping associated with FWH 1A/B and 2 A/B is approximately 200°F, therefore, they are not included in FAC monitoring program.

The calculated velocities through the nozzles for EPU conditions are below the Heat Exchanger Institute (HEI) Standards recommended velocities except for heaters 3 A/B, which are higher than the HEI recommended velocity. Although the feedwater heaters 3 A/B extraction steam nozzles are SA 106 Gr B, the steam quality for these nozzles is dry steam (Quality = 1.0). The remaining feedwater heaters extraction steam nozzles are also carbon steel (SA 106 Gr B or SA 105). However, as mentioned above, velocity through these nozzles are below the HEI recommended velocities. Therefore, these nozzles are not included in the FAC program.

Condensate and Feedwater system

The Condensate and Feedwater system was evaluated for EPU conditions. The system piping design pressures are acceptable as the maximum and normal pressures during EPU operation are below their design pressure with sufficient margin. The maximum temperatures during EPU operation are below the piping design temperatures with sufficient margin. The Condensate and Feedwater system piping design temperatures are acceptable for EPU. The Condensate and Feedwater system piping velocity evaluation at EPU conditions indicated that velocities through seventeen piping sections were higher at EPU conditions. Eight of these seventeen lines are single-phase lines with temperatures less than 100°F. Therefore, these lines are not required to be included in FAC program. The remaining nine lines are already part of the current FAC program. Monitoring of these lines per FAC program will continue after EPU implementation.

Heater Drains and Vents

Heater Drains and Vents system operating parameters for EPU conditions were evaluated. The velocity for normal drains, from feedwater heaters 5A/B to feedwater heaters 4A/B increased. The velocity through this piping is higher than the industry standard. This piping is part of the FAC program, and monitoring of this piping per the requirements of FAC program will continue after EPU implementation.

Emergency drain lines flows for the heater drains and vents system increased for the EPU operating condition; however, these lines are not in service during normal operation. Per

NSAC-202L-R3 (Reference 1), systems with no flow or those that operate less than 2% of plant operating time are excluded from further evaluation. Even though the emergency drain lines operate intermittently, they carry two phase flow when operating. Therefore, at PBNP these lines are part of the FAC program and will be inspected as necessary.

Steam Generator Blowdown

As indicated in the Flow Accelerated Corrosion Program Scope/Attributes section above, the steam generator blowdown system is included in the FAC Program. As addressed in LR Section 2.1.10, Steam Generator Blowdown System, at EPU conditions the operating temperatures and pressures in the steam generators decrease slightly. The operating pressure and temperature in the steam generator blowdown tank and interconnecting piping and valves are not significantly changed. However, the existing design pressure and temperature of the steam generators, 1085 psig/555°F, remain bounding for EPU conditions. These values are based on the no-load operating condition, which does not change at EPU. LR Section 2.1.10, Steam Generator Blowdown System, also indicates that the blowdown required to control secondary chemistry and steam generator solids will not be impacted by power uprate.

Since the blowdown flow is not changed for the EPU, the velocities in the blowdown lines are not affected by the EPU. There is only a small change in steam generator blowdown temperature and pressure at EPU conditions. Accordingly, no appreciable increased potential for flow accelerated corrosion exists with the steam generator blowdown system at EPU conditions. Monitoring of the steam generator blowdown system per the requirements of the FAC program will continue after EPU implementation.

Turbine Gland Steam

The main steam supply piping to gland seal steam is monitored under the FAC program. The EPU will result in an increase in steam flow, pressure and temperature in the turbine gland steam supply line. Monitoring per the FAC Program will continue after EPU implementation. Any increase in long-term wear of the piping due to EPU will be identified by the existing monitoring program.

FAC Program – Modeling for EPU

Prior to implementing the EPU, all of the PBNP CHECWORKS models will be updated to incorporate operating pressures and temperatures, fluid velocities and steam quality data derived from the EPU heat balances.

For several representative components, which are monitored within the flow-accelerated corrosion program, Tables 2.1.8-1, Comparison of Current and EPU Analytical Wear Rates (Unit 1), and Tables 2.1.8-3, Comparison of Current and EPU Analytical Wear Rates (Unit 2), provide a comparison of the wear rates for both existing full power plant conditions and the EPU conditions as analytically calculated by CHECWORKs for Unit 1 and Unit 2, respectively. CHECWORKs is used as guidance for examination selection and is important to determine areas which require additional examinations within the FAC program due to an increase in predicted wear rates. The components specified in Tables Tables 2.1.8-1, Comparison of Current and EPU Analytical Wear Rates (Unit 1), and Tables 2.1.8-3, Comparison of Current and EPU Analytical Wear Rates (Unit 2), were chosen as a representative sample of current high risk lines monitored within the FAC program. A decrease in the predicted FAC wear rate will have to be verified with examinations and an increase in the predicted FAC wear rates are used as an input to the FAC Examination scope during future outages.

Elements of the FAC program described above, including the component repair/replacement process and criteria, will continue to be utilized following the EPU implementation.

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

The License Renewal Safety Evaluation Report concludes that the PBNP Flow-Accelerated Corrosion Program is consistent with, but includes an exception to, the requirements of the Generic Aging Lessons Learned (GALL) Report, NUREG-1801 (Reference 8). The exception is a current commitment made as a result of License Renewal Requirements and contains specific requirements to expand scope on components inspected that are below a specified minimum allowable wall thickness. The NRC accepted and confirmed this exception in Item (CI) B2.1.11-1, NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, Section 1.6, Summary of Confirmatory Items, Page 1-17 (Reference 7). Changes to the piping/equipment included in the FAC Program as a result of the EPU are within the scope of the existing program and in compliance with program criteria. Therefore, the EPU does not affect the evaluation/conclusions in the License Renewal Safety Evaluation Report regarding the flow accelerated corrosion program, and no new aging effects requiring management are identified.

Results

The changes in flow rates, pressures, and temperatures due to EPU for the systems within the FAC program were reviewed. Based on the review, the existing scope of the FAC program is not changed. The piping and components currently being monitored will remain and will continue to be monitored per the FAC program. No new piping or component is required to be added to the FAC program. A comparison of the average wear rate for the current power condition and EPU condition indicates no significant change. The predicted remaining service life considering EPU conditions for selected piping indicates that there is ample service life remaining. Any piping requiring repair/replacement will be addressed per the FAC program.

2.1.8.3 Conclusion

PBNP has assessed the effects of EPU on the FAC analysis for the plant and concludes that the analysis has adequately addressed changes in the plant operating conditions on the FAC analysis. PBNP further concludes 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, PBNP finds the proposed EPU acceptable with respect to FAC.

2.1.8.4 References

1. Electric Power Research Institute (EPRI) Report NSAC-202L-R3, Recommendations for and Effective Flow-Accelerated Corrosion Program

2. NRC Generic Letter (GL) 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning, May 1989

3. NRC Bulletin BL 87-01, Thinning of Pipe Walls in Nuclear Power Plants, July 1987

4. Information Notice 93-21, Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs, May 1989

5. Electric Power Research Institute, CHECWORKS Steam/Feedwater Application for Flow Accelerated Corrosion

6. NUREG-1344, Erosion/Corrosion - Induced Pipe Wall Thining in US Nuclear Power Plants, April 01, 1989

7. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

8. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, dated September 2005

Table 2.1.8-1 Comparison of Current and EPU Analytical Wear Rates (Unit 1)

System	Line Description	Component ID	Component Geometry	Pipe Specification	CHECWORKS Average Wear-Rate Current Power (mils/year)	CHECWORKS Average Wear-Rate EPU Power (mils/year)
Main Steam	MS from A SG to HP Turbine	1MSEB01-015	Elbow	30" – 0.908" wall	8.741	4.316
Main Steam	MS from B SG to HP Turbine	1MSEB01-039	Orifice	30" – 0.908" wall	24.080	11.891
Main Steam	MS to MSR A	1MSEB04-028	75° Elbow	6" Sch 40	2.421	2.404
Main Steam	MS to MSR C	1MSEB04-077	Pipe	6" Sch 40	3.534	3.423
Condensate/ Feedwater	FWH4A/B line to Main Feed Pump Suction	1CSGB04-058	90° Elbow	20" Sch Std	3.403	3.369
Condensate/ Feedwater	FWH4B to common header	1CSGB04-074	90° Elbow	12" Sch Std	6.168	6.106
Heater Drain	FWH5A to FWH4A	1FDGB05-047	90° Elbow	8" Sch 40	2.662	2.662
Heater Drain	FWH5B to FWH4B	1FDGB05-017	90° Elbow	8" Sch 40	2.662	2.662
Feed Line	FWH5A to A Feed Reg Valve	1CSDB01-058A	Pipe	20" Sch 100	2.580	3.310
MSR Drain Lines	MSR A Drain to HDT	1FDHB01-010	Tee	8" Sch 40	2.651	2.588

Table 2.1.8-2 Comparison of Predicted and Measured Wall Thickness (Unit 1)

Line Description	Comp. ID	Pipe Specification	Nominal Thickness (inches)	CHECWORKS Average Wear-Rate (mils/year)	CHECWORKS Line Correction Factor(3)	Predicted Remaining Service life following U1R32 @EPU Wear Rate (Months)(1)	Predicted Thickness at Current Wear Rate at the end of Cycle 32 (inches)	NDE (UT or RT) Measured Thickness (inches)(2)
MS from A SG to HP Turbine	1MSEB01-015	30" – 0908" wall	0.908	Note 4	Note 4	Note 4	Note 4	0.940
MS from B SG to HP Turbine	1MSEB01-039	30" – 0908" wall	0.908	Note 4	Note 4	Note 4	Note 4	0.933
MS to MSR A	1MSEB04-028	6" Sch 40	0.280	2.483	0.142	145	0.252	0.251
MS to MSR C	1MSEB04-077	6" Sch 40	0.280	3.534	0.142	28	0.237	0.242
FWH4B to common header	1CSGB04-058	20" Sch Std	0.375	3.403	1.077	82	0.310	0.320
FWH4B to common header	1CSGB04-074	12" Sch Std	0.375	6.168	1.077	227	0.323	0.351
FWH5A to FWH4A	1FDGB05-047	8" Sch 40	0.322	2.662	1.195	1391	0.268	0.271
FWH5B to FWH4B	1FDGB05-017	8" Sch 40	0.322	2.662	1.195	1613	0.296	0.300
FWH5A to A Feed Reg VLV	1CSDB01-058A	20" Sch 100	1.281	2.580	1.746	850	1.772	1.240
MSR A Drain to HDT	1FDHB01-010	8" Sch 40	0.280	2.651	0.395	2222	0.201	0.256

1. Remaining Service Life is calculated during the Wear Rate Analysis (WRA). WRA then determines the projected remaining service life based on initial wall thickness, the water treatments in effect and the duration of operation. Given the duration of operation, a total lifetime wear is calculated and a thickness predicted for the duration of the model.
2. NDE (UT or RT) Measured Thickness is the minimum measurement during an inspection at one grid point.
3. Line Correction Factor (LCF) is the empirical model adjustment (up or down) to calibrate or correlate the predictions to the field data and determine absolute wear rates. A good correlation is 0.5 – 2.5 LCF.
4. Minimal wear has been detected. Monitoring will continue per the existing FAC program.

Table 2.1.8-3 Comparison of Current and EPU Analytical Wear Rates (Unit 2)

System	Line *Description*	*Component ID*	Component *Geometry*	Pipe *Specification*	CHECWORKS Average Wear-Rate Current Power *(mils/year)*	CHECWORKS Average Wear-Rate EPU Power *(mils/year)*
Main Steam	MS from A SG to HP Turbine	2MSEB01-034	Reducer	30" – 0.908" wall	4.132	4.848
Main Steam	MS from B SG to HP Turbine	2MSEB01-071	Reducer	30" – 0.908" wall	4.132	4.848
Main Steam	MS to MSR A	2MSEB04-020	90 Degree Elbow	6" Sch 40	2.138	3.830
Main Steam	MS to MSR D	2MSEB04-103	90 Degree Elbow	6" Sch 40	2.233	3.753
Condensate/ Feedwater	FWH4B to common header	2CSGB04-016	90 Degree Elbow	12" Sch Std	5.002	6.123
Condensate/ Feedwater	FWH4A to common header	2CSGB04-002	90 Degree Elbow	12" Sch Std	5.002	6.123
Heater Drain	FWH5A to FWH4A	2FDGB05-021	Tee	8" Sch 40	2.451	2.446
Heater Drain	FWH5B to FWH4B	2FDGB05-051	45 Degree Elbow	8" Sch 40	2.092	2.088
Turbine Gland Steam	Main Steam to Supply for Gland Steam	2MSEB03-014	90 Degree Elbow	3" Sch 40	0.080	1.166
Turbine Gland Steam	Main Steam to Air Ejectors	2MSEB03-149	Tee	3" Sch 40	1.819	1.353

1. *The percent increase in wear rate due to EPU for the lines are on lines categorized as* Susceptible Not Modeled in accordance with NSAC-202L-R3 Section 4.4.2 due to the high quality steam present.

Table 2.1.8-4 Comparison of Predicted and Measured Wall Thickness (Unit 2)

Line Description	Comp. ID	Pipe Specification	Nominal Thickness (inches)	CHECWORKS Average Wear-Rate (mils/year)	CHECWORKS Line Correction Factor(3)	Predicted Remaining Service life following U2R31 @EPU Wear Rate (Months)(1)	Predicted Thickness at Current Wear Rate at the end of Cycle 31 (inches)	NDE (UT or RT) Measured Thickness (inches)(2)
MS from A SG to HP Turbine	2MSEB01-034	30" – 0.908" wall	0.908	Note 4	Note 4	Note 4	Note 4	0.931
MS from B SG to HP Turbine	2MSEB01-071	30" – 0.908" wall	0.908	Note 4	Note 4	Note 4	Note 4	0.938
MS to MSR A	2MSEB04-020	6" Sch 40	0.280	2.138	1.829	20	0.210	0.248
MS to MSR D	2MSEB04-103	6" Sch 40	0.280	2.233	1.829	34	0.237	0.270
FWH4B to common header	2CSGB04-016	12" Sch Std	0.375	5.002	0.836	133	0.297	0.339
FWH4A to common header	2CSGB04-002	12" Sch Std	0.375	5.002	0.836	281	0.323	0.313
FWH5A to FWH4A	2FDGB05-021	8" Sch 40	0.322	2.451	0.808	2265	0.314	0.281
FWH5B to FWH4B	2FDGB05-051	8" Sch 40	0.322	2.092	0.808	1772	0.267	0.273
Main Steam to Supply for Gland Steam	2MSEB03-014	3" Sch 40	0.216	0.080	2.397	175	0.200	0.200
Main Steam to Air Ejectors	2MSEB03-149	1" Sch 80	0.179	1.819	2.397	2137	0.129	0.129

1. Remaining Service Life is calculated during the Wear Rate Analysis (WRA). WRA then determines the projected remaining service life based on initial wall thickness, the water treatments in effect and the duration of operation. Given the duration of operation, a total lifetime wear is calculated and a thickness predicted for the duration of the model.
2. NDE (UT or RT) Measured Thickness is the minimum measurement during an inspection from one grid point.
3. Line Correction Factor (LCF) is the empirical model adjustment (up or down) to calibrate or correlate the predictions to the field data and determine absolute wear rates. A good correlation is 0.5 – 2.5 LCF.
4. Minimal wear has been detected. Monitoring will continue per the existing FAC program.

2.1.9 Steam Generator Tube Inservice Inspection

2.1.9.1 Regulatory Evaluation

Steam generator (SG) tubes constitute a large part of the reactor coolant pressure boundary (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 PBNP 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), plant-specific alternate repair criteria, and redefined inspection boundaries.

The 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 RS-001. Additional review guidance is contained in PBNP Technical Specifications (TS) 3.4.13, RCS Operational Leakage, 3.4.17, Steam Generator (SG) Tube Integrity, and 5.5.8, Steam Generator Program, GL 95-03 (Reference 5) and Bulletin 88-02 (Reference 6) for degradation mechanisms, and NEI 97-06 (Reference 3) for structural and leakage performance criteria, all of which form the basis for alternate repair criteria or redefined inspection boundaries.

PBNP Current Licensing Basis

SG ISI is conducted in accordance with the SG Program required by PBNP Technical Specification 5.5.8 and Technical Requirements Manual 4.8, Steam Generator (SG) Program. A program of periodic SG inspections, designed to meet the guidance of EPRI SG Management Program (SGMP), is conducted to provide assurance of acceptable SG performance.

As part of the response to NRC Generic Letter 97-06, PBNP committed to develop a secondary side inspection program to ensure that degradation of SG internals does not adversely affect tube integrity (Reference 1).

The ISI program for the RCPB which includes SGs is discussed in FSAR Section 4.4, Tests and Inspections. Additional information is provided in FSAR Section 15.2.19, Steam Generator Integrity Program.

In addition to the evaluations described in the FSAR, the SG Integrity Program was evaluated for PBNP License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005(Reference 4)

The SG Program is in the scope of License Renewal.

2.1.9.2 Technical Evaluation

SG process parameters will change as a result of the proposed EPU. These parameters include temperatures, steam pressure, steam and feedwater flows, void fraction distributions, and circulation ratio. See LR Section 2.2.2.5, SG's and Supports, for a comprehensive assessment of the effects of EPU on the PBNP SGs.

The process of SG tube ISI and integrity assessment will not change as a result of the EPU. The tube integrity assessment process begins with an assessment of potential degradation mechanisms and selection of applicable non-destructive examination techniques that will be used during the ISI to determine if any degradation exists. After performing the ISI, a condition monitoring assessment is performed to determine if there may have been structural or leakage integrity issues during the operating interval since the previous inspection. After employing conservative growth rates, an operational assessment is performed to ensure that structural and leakage integrity performance criteria will be met during the operating interval until the next inspection. Tubes that are not projected to meet the structural and/or leakage integrity criteria are then removed from service by plugging, or repaired using an approved method.

Although the process parameter changes due to the EPU may impact the initiation and growth rates of various degradation mechanisms, these changes are considered per the above assessments, and will be incorporated into the selection of the type of NDE program action. RG 1.121 (Reference 2) analyses have been performed for PBNP at EPU conditions and are contained below.

2.1.9.2.1 RG 1.121 Analyses

The heat transfer area of SGs in a pressurized water reactor (PWR) nuclear steam supply system (NSSS) comprises over 50 % of the total primary system pressure boundary. The SG tubing, represents a primary barrier against the release of radioactivity to the environment. For this reason, conservative design criteria have been established for maintaining tube structural integrity under postulated design-basis-accident condition loadings in accordance with Section III of the ASME Code.

Over a period of time, under the influence of the operating loads and environment in the SG, some tubes may become degraded in local areas. Partially degraded tubes with a net wall thickness greater than the minimum acceptable tube wall thickness are satisfactory for continued service, provided that the minimum required tube wall thickness is adjusted to account for possible uncertainties in eddy current inspection and an operational allowance for continued tube degradation until the next scheduled inspection is provided.

Regulatory Guide 1.121, (Reference 2), describes an acceptable method for establishing the limiting safe conditions of degraded tubes beyond which tubes found degraded by the established in-service inspection program shall be removed from service. The level of acceptable degradation is referred to as the "repair limit."

Input Parameters, Assumptions, and Acceptance Criteria

EPU parameters pertinent to the RG 1.121 (Reference 2) analyses are provided in LR Section 1.1, NSSS Parameters. A uniform thinning mode of degradation in both the axial and circumferential directions for each PBNP unit for EPU conditions was assumed. The assumption of uniform thinning is generally regarded to result in a conservative structural limit for all flaw types occurring in the field.

NEI-97-06, Reference 3, defines a criterion for maintaining the SG tubes in a safe operating condition and, in particular, the structural integrity performance criterion (SIPC). The SIPC is based on ensuring that there is reasonable assurance that a SG tube will not burst during normal or postulated accident conditions. Meeting the performance criterion provides reasonable assurance that the SG tubing remains capable of fulfilling its safety function of maintaining RCPB integrity.

The structural integrity of the SG tubing is ensured by requiring that, based on analysis, testing, and in-service inspection, the tube bundle sustains, with recommended margins, the loads during normal operation and various postulated accident conditions.

Description of Analyses and Evaluations

Analyses were performed to define the structural limit for an assumed uniform thinning mode of degradation in both the axial and circumferential directions for each PBNP unit for EPU conditions. The allowable tube repair limit, in accordance with RG 1.121, (Reference 2) is obtained by incorporating into the minimum required thickness, a growth allowance for continued operation until the next scheduled inspection and also an allowance for eddy current measurement uncertainty. Analyses have been performed to establish the structural limit for the tube straight leg (free-span) region of the tube for degradation over an unlimited axial extent and for degradtion over a limited axial extent at the tube support plate (TSP) and anti-vibration bar (AVB) intersections.

This evaluation is applicable to the integrity of individual tubes with both general and local degradation. General degradation is treated by a nominal reduction in thickness over the tube's entire length. Local degradation is treated as a uniform loss of wall thickness in both the circumferential and axial directions. The assumption of uniform thinning is a conservative structural limit for all flaw types occurring in the field, including partial depth axial and partial depth circumferential cracks. Criteria are categorized into three tube regions, anti-vibration bar (AVB) intersections, support plate intersections (including tube support plates and flow distribution baffles), and straight leg regions of the tube.

Regulatory Guide 1.121 Evaluation Results

A summary of the tube structural limits determined by the RG 1.121 (Reference 2) analysis is provided in Tables 2.1.9-1, PBNP Unit 1 – Model 44F Summary of Tube Structural Limits (Regulatory Guide 1.121 Analysis), and Tables 2.1.9-2, PBNP Unit 2 – Model Δ47 Summary of Tube Structural Limits (Regulatory Guide 1.121 Analysis), for Units 1 and 2, respectively. Each of the structural limits is governed by maintaining a safety factor of three against burst under normal steady-state full power operation at EPU conditions. The corresponding repair limit is established by subtracting an allowance for eddy current uncertainty and continued growth from the values in Tables 2.1.9-1 and 2.1.9-2.

Structural limits that could potentially be used in an operational assessment to address circumferential cracks were evaluated. The analysis results show that the structural limits of the Regulatory Guide 1.121 (Reference 2) analysis are not affected by the SIPC requirements, and the Tables 2.1.9-1 and 2.1.9-2 limits apply.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

While the proposed EPU conditions will change process parameters, there are no changes being made to the SGs of a material or structural nature that would impact ISI. The potential effects of process parameters are subject to an existing aging management review program, the SG Surveillance Program as accepted by the NRC in NUREG-1839 (Reference 4), which remains valid for EPU conditions. No unevaluated material changes to the SGs are being made that would change the scope of the SGs with respect to license renewal. Therefore, no new aging effects requiring management are identified.

2.1.9.3 Conclusions

PBNP has evaluated the effects of the proposed EPU on SG tube integrity and concludes that the evaluation has adequately assessed the continued acceptability of the plants' Technical Specifications under the proposed EPU conditions and has identified appropriate degradation management inspections to address the effects of change in temperature, differential pressure, and flow rates on SG tube integrity. PBNP further concludes that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06 and Regulatory Guide 1.121 following implementation of the proposed EPU. Therefore, PBNP finds EPU acceptable with respect SG Inservice Inspection.

2.1.9.4 References

1. Response to NRC Generic Letter 97-06, Degradation of Steam Generator Internals, dated March 30, 1998

2. Regulatory Guide 1.121, Bases for Plugging Degraded PWR Steam Generator Tubes (for comment), August 1976

3. NEI 97-06, Revision 2, Steam Generator Program Guidelines, May 2005

4. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

5. NRC Generic Letter (GL) 95-03, Circumferential Cracking of Steam Generator Tubes, April 28, 1995

6. NRC Bulletin (BL) 88-02, Rapidly Propagating Fatigue Cracks in Steam Generator Tubes, February 05, 1988

Table 2.1.9-1 PBNP Unit 1 – Model 44F Summary of Tube Structural Limits (Regulatory Guide 1.121 Analysis)

Location/Wear Scar Length	Parameter	High T_{avg}	Low T_{avg}
Straight Leg (≥ 1.5")	t_{min} (inch)	$[]^{(a,c)}$	$[]^{(a,c)}$
	Structural Limit (%)[1]	$[]^{(a,c)}$	$[]^{(a,c)}$
FDB[3]/0.75"	t_{min} (inch)	$[]^{(a,c)}$	$[]^{(a,c)}$
	Structural Limit (%)[1]	$[]^{(a,c)}$	$[]^{(a,c)}$
TSP/1.12"	t_{min} (inch)	$[]^{(a,c)}$	$[]^{(a,c)}$
	Structural Limit (%)[1]	$[]^{(a,c)}$	$[]^{(a,c)}$
AVB/0.65"[2]	t_{min} (inch)	$[]^{(a,c)}$	$[]^{(a,c)}$
	Structural Limit (%)[1]	$[]^{(a,c)}$	$[]^{(a,c)}$

1. Structural Limit = $[(t_{nom} - t_{min})/t_{nom}] \times 100\%$
   $t_{nom} = []^{(a,c)}$ in
2. For tube/AVB tangent points, straight leg structural limits apply. Tube/AVB tangent points correspond to Row 10 for the inner set of AVBs, and Row 13 for the outer set of AVBs.
3. Flow Distribution Baffle (FDB)

Table 2.1.9-2 PBNP Unit 2 – Model Δ47 Summary of Tube Structural Limits (Regulatory Guide 1.121 Analysis)

Location/Wear Scar Length	Parameter	High T_{avg}	Low T_{avg}
Straight Leg (≥ 1.5")	t_{min} (inch)	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
	Structural Limit (%)[1]	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
FDB[4]/0.75"	t_{min} (inch)	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
	Structural Limit (%)[1]	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
TSP/1.12"	t_{min} (inch)	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
	Structural Limit (%)[1]	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
AVB/0.70"[2,3]	t_{min} (inch)	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
	Structural Limit (%)[1]	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
AVB/0.90"[2,3]	t_{min} (inch)	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$
	Structural Limit (%)[1]	$[\ ]^{(a,c)}$	$[\ ]^{(a,c)}$

1. Structural Limit = $[(t_{nom} - t_{min})/t_{nom}] \times 100\%$
   $t_{nom} = [\ ]^{(a,c)}$ in
2. For tube/AVB tangent points, straight leg structural limits apply. Tube/AVB tangent points correspond to Row 15 for the inner set of AVBs, Row 27 for the intermediate set of AVBs, and Row 49 for the outer set of AVBs. Straight leg structural limits also apply to tube/AVB intersections rows 16 through 19.
3. The tube repair limits and minimum thickness specified for the AVB with wear scars less than 0.9 inch but greater than 0.7 inch applies to tube/AVB intersections rows 20 through 26, inner AVBs and rows 28 through 36 intermediate AVBs. The tube repair limits and minimum thickness specified for wear scars less than or equal to 0.7 inch applies to inner AVB intersections for rows 27 and above, intermediate AVB intersections, rows 37 and above and all outer AVB intersections.
4. Flow Distribution Baffle (FDB)

2.1.10 Steam Generator Blowdown System

2.1.10.1 Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of steam generator tubes. The steam generator blowdown (SGBD) system removes steam generator secondary-side impurities and thus, assists in maintaining acceptable secondary-side water chemistry in the steam generators. The design basis of the SGBD system includes consideration of expected and design flows for all modes of operation. The PBNP review focused on the ability of the SGBD system to remove particulate and dissolved impurities from the steam generator secondary side during normal operation, including anticipated operational occurrences (main condenser in-leakage and primary-to-secondary leakage).

The NRC's acceptance criteria for the SGBD system are based on GDC-14, insofar as it requires that the reactor coolant pressure boundary 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.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the general design criteria (GDC) used during the licensing of PBNP predates those provided today in 10 CFR 50 Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR Sections 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-14 is as follows:

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

FSAR sections that address the SGBD system include:

- FSAR Section 10.1, Steam and Power Conversion, addresses the functional capability of the SGBD system.
- FSAR Section 11.5, Discharge Effluent Radiation Monitoring, requires radioactivity monitoring of discharge flow paths prior to their final release point.
- FSAR Section 5.2, containment isolation, discusses features to isolate the SGBD lines penetrating containment to ensure that the total leakage of activity will be within design limits in the event of an accident.
- FSAR Section 15.2.11, Flow-Accelerated Corrosion (FAC) Program, addresses this concern in single and two phase flow systems consistent with the requirements of EPRI guidelines in NSAC-202L-R3.
- FSAR Section 15.2.24, water chemistry control program, describes aging management program to control secondary water chemistry.

Additional SGBD system details are provided in FSAR Section 5.4.2.1, Pipe Rupture – Penetration Integrity, Appendix A.2, High Energy Line Pipe Failure Outside Containment, Appendix A.5.2, Seismic Classification of Structures and Equipment, and Appendix I, Evaluation of Radioactive Releases from Point Beach Nuclear Plant.

In addition to the information described in the FSAR, the PBNP SGBD system was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The above SER, discusses the portion of SGBD system directly connected to the steam generators in SER Section 2.3.4 Main and Auxiliary Steam. Plant programs used to manage the aging effects associated with the steam generators are discussed in Section 3.1 of the SER.

2.1.10.2 Technical Evaluation

Introduction

The SGBD system is discussed in FSAR Sections 5.2, Containment Isolation System, 10.1, Steam and Power Conversion System, 11.5, Liquid Waste Management System - Accidental Release-Recycle or Waste Liquid, and 15.2, Aging Management Program Descriptions. The SGBD system design functions are:

- To blow down fluid at a continuous rate for chemistry control of each steam generator to minimize corrosion and degradation of the steam generator tubes. The SGBD system is provided to maintain the water chemistry within the prescribed operating limits and reduce the radiation content to acceptable levels before the blowdown can be returned to the condensate system or released to the environment
- To blow down fluid at a maximum flow rate of 29,000 lb/hr per SG with a maxium of 40,000 lb/hr to the blowdown tank to prevent overflow
- To recover both the blowdown water and its heat capacity
- To provide a closed system inside containment and provide for containment isolation of blowdown lines penetrating containment

Continuous blowdown from the steam generators reduces accumulation of solids that result from the boiling process. The normal blowdown flow rate that has proven to be effective is approximately 15,000 lbs/hr continuous flow for each steam generator. The blowdown flow rates required during plant operation are based on chemistry control and tube-sheet sweep requirements to control the buildup of solids. The blowdown flow rate required to control chemistry and the buildup of solids in the steam generators is tied to allowable condenser in-leakage, total dissolved solids in the plant service water, and the allowable primary to secondary leakage. Since these variables are not impacted by EPU, the blowdown required to control secondary chemistry and steam generator solids will not be impacted by EPU.

SG chemistry treatment is all-volatile chemistry (AVT). Heat recovery exchangers for the SGBD allow for heat recovery. Normal discharge of SGBD is to the service water return header. During operation, if there is a radiological concern due to primary to secondary leakage, the SGBD can be processed by to waste condensate demineralizers. EPU results in a SGBD temperature of 136°F dowmstream of the heat exchangers, assuming a peak CW inlet temperature and normal 100% power operation.

The SGBD system sample lines as well as blowdown lines are provided with redundant valves and associated apparatus. For EPU conditions, no modification to these piping and valves is required. Therefore, the containment isolation function is not impacted. The testing of the functional operability of valves and associated apparatus during periods of reactor shutdown remains unchanged for the EPU condition. Local leak tests of containment isolation valves are performed as required during periods of reactor shutdown. The safety related valve closure and testing requirements (containment isolation) are addressed in LR Section 2.2.4, Safety-Related Valves and Pumps.

Description of Analyses and Evaluations

The SGBD system and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations were performed for an analyzed core power of 1800 MWt. The existing design parameters of the systems/components listed below were compared with the EPU conditions:

- Maximum blowdown flow rate (29,000 lb/hr per SG) with a maximum of 40,000 lb/hr to the blowdown tank to prevent overflow
- Operating and design pressures and temperatures
- Monitoring of liquid effluents (SGBD) prior to release, is addressed in LR Section 2.10.1, Occupational and Public Radiation Doses.
- Fluid velocities and the potential for increased erosion/corrosion. The erosion/corrosion monitoring program is evaluated in LR Section 2.1.8, Flow-Accelerated Corrosion.
- Seismic Qualification and dynamic qualification is addressed in LR Section 2.2.5, Seismic and Dynamic Qualification of Mechanical and Electrical Equipment.
- Safety related valve closure and testing requirements (containment isolation) are addressed in LR Section 2.2.4, Safety-Related Valves and Pumps.
- Review of piping/component supports is described in LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports.
- Protection against dynamic effects, including missiles, pipe whip and discharging fluids is addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, and LR Section 2.5.1.3, Pipe Failures
- Environmental qualification of the containment isolation valves is addressed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment.

Results

The increased steam and feedwater flow rates at EPU conditions do not significantly affect the concentration of impurities throughout the turbine cycle nor increase the effect of the impurities on the steam generators. Blowdown rate subsequent to implementing EPU will be unchanged. Therefore, no changes to the design SGBD flow rates or operating modes are needed as a result of the EPU.

For the EPU, the steam generator blowdown flow will be maintained between 30,000 lb/hr normal flow and 40,000 lb/hr maximum flow for SG hot soaks per steam generator and unit startup since the steam generator impurities are not expected to be significantly higher at EPU conditions.

Since the flow remained unchanged and the pressure in the steam generator blowdown piping at EPU decreased slightly, the potential for erosion/corrosion will not increase due to the EPU. This is further discussed in LR Section 2.1.8, Flow-Accelerated Corrosion. The blowdown system is now, and will continue to be monitored by the Erosion/Corrosion Program after EPU.

At EPU conditions, the operating temperatures increase slightly and pressures in the steam generators, SGBD tank and interconnecting piping and valves decreases slightly due to the higher T_{avg} and lower steam generator operating pressure. However, the existing design pressure and temperature of the steam generators, 1085 psig/555°F, remain bounding for EPU conditions since these values are based on the no-load operating condition which does not change at EPU. Therefore, the design conditions for the SGBD piping and components connected to the SGs also remain bounded for EPU conditions.

The SGBD lines penetrating containment are provided with air-operated isolation valves which are designed to close for containment isolation post-accident. The maximum blowdown flow rates and pressures experienced by these valves at EPU conditions do not exceed the existing valve design capabilities and; therefore, these valves continue to meet their containment isolation design function.

The effects of the proposed EPU on the SGBD system have been evaluated with the conclusion that they continue to meet the PBNP current licensing basis requirements with respect to the reactor coolant pressure boundary. EPU will not affect the plants extremely low probability, of abnormal leakage, of rapidly propagating fracture, and of gross rupture, of the reactor coolant pressure boundary. The ability of the SGBD system to remove particulate and dissolved impurities from the steam generator secondary side during normal operation, including anticipated operational occurrences, will not be affected. No modifications to the SGBD system are required for EPU. Therefore, the proposed EPU is acceptable with respect to the SGBD system.

FSAR Section 5.2, Containment Isolation System, the containment isolation function of the SGBD system provides isolation valves as necessary for lines penetrating the containment to assure at least two barriers for redundancy against leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident. These barriers, in the form of isolation valves or closed systems, are defined on an individual line basis. EPU does not change these functions.

FSAR Section 15.2.11, Flow-Accelerated Corrosion (FAC) Program addresses this concern in single and two phase flow systems. The SGBD piping will continue to be monitored under the FAC Program (LR Section 2.1.8, Flow-Accelerated Corrosion).

FSAR Section 15.2.24, Water Chemistry Program, discusses Water Chemistry Control Program. The water chemistry program manages aging effects by controlling the internal environment of system and components. Primary, borated and secondary water systems are included in the scope of the program. EPU does not affect this Water Chemistry Control Program.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The SGBD operating flow rates and process conditions are within the original design parameters of the system. There are no system/component modifications necessary. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no new or previously unevaluated materials in the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.1.10.3 Conclusions

PBNP has reviewed the evaluation of the effects of the proposed EPU on the SGBD system and concludes that the evaluation has adequately addressed changes in system parameters and impurity levels and their effects on the SGBD system. PBNP further concludes that the evaluation has demonstrated that the SGBD system will continue to be acceptable and will continue to meet the requirements of GDC 9 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the SGBD system.

2.1.10.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.1.11 *Chemical and Volume Control System*

2.1.11.1 Regulatory Evaluation

The chemical and volume control system (CVCS) and boron recycle (BS) system provide means for:

- Maintaining water inventory and quality in the reactor coolant system (RCS)
- Supplying seal-water flow to the reactor coolant pumps (RCPs) and pressurizer auxiliary spray
- Controlling the boron neutron absorber concentration in the reactor coolant
- Controlling the primary water chemistry, reducing coolant radioactivity level, and recycling coolant for demineralized water makeup for normal operation

Note: PBNP does not use CVCS to provide high pressure injection flow for emergency core cooling in the event of postulated accidents.

PBNP reviewed the safety-related functional performance characteristics of CVCS components.

The NRC's acceptance criteria are based on GDC 14 insofar as it requires that the reactor coolant pressure boundary be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and on GDC 29, insofar as it requires that the reactivity control systems be designed to ensure an extremely high probability of accomplishing their safety functions in anticipation of operational occurrences.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDCs for 10 CFR 50 Appendix A GDC 14 and 29 are as follows:

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

CRITERION: Two independent reactivity control systems, preferably of different principles, shall be provided. (PBNP GDC 27)

In addition to the reactivity control achieved by the rod cluster control (RCC) described in FSAR Section 3.1, Reactor, General Design Criteria, reactivity control is provided by the CVCS which regulates the concentration of boric acid solution neutron absorber in the reactor coolant system. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

CRITERION: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (PBNP GDC 30)

The reactivity control systems provided are capable of making and holding the core subcritical, under accident conditions, in a timely fashion with appropriate margins for contingencies. Normal reactivity shutdown capability is provided within 2.2 seconds following a trip signal by control rods with soluble neutron absorber (boric acid) injection used to compensate for the long term xenon decay transient for the plant cooldown.

Boric acid may be pumped from the boric acid tanks by one of the boric acid transfer pumps (or via gravity feed from the RWST) to the suction of one of three charging pumps with inject boric acid into the reactor coolant. Any charging pump and either boric acid transfer pump can be operated from diesel generator power on loss of outside power. Boric acid can be injected by one charging pump supplied by one boric acid transfer pump at a rate which shuts the reactor down hot with no rods inserted in less than 120 minutes. In 120 additional minutes, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the equilibrium operating level does not begin until approximately fifteen hours after shutdown. If two boric acid transfer pumps are available, these time periods are reduced. Additional boric acid injection is employed if it is desired to bring the reactor to cold shutdown conditions.

The injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The CVCS System performs the following safety related Functions:

a. CVCS System piping and components interfacing with pressure boundaries for the (1) reactor coolant system, (2) component cooling water system, (3) safety injection syst (refueling water storage tank), and (4) residual heat removal system shall maintain the pressure boundary integrity to support the safety function of these systems.

b. CVCS System containment isolation valves and portions of the CVCS System that function as a closed system outside containment shall maintain containment integrity following accidents that require containment isolation.

Additional Chemical and Volume Control System details are provided in FSAR Sections 4.1, Reactor Coolant System, Design Basis, 5.2, Containment Isolation System, 5.7, Containment System Structure, Tests and Inspections and 9.3, Chemical and Volume Control System.

In addition to the evaluations described in the FSAR, CVCS was evaluated for plant license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the CVCS is described in Section 2.3.3.1, Regulatory Evaluation. The programs used to manage the aging effects associated with auxiliary systems are discussed in Section 3.3 of the PBNP License Renewal SER.

2.1.11.2 Technical Evaluation

2.1.11.2.1 Introduction

The CVCS is described in FSAR Section 9.3, Chemical and Volume Control System. The system is designed to perform the following functions.

- To control the reactor coolant inventory, chemistry conditions, activity level, and boron concentration
- To provide seal-water injection flow to the reactor coolant pumps
- To process reactor coolant effluent for reuse of boric acid and makeup water
- To provide pressurizer auxiliary spray
- To maintain containment integrity following accidents that require containment isolation

To perform these functions, continuous feed and bleed is maintained between the RCS and the CVCS. Water is let down from the RCS, through a regenerative heat exchanger (HX), to minimize thermal loss from the RCS. The pressure is reduced through orifices and further cooling occurs in the non-regenerative HX followed by a second pressure reduction. Water is returned to the RCS by the charging system, which also provides seal injection flow to the reactor coolant pumps.

The chemistry of the letdown flow may be altered by passing the flow through demineralizers that remove ionic impurities. A filter removes solids, and the gases dissolved in the coolant are removed in the volume control tank. The boric acid concentration in the coolant is changed by the reactor makeup portion of the CVCS as required for reactivity control.

2.1.11.2.2 Description of Analysis and Evaluations

The CVCS was evaluated to ensure the system is capable of performing its intended functions for the range of Nuclear Steam Supply System (NSSS) design parameters approved for EPU (LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate). The evaluation was performed for a NSSS thermal power of 1806 MWt.

The changes in NSSS design parameters that could potentially affect the CVCS design bases functions include the increase in core power and the allowable range of RCS full-load design temperatures. The increase in core power and the allowable range of RCS full-load design temperatures may also affect the CVCS design bases requirements related to the core re-load boron requirements. Additionally, the allowable range of RCS full load design temperatures may affect the heat loads that the CVCS heat exchangers must transfer to the component cooling water system and in the case of the regenerative heat exchanger to the charging flow.

Regenerative Heat Exchanger

The regenerative HX cools the normal letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 559.5°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F (LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1, NSSS Design Parameters for PBNP Units 1 and 2 Extended Power Uprate). The no-load RCS temperature has not changed. Although the full-load EPU T_{cold} temperature will decrease below the current values, they will remain less than the design basis T_{cold} and no load T_{cold} values. Therefore, the performance of the regenerative HX remains essentially unchanged due to EPU and is acceptable at EPU conditions with no plant changes required.

Non-Regenerative Heat Exchanger

The non-regenerative HX cools the letdown flow from the regenerative HX. Since the change in performance of the regenerative HX is essentially unchanged at EPU conditions, as discussed in the previous section, there is essentially no effect on the performance of the non-regenerative HX. Minor differences in letdown temperature can easily be accommodated within the capability of the non-regenerative HX cooling water temperature control valve, TCV-130. Therefore, it is concluded that acceptable non-regenerative HX performance is provided at the EPU conditions, with no plant changes required.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools the quantity of reactor coolant letdown equal to the nominal injection rate through the labyrinth seals of the reactor coolant pumps, if letdown through the regenerative heat exchanger is blocked. Accordingly, the excess letdown HX cools the excess letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the excess letdown HX is 559.5°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F. Since the no-load RCS temperature has not changed, and the full-load EPU T_{cold} temperature remains below the no load temperature, the performance of the excess letdown HX is acceptable at EPU conditions with no plant changes required.

Seal Water Heat Exchanger

The seal water HX cools the seal return flow from the two RCP No. 1 seals and the excess letdown flow (from the excess letdown HX) if it is in service. The RCP heat load (including the thermal barrier HX) is a function of RCS T_{cold} temperature, while the excess letdown heat load is a function of excess letdown HX performance. Since the no-load RCS temperature has not changed and the full-load EPU T_{cold} temperature remains below the no load temperature, the performance of the seal water HX is acceptable at EPU with no plant changes required.

Charging, Letdown, and RCS Makeup (Boration, Dilution, Purification, and N-16 Delay Time)

As discussed in the previous sections for the various CVCS HXs, there are essentially no effects on their performance at the EPU conditions. Therefore, the charging and letdown flows at EPU conditions are essentially unchanged. With no change in letdown and charging flows, the following CVCS functions are not impacted by EPU: providing seal water to the Reactor Coolant Pumps, providing pressurizer auxiliary spray, adding chemicals (LiOH, Hydrogen) to RCS for chemistry control and delivering coolant to the boron recycle system and effluent re-processing.

The flow capacity performance of the RCS makeup system is independent of the change in RCS conditions resulting from the EPU conditions. However, the makeup system also relies on storage capacity of various sources of water including primary makeup water and boric acid solutions from both the boric acid storage tanks and the refueling water storage tank (RWST).

Primary makeup water is used to dilute RCS boron, to provide positive reactivity control, or to blend concentrated boric acid to match the prevailing RCS boron concentration during RCS inventory makeup operations. Since the flow capacity performance of the RCS makeup system is independent of the change in RCS conditions resulting from the EPU conditions as discussed above, the EPU does not affect the capability of the makeup system to perform these system functions.

The boric acid storage tanks (BAST) and RWST provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The EPU is expected to have a small effect on the boration requirements that must be provided by the CVCS boration capabilities. The maximum expected RCS boron concentrations are within the capability of the CVCS. The Westinghouse reload safety evaluation (RSE) process is designed to address boration capability for routine plant changes, such as core reloads, and infrequent plant changes such as a plant uprating that result in a change to core operating conditions and initial core reactivity. Therefore, boration capability will be addressed during the RSE process for each reload cycle.

The CVCS letdown flow is fixed and charging flow is varied to control pressurizer water level and RCS inventory. The pressurizer water level is programmed as a function of power level to accommodate RCS coolant expansion. Accordingly this programmed level is being changed based on the EPU NSSS design parameters. However, this change has no impact on the ability of the CVCS to maintain RCS inventory which is accomplished via letdown, charging and makeup.

Analyses have indicated the potential for an increase in crud buildup at EPU. The expected increase in the required charging and letdown flow to provide the additional RCS purification/cleanup is within the current charging and letdown flow capabilities.

The letdown flow path is routed inside containment such that there is adequate decay of N-16 before the letdown fluid leaves the containment building. Since letdown flow is essentially unchanged, as discussed in the previous paragraphs, this radiation protection feature of the CVCS is not affected by the EPU. However it is noted that the letdown line and excess letdown line radiation dose rates from N-16 (for example, amount of N-16) will increase proportional to the increase in reactor power level.

Refer to LR Section 2.2.2, Pressure-Retaining Components and Component Supports for an evaluation of the CVCS Class 1 piping including RCS nozzles and thermal sleeves.

Evaluation of Impact on Renewal Plant Operating License, Evaluations and License Renewal

EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the CVCS at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus no new aging effects requiring management are identified and the aging management programs credited for the CVCS and accepted by the NRC in NUREG-1839 remain valid for EPU conditions.

2.1.11.3 Results

The evaluations of the CVCS charging, letdown, and RCS makeup performance show the CVCS is acceptable at the EPU conditions, with no plant changes. Accordingly, the performance of the following CVCS functions (which are accomplished via charging, letdown, and makeup) are acceptable at EPU conditions with no plant changes.

- Control of RCS inventory and activity levels.
- Control of water chemistry required to ensure reactor coolant pressure boundary material integrity in accordance with PBNP current licensing basis requirements with respect to PBNP GDC 9.
- Control of RCS soluble boron required to control reactivity in accordance with PBNP current licensing basis requirements with respect to PBNP GDCs 27 & 30.
- Provision of seal water injection for the reactor coolant pumps (RCPs).
- Pressurizer auxiliary spray.
- Deliverance of water to the CVCS boron-recycle subsystem.
- Maintain containment integrity following accidents that require containment isolation.

The CVCS boration capability is addressed during the Reload Safety Evaluation (RSE) process (currently incorporated into PBNP Technical Specifications) for each core reload cycle. The performance of the CVCS components including valves and piping that support containment isolation are not affected by change in RCS design parameters resulting from EPU.

There is a small increase in letdown line dose rates from N-16, proportional to the increase in reactor power level. This small increase has been evaluated in LR Section 2.10.1, Occupational and Public Radiation Doses, as being acceptable.

Refer to LR Section 2.2.2.1, NSSS Piping, Components and Supports, for results of the evaluation of the CVCS Class 1 piping including RCS nozzles and thermal sleeves.

The CVCS support functions provided by the sampling system and waste disposal system are not affected by the change in RCS conditions resulting from the EPU.

2.1.11.4 Conclusions

PBNP has reviewed the evaluation of the effects of the EPU on the CVCS and boron recovery system and concludes that the evaluation adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS and boron recovery system. PBNP further concludes that the CVCS and boron recovery system continue to be acceptable and continue to meet the requirements of PBNP GDC 9, 27, and 30 following implementation of the EPU. Therefore, PBNP finds the EPU acceptable with respect to the CVCS.

2.1.11.5 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

2.2.1.1 Regulatory Evaluation

Safety-related structures, systems, and components important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. PBNP conducted a review of pipe rupture analyses to ensure that safety-related structures, systems, and components (SSCs) important to safety are adequately protected from the effects of pipe ruptures. The PBNP review covered:

- The implementation of criteria for defining pipe break and crack locations and configurations
- The implementation of criteria dealing with special features, such as augmented In-service inspection programs or the use of special protective devices such as pipe-whip restraints
- Pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects
- The design adequacy of supports for structures, systems, and components provided to ensure that the intended design functions of the structures, systems, and components will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings

The PBNP review focused on the effects that the proposed EPU may have on the above four items.

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 the Standard Review Plan (SRP), Section 3.6.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

Specifically, the adequacy of PBNP's safety-related structures, systems and components with respect to potential pipe ruptures and their associated dynamic effects are based on conformance to:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures, other than a rupture of the Reactor Coolant System Piping. (PBNP GDC 40)

This plant-specific General Design Criterion is very similar to 10 CFR 50 Appendix A GDC 4.

Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures may be excluded from the design basis when appropriate analyses reviewed and approved by the NRC demonstrate that the probability of fluid system piping ruptures is extremely low, under design basis conditions. Analyses have been completed for the Reactor Coolant Loop piping, the Pressurizer Surge Line, the Accumulator Injection Line piping including a portion of the RHR return line piping, the RHR return line and the RHR suction line. The NRC has approved the analyses. As such, the original design features of the facility to accommodate the dynamic effects of a pipe rupture associated with these lines are no longer applicable.

The use of leak-before-break is described in LR Section 2.1.6, Leak-Before-Break, of this report.

A loss-of-coolant accident or other plant equipment failure might result in dynamic effects, including effects of missiles, pipe whipping, and discharging fluids. The steam generators are supported, guided, and restrained in a manner which prevents rupture of the secondary side of a generator, the steam pipelines, and the feedwater piping as a result of forces created by a Reactor Coolant System pipe rupture. These supports, guides, and restraints also prevent rupture of the primary side of a steam generator as a result of forces created by a steam or feedwater pipeline rupture. The mechanical consequences of a pipe rupture are restricted by design such that the functional capability of the engineered safety features is not impaired.

Injection paths leading to unbroken reactor coolant loops are protected against damage as a result of the maximum reactor coolant pipe rupture by layout and structural design considerations. Injection lines penetrate the main missile barrier, which is the loop compartment wall, and the injection headers are located in the missile protected area between the loop compartment wall and the containment wall. Individual injection lines, connected to the injection header, pass through the barrier and then connect to the loops. Separation of the individual injection lines is provided to the maximum extent practicable. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the loop compartment is possible.

The containment structure is capable of withstanding the effects of missiles originating outside the containment and which might be directed toward it so that no loss-of-coolant accident can result.

All piping systems which penetrate the containment structure are anchored at the penetration. Penetrations for lines containing high pressure or high temperature fluids (steam, feedwater, and blowdown lines) are designed so that the containment is not breached by a hypothesized pipe rupture. All lines connected to the primary coolant system that penetrate the containment are also anchored in the secondary shield walls (i.e., walls surrounding the steam generators and reactor coolant pumps). These anchors are designed to with stand the thrust, moment, and torque resulting in a hypothesized rupture of the attached pipe.

Conformance to the requirements of PBNP GDC-40, ensuring that safety related structures, systems and components are adequately protected with respect to pipe ruptures and their associated dynamic effects, is addressed in FSAR Section 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 5.1, Containment System Structure, 6.1, Engineered Safety Features, Criteria, 9.0, Auxiliary and Emergency Systems, and Appendix A.2, High Energy Pipe Failure Outside Containment.

Postulated Piping Failures in Fluid Systems Outside Containment

Pipe break criteria define a high energy fluid system as one where the maximum operating temperature is greater than or equal to 200°F and the maximum operating pressure is greater than or equal to 275 psig. An effects oriented approach to determine the acceptability of plant response to pipe breaks was performed (i.e., each structure, system and component which must function to mitigate the effects of the pipe break and to safely shut down the plant was examined to determine its susceptibility to the effects of the postulated break. Additional details are provided in FSAR Appendix A.2, High Energy Pipe Failure Outside Containment.

A detailed discussion of postulated pipe failures and PBNP mitigating strategies is provided in LR Section 2.5.1.3, Pipe Failures.

FSAR Appendix A.5, Seismic Design Analysis, provides details with respect to the seismic qualification of piping and piping components.

In addition to the evaluations described in the FSAR, PBNP's pipe rupture components were evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the equipment and components credited with mitigating the effects of pipe ruptures and associated dynamic effects are described in Section 2.4 and the programs credited with managing that equipment aging are described in Section 3.5.2.

2.2.1.2 Technical Evaluation

Introduction

PBNP GDC-40 requires that safety related structures, systems, and components be designed to accommodate the dynamic effects of a postulated pipe rupture, including pipe whip dynamic effects and jet thrust and impingement effects.

Refer to LR Section 2.5.1.3, Pipe Failures, for a discussion of plant design for protection from piping failures outside containment.

Safety-related structures, systems, and components (SSCs) could be impacted by the pipe-whip dynamic effects of a pipe rupture. A review of pipe rupture analyses was conducted to ensure that those SSCs are adequately protected from the effects of pipe ruptures. The review covered:

- The implementation of criteria for defining pipe break and crack locations and configurations
- The implementation of criteria dealing with special features, such as augmented in-service inspection programs or the use of special protective devices such as pipe-whip restraints
- Pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects

- The design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will remain acceptable as a result of pipe-whip or jet impingement loadings

The review focused on the effects that the proposed EPU may have on the above items.

The following licensing basis change in methodology was used in the High Energy Line Break (HELB) evaluations and requires NRC approval prior to implementation.

The guidance of GL 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987, (Reference 2) was used for the evaluation of pipe rupture location and dynamic effects. The stress thresholds for identifying break and crack locations from MEB 3-1 (Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2, dated June 1987) were also adopted. The determination of stress values for rupture postulation evaluations were calculated using ASME Section III, 1986 edition requirements in lieu of stress intensification factors. That is, the ASME Code Equations 9 and 10 stresses were calculated with the use of stress indices for deadweight and OBE resultant moments (B_2 indices) and longitudinal pressure (B_1 indices) and used stress intensification factors (i) for thermal expansion moments only.

ASME Code Cases N-318-5, Procedure for Evaluation of the Design of Rectangular Cross Section Attachments on Class 2 & 3 Piping, dated April 1994, (Reference 3) and N-392-1, Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 2 & 3 Piping, dated December 1989, Reference 4) were used to calculate the local stresses due to shear lugs and hollow circular attachments, respectively, since these are the latest versions of the applicable Code Cases. The method for calculating local stresses at the elbow lugs is in accordance with 1979 PVP Spring Conference Paper 79-PVP-51 (Stresses in Elbows Created by Supported Lug Load, T.K. Emera and E.C. Rossow).

The use of ASME Code Cases N-318-5 and N-392-1 were not intended to evaluate the Integral Welded Attachments (IWA's) or the weld between the IWA and the pipe, but rather calculate the local stresses for use in evaluating HELB locations. The local stresses from the IWA analysis are added to the piping system stresses using ASME B&PV Code Section III, Class 2 and 3, Equations 9 plus 10 to obtain the combined stresses and compare them to the threshold stress limits as given below to determine the break locations. The crack locations were determined by the same approach as the break location except that the coefficient on the right side of the equation is 0.4 instead of 0.8 as shown below.

$$\{LS+B_1PD_O/2t+B_2M_{DW}/Z+B_2M_{OBE}/Z+i\ M_{TH}/Z > 0.8\ (1.8S_h+S_A) \text{ for break locations}\}$$

$$\{LS+B_1PD_O/2t+B_2M_{DW}/Z+B_2M_{OBE}/Z+i\ M_{TH}/Z > 0.4\ (1.8S_h+S_A) \text{ for crack locations}\}$$

{Where:

LS = local stress due to integral welded attachment

P = design internal pressure, psi

D_O = outside diameter of pipe, in

t = nominal thickness of pipe, in

M_{DW} = resultant moment due to dead weight, in-lbs

M_{OBE} = resultant moment due to operating basis earthquake, in-lbs

M_{TH} = resultant moment due to thermal expansion, in-lbs

S_h = material allowable stress at temperature, psi

S_A = material allowable stress range, psi

Z = section modulus of pipe, in^3

i = stress intensification factor as given in Figure NC-3673.2(b)-1

B_1 = primary stress index for pressure stress as given in Table NB-3681(a)-1

B_2 = primary stress index for bending stresses as given in Table NB-3681(a)-1

Description of Analyses and Evaluations

Postulated Piping Failures Inside Containment

The current design basis of PBNP includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the reactor coolant system (RCS) primary loop piping, the Pressurizer Surge Line, the Accumulator Injection Line piping including a portion of the RHR return line piping, the RHR return line and the RHR suction line. LBB is addressed in LR Section 2.1.6, Leak-Before-Break, which describes the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis continues to be valid following implementation of the EPU.

Injection paths leading to unbroken reactor coolant loops are protected against damage as a result of reactor coolant pipe rupture. Movement of the injection lines, associated with the rupture of a reactor coolant branch line, is accommodated by line flexibility and by the design of pipe supports such that no damage outside the loop compartment is possible. The movements of the injection lines, associated with the rupture of a reactor coolant loop, remain essentially unchanged for EPU and were demonstrated to be acceptable.

There was no increase in MS or FW pressure for piping inside containment; therefore, the HELB forces in the existing evaluations are bounded for EPU conditions. There were no new pipe break locations postulated in the MS and FW piping inside containment. Therefore, there is no change in pipe rupture loadings inside containment for MS and FW.

Postulated Piping Failures Outside Containment

Affected high energy piping systems were evaluated to address revised EPU operating conditions. The revised pipe rupture postulation criteria were reviewed as well as changes to piping operating temperatures and pressures, and piping system stress levels resulting from EPU were reviewed against pipe break evaluation requirements. The evaluations were based on the licensing basis changes, as described above, and the license design basis for pipe break, jet impingement, pipe whip. The HELB license basis change requires NRC approval prior to implementation of EPU.

For high energy piping systems that currently have a seismic pipe stress analysis, the HELB evaluations determined that all previous arbitrary intermediate break locations can be eliminated. The evaluations resulted in a few locations that exceeded the pipe break stress threshold.

For high energy piping systems that currently do not have a seismic pipe stress analysis, a pipe break must be postulated at the weld to every fitting, valve and welded attachment per MEB 3-1. Rather than determine all of these locations, a pipe break was postulated in every compartment that the applicable piping traversed. In addition, a crack was postulated to occur anywhere along the run of the pipe at the most adverse condition. Appropriate break and crack locations for jet impingement and pipe whip restraint were considered.

EPU did not identify any new breaks, create any new impingement concerns, or create any new whip restraint impacts that need to be analyzed..

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP staff has evaluated the EPU impact on the conclusions reached in the PBNP License Renewal Safety Evaluation Report for pipe break, jet impingement and pipe whip considerations. As stated in Section 2.4 of NUREG-1839 (Reference 1), pipe rupture locations and dynamic effects are within the scope of license renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There were changes associated with the evaluation of pipe break, jet impingement, and pipe whip considerations at EPU conditions. However, no new aging effects requiring management were identified.

Results

The results of the HELB EPU evaluations are as follows.

- Revised criterion for defining pipe break and crack locations and configurations requires NRC approval for EPU
- Criterion dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe whip restraints is unaffected by EPU
- Revised pipe whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe whip dynamic effects have been evaluated and demonstrated to be acceptable for EPU
- The final design of SSC's remain acceptable to protect safety related SSC's from the effects of pipe whip and jet impingement loading for EPU

Therefore, for rupture and crack postulation issues, the PBNP piping and support systems meet their licensing basis. The licensing basis change in methodology for outside containment HELBs described in this LR section requires NRC approval prior to implementation.

2.2.1.3 Conclusions

The change in licensing basis methodology for outside containment HELBs described in this LR Section requires NRC approval prior to implementation.

PBNP has assessed the effects of evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the evaluations have adequately addressed the effects of the proposed EPU on them. PBNP further concludes that the evaluations have demonstrated that safety-related structures, systems, and components important to safety will continue to meet the requirements of PBNP GDC 40 following implementation of the proposed EPU. Therefore, the PBNP finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.1.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2. NRC Generic Letter (GL) 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, June 19, 1987

3. ASME Code Case N–729–1, Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1, March 28, 2006

4. ASME Code Case N-392-1, Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 2 & 3 Piping, dated December 1989

2.2.2 Pressure-Retaining Components and Component Supports

Introduction

In keeping with the format of RS-001, this LR Section is arranged differently than the others. In this section, there is a "Regulatory Evaluation" subsection that generally applies to all of the specific components that are addressed individually in each of the later "Technical Evaluation" subsections. In addition to the generic Regulatory Evaluation contained herein, any amplifications or qualifications that are necessary for individual types of components are provided in the Introduction for each component in their respective subsection.

There is also a generic "Current Licensing Basis (CLB)" subsection that addresses compliance with the generic Regulatory Evaluation criteria. In addition to the generic CLB subsection, when necessary, a component-specific CLB provides further details pertinent to the component, and explains any exception to the generic CLB, in their respective subsection.

Regulatory Evaluation

PBNP has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME Section III, Division 1, and GDC 1, 2, 4, 14, and 15. The PBNP 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. Although analysis of flow induced vibration effects is not included in the plant's current licensing basis, the PBNP review covered the impact of higher EPU flow rates on flow-induced vibration in certain more susceptible components. PBNP's review also included a comparison of the resulting stresses and cumulative fatigue usage factors 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 structures, systems, and components 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 those structures, systems, and components 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 structures, systems, and components 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 reactor coolant pressure boundary be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture
- GDC 15, insofar as it requires that the reactor coolant system be designed with margin sufficient to ensure that the design conditions of the reactor coolant pressure boundary 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 RS-001.

PBNP Current Licensing Basis

As noted in the Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the

FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for pressure retaining components are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System and the Containment System are of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice. The concrete structure of the reactor containment conforms to the applicable portions of ACI-318-63 (Reference 1). Details of the quality assurance programs, test procedures, and inspection acceptance levels are given in FSAR Sections 4.4, Tests and Inspections, 5.1, Containment System Structure, and 5.6, Construction.

The quality control and quality assurance program for PBNP is described in FSAR Section 1.4, Quality Assurance Program. The, Quality Assurance Topical Report (QATR), commits PBNP to compliance with 10 CFR 50.55a, "Codes and Standards."

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

All piping, components and supporting structures of the Reactor Coolant System are designed as seismic Class I equipment. Seismic Design Classification details are given in Appendix A.5.

The Reactor Coolant System is located in the containment building whose design, in addition to being a seismic Class I structure, also considers accidents or other applicable natural phenomena.

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

The mechanical consequences of a pipe rupture are restricted by design such that the functional capability of the engineered safety features is not impaired.

The use of leak-before-break is described in LR Section 2.1.6, Leak Before Break, of this report. Seismic and Dynamic Qualification of Mechanical and Electrical Equipment is described in LR Section 2.2.5, Seismic And Dynamic Qualification of Mechanical and Electrical Equipment. Pipe Rupture Locations and Associated Dynamic Effects is described in LR Section 2.2.1, Pipe Rupture Locations And Associated Dynamic Effects.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

FSAR Section 4.1, Reactor Coolant System, Design Basis, discusses the capability of the reactor coolant pressure boundary.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. The fracture toughness of the materials in the beltline region of the reactor vessel will decrease as a result of fast neutron irradiation induced embrittlement. Fracture toughness will decrease with increasing the reference nil ductility temperature (RT_{NDT}), which increases as a function of several factors, including accumulated fast neutron fluence. This change in material properties is factored into the operating procedures such that the reactor coolant system pressure is limited with respect to RCS temperature during plant heatup, cooldown, and normal operation.

In addition to their GDC compliance as described above, PBNP pressure-retaining components and supports were evaluated for plant license renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 2)

Systems and system components, including materials of construction, operating history, programs used to manage aging effects, and time limited aging analyses are documented in SER Sections 2.3, 3.0, 3.1, 3.2, 3.3, 3.5, and 4.3. The fatigue monitoring program manages the time-limited-aging-analysis (TLAA) for metal fatigue and is discussed in Section 4.3 of the SER.

Pressure-Retaining Components and Component Supports References

1. American Concrete Institute (ACI) 318-63, SP-10 Commentary on ACI 318-63 Building Code, January 01, 1965

2. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.2.2.1 NSSS Piping, Components and Supports

2.2.2.1.1 Regulatory Evaluation

Introduction

The PBNP Unit 1 and Unit 2 nuclear steam supply system (NSSS) piping, which is the reactor coolant system (RCS) piping, consists of two heat transfer piping loops (loops A and B) connected in parallel to the reactor pressure vessel (RPV). Each loop contains a circulating pump called the reactor coolant pump (RCP) and a steam generator. Each RCS loop consists of three legs: the hot leg from the RPV to the steam generator, the cross-over leg from the steam generator to the RCP, and the cold leg from the RCP to the RPV. The system also includes a pressurizer, pressurizer relief tank, connecting piping, and the instrumentation for operational control. The pressurizer is connected to loop B. Auxiliary system piping connections into the RCS piping are provided as necessary. The RCS piping system is supported by the primary equipment supports of the RCS, namely the RPV supports, the steam generator supports, the RCP supports, and the pressurizer supports.

The NSSS piping, components, and supports, as contained in the FSAR Sections 3.1, General Design Criteria, 3.2, Reactor Design, 4.0, Reactor Coolant System, 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 4.4,Testing and Inspections, 5.2, Containment Isolation System, 6.1, Engineered Safety Features, Criteria, 9.1, Component Cooling Water, 15.4.2, Evaluation of Timelimited Aging Analysis, Fatigue, and Appendix A.5, Seismic Design Analysis, were evaluated for EPU. The existing design-basis analyses for reactor coolant loop (RCL) piping, RCL primary equipment supports, and pressurizer surge line including thermal stratification were reviewed for the effects of input parameters that would change with the implementation of EPU.

Specifically, the following analyses were evaluated and, where necessary, reanalyzed with EPU parameters:

- RCL loss-of-coolant accident (LOCA) analysis using Loop LOCA hydraulic forces for the EPU program and the associated Loop LOCA reactor pressure vessel (RPV) motions for the EPU program
- RCL piping stresses
- RCL displacements at auxiliary piping line connections to the centerline of the RCL at branch nozzle connections and impact on the auxiliary piping systems
- Primary equipment nozzle loads
- RCL piping system leak-before-break (Leak Before Break) loads for Leak Before Break evaluation
- Pressurizer surge line piping analysis including the effects of thermal stratification
- RCL primary equipment support loads (Reactor Vessel, Steam Generator, Reactor Coolant Pump, and Pressurizer)

PBNP Current Licensing Basis

The Current Licensing Basis in LR Section 2.2.2, above, applies to NSSS piping, components, and supports, with the following amplification. As discussed in FSAR Section 15.3, Time Limited Aging Analysis Supporting Activities, and the License Renewal SER (NUREG-1839 Reference 5) Section 3.0.3.2.22, a commitment was made to implement an enhanced fatigue monitoring program. The Fatigue Monitoring Program monitors loading cycles due to thermal and pressure transients and cumulative fatigue usage for ASME Code Class 1 and selected Class 2 components analyzed to Class 1 rules for which a cyclic or fatigue design basis exists. Also, from the License Renewal SER, the 40 year design transient set remains valid (bounding) for 60 years of operation at an assumed power level of 1678MWt.

NRC Bulletin 88-11 (Reference 4) requested licensees to take certain actions to monitor thermal stratification in the pressurizer surge line because measurements indicate that top-to-bottom differential temperature in the surge line can reach 250°F to 300°F in certain modes of operation, particularly during heatup and cooldown. Westinghouse performed a plant specific analysis of the PBNP pressurizer surge line to demonstrate compliance with NRC Bulletin 88-11 (Reference 4), and the results are reported in WCAP-13509 (proprietary) (Reference 3) and WCAP-13510 (nonproprietary) (Reference). The results indicate that for PBNP Units 1 and 2, each surge line meets the stress limits and cumulative usage factor requirements. Plant operating strategies as discussed in WCAP-13588, Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients, dated March 1993, have an effect on the frequency and severity of pressurizer flow surges. Work performed by Westinghouse for the Westinghouse Owners Group (WOG) during the past decade has shown that modified plant operational strategies such as those that have been implemented at PBNP can provide an effective means of mitigating pressurizer insurge-outsurge transients.

Analysis of flow induced vibration was considered for susceptible components that would experience a significant flow increase under EPU conditions. NSSS piping and components were evaluated and deemed unaffected by EPU conditions due to their heavy construction and no increase in flow.

2.2.2.1.2 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

The following four basic sets of input parameters were used in the evaluation for the EPU:

- Design parameters for 1806 MWt as shown in Table 1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters,
- NSSS design transients in LR Section 2.2.6, NSSS Design Transients,
- Loop LOCA hydraulic forcing functions forces in LR Section 2.8.5.6.3.5, Technical Evaluation - LOCA Forces.
- Loop LOCA RPV motions in LR Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports.

The acceptance criteria for the PBNP RCL piping system are based upon the USAS B31.1, Code for Pressure Piping (Reference 1) as used in the current design basis. The USAS B31.1 Code does not require a fatigue evaluation to be performed for the RCL piping system. Since there is no NRC requirement to meet code requirements beyond those in the code of record for the RCL piping, a fatigue evaluation of the RCL piping has not been performed.

Unlike for the RCL piping, for the pressurizer surge line there is a requirement for updating to a newer code. The pressurizer surge line was evaluated to the ASME Section III, Subsection NB 1986 Code (Reference 2), *and includes the fatigue evaluation and the effects of thermal* stratification as stipulated in NRC Bulletin 88-11 (Reference 4), Pressurizer Surge Line Thermal Stratification, December 20, 1988. Bulletin 88-11 (Reference 4) states: "...licensees of plants in operation over 10 years (i.e., low power license prior to January 1, 1979) are requested to demonstrate that the pressurizer surge line meets the applicable design codes* and other FSAR and regulatory commitments for the licensed life of the plant, considering the phenomena of thermal stratification and thermal striping in the fatigue and stress evaluations;" where Note * is "Fatigue analysis should be performed in accordance with the latest ASME Section III requirements incorporating high cycle fatigue." As a result of NRC Bulletin 88-11(Reference 4), the analysis code of record for the surge line was required to be updated to incorporate fatigue evaluations.

The acceptance criteria for the pressurizer surge line thermal stratification analysis are per the ASME V Code (Reference 2), and are as specified in the current design basis in WCAP-13509 (Reference 3).

Nuclear Steam Supply System Design Parameters

The design parameters for operation at 1806 MWt (NSSS) power, as identified in Table 1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters, were used in the thermal analysis of the RCL and used in the evaluation for the pressurizer surge line. The RCL was evaluated for two temperature cases – one for the lower-bound temperature case (Cases 1 and 2), and the second for the upper-bound temperature (Cases 3 and 4), as identified in Table 1-1. The above two thermal cases of the RCL were evaluated to envelope the RCL temperatures and the steam generator tube plugging data specified in Table 1-1.

NSSS Design Transients

The impact on design transients due to the changes in full-power operating temperatures for the EPU is addressed in LR Section 2.2.6, NSSS Design Transients. The design criteria for the RCL piping is the USAS B31.1 Code for Pressure Piping Code (Reference 1). Thus as indicated above no fatigue analysis is required for the main RCL. For the pressurizer surge line, the impact of the design transients with respect to the thermal stratification and fatigue analysis is controlled by ΔT between the pressurizer temperature and the hot-leg temperature. The controlling ΔTs for the pressurizer surge line are associated primarily with the plant heatup and cooldown events which are not affected by the EPU program. It has been reviewed and shown that the temperatures and the design transients affected by the EPU have an insignificant effect on the pressurizer surge line analysis, including the effects of thermal stratification. Therefore, the EPU has no adverse impact on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the results in Reference 3 remain valid.

Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RPV Motions

The impact of the EPU Program on the Loop LOCA hydraulic forcing functions (HFFs) is addressed in LR Section 2.8.5.6.3.5, Technical Evaluation - LOCA Forces, and the associated loop-LOCA RPV motions are addressed in LR Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports. By virtue of Leak-Before-Break, breaks are not postulated for the RCL main loop piping, the pressurizer surge line, and the accumulator and residual heat removal (RHR) lines (see LR Section 2.1.6, Leak-Before-Break). Three pipe break LOCA cases and the associated RPV motions were evaluated for the LOCA analyses performed in the current design basis, namely the accumulator line on the cold leg, the pressurizer surge line on the hot leg, and the RHR line on the hot leg. Subsequently, the application of Leak-Before-Break criteria exempted these three large diameter RCS pipe breaks from consideration. For the EPU program, the loop LOCA hydraulic forcing function forces and associated loop LOCA RPV motions from the smaller branch line breaks are used, namely the 3-inch charging line break on the cold leg, and the 6-inch capped nozzle line break on the hot leg.

Description of Analyses and Evaluations

The design parameters that will change due to EPU were reviewed for impact on the existing RCL piping and consequent impact to the auxiliary lines attached to the RCL centerline at the RCL branch nozzle connections.

The current design basis structural analysis of the RCL piping was performed using the WESTDYN program. As presented in WCAP-8252 Revision 1, Documentation of Selected Westinghouse Structural Analysis Computer Codes, the WESTDYN computer code has an NRC SER formally approving the code and method of analysis. The WESTDYN computer program was used for all applicable deadweight, thermal expansion, and Design Basis Earthquake (DBE) cases. The design basis WESTDYN computer analysis models for these loading cases were evaluated as applicable to reflect the EPU conditions.

The EPU structural evaluation of the RCL piping system included assessment and/or analysis as applicable for deadweight, thermal expansion, and DBE loading conditions. New LOCA analyses were performed for the EPU program for the postulated 3-inch charging line break on the cold leg, and the 6-inch capped nozzle line break on the hot leg.

The deadweight analysis for the EPU was evaluated from the current design basis considering the weight of the RCL piping and the primary system water weight.

The thermal analysis performed for the EPU program evaluated the RCL for the lower-bound temperature and the upper-bound temperature. The RCL was analyzed and evaluated for two temperature cases – one for the lower-bound temperature case (Cases 1 and 2), and the second for the upper-bound temperature (Cases 3 and 4), as identified in Table 1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters. The above two thermal cases of the RCL were evaluated to envelope the RCL temperatures and the steam generator tube plugging data specified in Table 1-1.

The seismic analysis methods and the seismic DBE input response spectra for the EPU parameters are the same as used in the current design basis analysis. The seismic DBE analyses performed considered four seismic DBE cases based on various primary equipment support activity as performed in the design basis analysis, and accounted for the range of operating temperatures as defined by the PCWG parameters for the EPU program in Licensing Report Table 1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters.

LOCA and pipe break analyses for EPU conditions are discussed in LR Section 2.2.2.1.2, Input Parameters, Assumptions, and Acceptance Criteria, under the heading above, Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RPV Motions.

NSSS Piping, Components, and Supports Results

Based on the evaluations performed for the EPU program NSSS PCWG design parameters, NSSS design transients, loop LOCA hydraulic forcing functions (HFFs) and associated RPV motions, it is concluded that there is no adverse effect on the RCL current design basis RCL piping deadweight, thermal, and seismic analyses and evaluations, and the results remain acceptable for the EPU Program for these above stated loading conditions; and the new LOCA analyses and evaluations, and results for the EPU program are also acceptable.

The maximum RCL piping stresses for the EPU program and the corresponding code-allowable stress values are presented in Licensing Report Table 2.2.2.1-1, Maximum RCL Piping Stress Summary. The stresses are combined in accordance with the methods used in the design basis and as specified in the code criteria as described in Reference 1. From the results tabulated in the Licensing Report in Table 2.2.2.1-1, it can be seen that the RCL piping stresses are within the allowable limits and meet the acceptance criteria (Reference 1) and are acceptable for the EPU program.

The applicable RCL piping primary equipment support loads for the EPU parameters were provided for evaluation and confirmation of acceptability (see LR Section 2.2.2.3, Reactor Vessel and Supports, Section 2.2.2.5, Steam Generators and Supports, Section 2.2.2.6, Reactor Coolant Pumps and Supports and Section 2.2.2.7, Pressurizer and Supports).

The primary equipment nozzle loads were compared to the allowables as defined in the equipment design specifications. RCP and RPV nozzle loads were compared to loads previously evaluated and qualified for the design basis. The nozzle loads are acceptable and the EPU has no adverse impact on the analysis results.

The applicable RCL piping loads resulting from the range of operating temperatures, as defined by the EPU NSSS PCWG parameters in Table 1-1 of LR Section 1.1, Nuclear Steam Supply System Parameters, were provided for evaluation and confirmation of Leak Before Break (see LR Section 2.1.6, Leak-Before-Break).

The impact of the EPU program parameters on the RCL piping loads and displacements at the intersection of the centerline of the RCL piping and the auxiliary line piping system branch nozzle connections were transmitted for qualification and acceptance of the auxiliary lines for the EPU program.

For the pressurizer surge line, the impact of the design transients with respect to the thermal stratification and fatigue analysis is controlled by ΔT between the pressurizer temperature and the hot-leg temperature and has been evaluated. The controlling ΔTs for the pressurizer surge line are associated primarily with the plant heatup and cooldown events which are not affected by the EPU program.

As discussed in LR Section 2.2.2.1.2, under the heading Input Parameters, Assumptions, and Acceptance Criteria, the current design basis pressurizer surge line analysis results as documented in Reference 3, including the effects of thermal stratification, are applicable for the EPU program and meet the acceptance criteria for the EPU program.

Conclusions

The parameters associated with the EPU program have been evaluated for their effects on the following:

- RCL piping stresses
- RCL piping system Leak Before Break loads at weld locations for Leak Before Break evaluation
- Accumulator line, RHR line, and pressurizer surge line Leak Before Break loads at weld locations for Leak Before Break evaluation
- RCL piping displacements and loads at the junction of the centerline of the RCL piping and the branch nozzle connections of the auxiliary piping systems to the RCL for impact on auxiliary piping systems and for qualification and acceptance of the auxiliary piping systems
- Primary equipment nozzle loads
- Pressurizer surge line piping analysis including the effects of thermal stratification
- Primary equipment support loads (Reactor Vessel, Steam Generator, and Reactor Coolant Pump and Pressurizer)

The evaluation determined that the parameters associated with the EPU have no adverse effect on the analysis of the RCL piping system, including impacts to the primary equipment nozzles. RCL piping stresses meet the required stress criteria as summarized in Table 2.2.2.1-1, Maximum RCL Piping Stress Summary. The primary equipment nozzle loads are all acceptable. RCL piping loads, RHR line, accumulator line, and pressurizer surge line piping loads at the weld locations are transmitted for Leak Before Break evaluation for the EPU Program and are evaluated in LR Section 2.1.6, Leak-Before-Break. The RCL primary equipment support loads are qualified for acceptance to meet the required stress criteria as summarized in the LR Section 2.2.2.3, Reactor Vessel and Supports, Section 2.2.2.5, Steam Generators and Supports, Section 2.2.2.6, Reactor Coolant Pumps and Supports; and Section 2.2.2.7, Pressurizer and Supports.

RCL piping loads and displacements at the connections of the auxiliary line branch nozzles on the auxiliary piping systems that are attached to the RCL (as applicable) have been evaluated for acceptance of the auxiliary line piping systems for the EPU program.

A review has shown that the temperatures and the design transients affected by the EPU have an insignificant effect on the pressurizer surge line design basis analysis, including the effects of thermal stratification. Therefore, the EPU has no adverse impact on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the results as documented in Reference 3 remain valid for the EPU.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Aging evaluations were previously performed for the NSSS Piping, Components, and Supports for license renewal. These aging evaluations, WCAP-14575-A, Aging Management Evaluation for Class I Piping and Associated Pressure Boundary Components, dated December 2000, and WCAP-14422 Revision 2-A, dated December 2000, License Renewal Evaluation: Aging Management Evaluation for Reactor Coolant System Supports, were approved by the NRC in the License Renewal Safety Evaluation Report (SER) for the Point Beach Nuclear Plant (NUREG-1839). Point Beach has evaluated the impact of the EPU on these evaluations and the conclusions reached in the License Renewal Application for the NSSS Piping, Components, and Supports and has determined that the evaluations remain valid for the EPU conditions. In addition to the aging management evaluations, metal fatigue was identified as a TLAA (Time Limited Aging Analyses - Metal Fatigue) in Section 4.3 of the License Renewal Application. Evaluations performed for license renewal were documented in Section 4.3 of the License Renewal Safety Evaluation Report (NUREG-1839, Reference 5) and incorporated into the Current Licensing Basis. In the License Renewal Safety Evaluation Report (SER), Fatigue Monitoring was required for selected RCS locations. The NRC has approved the actions to manage the effects of aging during the period of extended operation on the functionality of the System Components subject to an Aging Management Review.

PBNP has evaluated the impact of the EPU on the fatigue evaluations performed in support of license renewal and has demonstrated that the 40-year design transient set remains valid (bounding) for a 60 year operating term. Further, the fatigue analyses performed to support license renewal bounds and remains valid for the EPU conditions, and since the 40-year design transient set is valid (bounding) for 60-years of operation, the license renewal fatigue analysis bounds and remains valid for the EPU conditions for 60 years of operation.

Finally, the environmental effects of fatigue were evaluated for the reactor coolant system components based on the updated fatigue usage factors determined from the EPU evaluations. The cumulative usage factors for the pressurizer surge line, reactor coolant piping charging system nozzle, and reactor coolant piping safety injection nozzle are still below the ASME code limit of 1.0

EPU conditions, and the analyses and evaluations performed in support of the EPU, do not impact the aging management reviews, aging management programs, and TLAAs associated with the NSSS Piping, Components, and Supports for the PBNP License Renewal.

Conclusion

Based on the preceding evaluations, PBNP finds the NSSS piping and Supports acceptable for operation at EPU conditions.

References

1. USAS B31.1, Code For Pressure Piping (Note: as per Table 4.1-9 of the FSAR 2007, the version of the Code which was in effect at the time the original component was ordered is applicable)

2. American Society of Mechanical Engineers (ASME) Code, Section III, Subsection NB, 1986 Edition

3. WCAP-13509, Structural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge Lines, Considering The Effects of Thermal Stratification, October 1992

4. NRC Bulletin (BL) 88-11, Pressurizer Surge Line Thermal Stratification, December 20, 1988

5. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

6. WCAP-13510, Strucural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge LInes, Considering The Effects of Thermal Stratification, October 1992

7. WCAP-13588, Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients, dated March 1988

8. WCAP-8252, Documentation of Selected Westinghouse Structural Analysis Computer Codes, dated May 1977

9. WCAP-14575, Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, dated December 2000

10. WCAP-14422, Licensing Renewal Evaluation: Aging Management for Reactor Coolant System Supports, dated December 2000

Table 2.2.2.1-1
Maximum RCL Piping Stress Summary

ANSI B31.1 Code Equation Stress	RCL Piping	Actual Piping Stress For Both Pre-EPU And EPU Conditions ** (ksi)	ANSI B31.1 Code Allowable Stress (ksi)
Equation 11 Pressure + Deadweight	Hot Leg	[ ] b,c	15.9
	Crossover Leg	[ ] b,c	15.9
	Cold Leg	[ ] b,c	15.9
Equation 12 Pressure + Deadweight + DBE	Hot Leg	[ ] b,c	19.08
	Crossover Leg	[ ] b,c	19.08
	Cold Leg	[ ] b,c	19.08
Faulted Pressure + Deadweight + DBE + LOCA	Hot Leg	[ ] b,c	19.08
	Crossover Leg	[ ] b,c	19.08
	Cold Leg	[ ] b,c	19.08
Thermal	Hot Leg	[ ] b,c	23.85
	Crossover Leg	[ ] b,c	23.85
	Cold Leg	[ ] b,c	23.85
** Piping Stresses applicable for Both Pre-EPU and EPU Conditions.			

2.2.2.2 Balance of Plant Piping, Components, and Supports

2.2.2.2.1 Introduction

This section of the Licensing Report covers piping and supports that are not included in Section 2.2.2.1, NSSS Piping, Components and Supports. Section 2.2.2.1 covers Seismic Class 1 reactor coolant loop piping and supports up to the class break at the containment isolation boundary. This section covers Seismic Non-Class 1 and Non-Seismic piping and supports (hereafter referred to as BOP piping and supports), whether inside or outside containment.

PBNP Current Licensing Basis

The generic Current Licensing Basis in Section 2.2.2 applies to the BOP piping, components and supports.

Additional Seismic Non-Class 1 RCS Components System details are provided in Appendix A.5, Seismic Design Analysis, of the FSAR.

2.2.2.2.2 Technical Evaluation

Introduction

BOP piping and support systems were evaluated to assess the impact of operating temperature, pressure and flow rate changes that will result due the implementation of EPU. The BOP piping affected by EPU was evaluated to the USAS B31.1 Power Piping Code, 1967 Edition (Reference 1) which is the original code of record for most PBNP BOP piping systems.

The PBNP BOP piping and support systems that were evaluated for EPU conditions included the following systems.

- Main Steam
- Feedwater
- Condensate
- Heater Vent and Drains
- Extraction Steam
- Circulating Water
- Component Cooling Water
- Auxiliary Feedwater
- Spent Fuel Pool Cooling
- Service Water
- Steam Generator Blowdown
- Safety Injection

- Containment Spray
- Chemical and Volume Control
- Residual Heat Removal
- Condenser Air Removal and Vacuum Priming
- Gland Steam and Drains
- Reheat Steam
- Turbine Crossover and Crossunder Piping

Description of Analyses and Evaluations

System operation at EPU conditions generally results in increased pipe stress levels and pipe support and equipment loads due to slightly higher operating temperatures, pressures and flow rates.

Pre-uprate and EPU operating data (operating temperature, pressure and flow rate) were obtained from heat balance diagrams, calculations, and/or other reference documents.

Thermal change factors were determined, as required, to compare and evaluate changes in thermal operating conditions. The thermal "change factors" were based on the following ratio:

- The thermal "change factor" equals the ratio of the power uprate to pre-uprate operating temperature. That is, thermal change factor is $(T_{uprate}\text{-}70°F)/(T_{pre\text{-}uprate}\text{-}70°F)$.

Based on the magnitude of the calculated thermal change factors, the following engineering activities were performed and/or conclusions reached.

For thermal change factors less than or equal to 1.00 (that is, the pre-uprate condition envelopes or equals the EPU condition), the piping system was concluded to be acceptable for EPU conditions.

For thermal change factors greater than 1.00, an additional evaluation was performed to address the specific increase in temperature, in order to determine piping system acceptability.

Operating pressure increases due to EPU were very small and mostly affected systems related to the main power cycle (main steam, condensate, feedwater, extraction steam, heater drains). Since the pipe stress evaluations for piping systems at PBNP have used the system design pressure in accordance with USAS B31.1 (Reference 1), the small increases in operating pressures were acceptable, as long the EPU operating pressure remains within the current design pressure of the system. If the EPU operating pressure exceeded the design pressure, the impact on the piping system was evaluated.

Flow rate increases due to EPU occur mainly in systems related to the main power cycle. The two piping systems of most concern with respect to flow rate increases are main steam and feedwater systems. Flow rate increases and their impact on potential flow induced fluid transient loads were evaluated for the main steam and feedwater piping systems. The evaluation of the main steam system addressed the system flow rate increase and its impact on fluid transient loads (i.e., steam hammer loads) resulting from a turbine stop valve closure event. The evaluation of the feedwater system addressed the flow rate increase and its impact on fluid transient loads (i.e., water hammer loads) resulting from feedwater regulating and isolation valve closure/feedwater pump trip events.

The BOP piping and support systems affected by EPU were evaluated to the USAS B31.1 Power Piping Code, 1967 Edition (Reference 1), which is the original code of record for most PBNP BOP piping systems.

There were no changes to seismic inputs (amplified response spectra) or loads resulting from EPU. The existing seismic design basis for all piping and supports remains valid and unaffected by EPU. Hence, BOP piping and support seismic loadings will continue to meet the PBNP current licensing basis with respect to the requirements of PBNP GDC 2.

The computer programs listed below were used in performing the EPU piping and pipe support evaluations. These computer programs are not currently described in the FSAR and do not conflict with any computer programs used and discussed in the FSAR. These computer programs were used in performing the EPU piping and support evaluations and have been evaluated by PBNP as being acceptable for the analysis of the affected piping. These computer programs are used to calculate stresses and loads using appropriate equations from the USAS B31.1 criteria. Using an approved Quality Assurance program these computer programs have been verified and validated and shown to be accurate. Thus the programs are appropriate for use in QA Category I Nuclear Safety Related applications. Refer to LR Appendix B for list of computer codes used for EPU that are not currently described in the FSAR.

Computer Program	Program Description
STEHAM-PC	The STEHAM-PC program was used to determine forcing functions for the main steam turbine stop valve closure event. This program determines forcing functions in steam-filled piping systems due to valve opening and closing conditions
WATHAM-PC	The WATHAM-PC program was used to determine forcing functions for the feedwater regulatory valve and isolation closure and feedwater pump trip events. This program determines forcing functions in water-filled piping systems due to pump start/stop/trip, check valve closure and valve opening and closing events
NUPIPE-SWPC	The NUPIPE-SWPC program was used to perform detailed pipe stress analysis. This program is designed to perform analyses in accordance with the ASME Boiler and Pressure Vessel Code, Section III Nuclear Power Plant Components and the ANSI/ASME B31.1 Power Piping Code
PC-PREPS	The PC-PREPS program was used to perform detailed pipe support evaluations. This program performs a complete structural analysis, performing an AISC code check, weld qualification and baseplate/anchor bolt qualifications
ANSYS	The ANSYS program was used to perform detailed integral welded attachment evaluations.

For BOP piping and support systems that required detailed analyses to reconcile EPU operating parameters, a summary of revised stress levels corresponding to EPU conditions is provided in Table 2.2.2.2-1. The results presented include existing stress levels (i.e., pre-uprate), revised pipe stress levels for EPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile EPU conditions. The design margin provided is based on the ratio of the calculated stress divided by the allowable stress.

Other evaluations of issues that potentially impact BOP piping and supports are addressed in the following LR Sections.

- Protection against dynamic effects of pipe whip and discharging fluids is discussed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and in LR Section 2.5.1.3, Pipe Failures.
- Protection against internally generated missiles and turbine missiles is discussed in LR Section 2.5.1.2.1, Internally Generated Missiles and LR Section 2.5.1.2.2, Turbine Generator, respectively.

Design of the Reactor Coolant System and related components is discussed in LR Section 2.2.2.1, NSSS Piping, Components and Supports.

Results

The results of the piping evaluations concluded that revised pipe stresses in BOP systems remain within allowable limits for EPU conditions. Table 2.2.2.2-1, Stress Summary at EPU Conditions, provides a summary of existing stress levels (i.e., pre-uprate), revised pipe stress levels for EPU conditions, and the resulting design margin for each piping analysis that required detailed evaluation to reconcile EPU conditions. Piping systems not specifically listed in Table 2.2.2.2-1 did not require detailed evaluation (i.e., no significant operating parameter increases due to EPU) to reconcile EPU conditions or involve piping and support systems which will experience plant modifications. The piping evaluations also concluded that stresses in portions of the extraction steam system with EPU operating pressures that slightly exceed the existing design pressure (i.e, inlet of feedwater heaters 3, 4 and 5) will remain within allowable limits. The affected piping and components will be rerated to be consistent with the new design parameters. The stress results reported in Table 2.2.2.2-1 have incorporated thermal expansion and fluid transient increases, as applicable, that were reconciled as part of the EPU evaluations.

The piping stress evaluations performed conclude that piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from EPU conditions, although pipe support modifications are required to accommodate the revised support loads due to EPU. The piping evaluations concluded that the main steam piping system can withstand the steam hammer loads associated with EPU conditions (resulting from a turbine stop valve closure event) and the feedwater piping system can withstand the water hammer loads associated with EPU conditions (resulting from a feedwater regulatory valve and isolation closure/pump trip event). The results of the pipe support evaluations for systems impacted by EPU concluded that all supports remain acceptable, except for certain main steam and feedwater system pipe supports that require modification to accommodate the revised loads related to EPU conditions. Additionally, new pipe supports were added to the feedwater piping system. The main steam and feedwater pipe support modifications are required to mitigate the larger flow induced fluid transient loads that resulted due to EPU conditions. The main steam and feedwater support modifications generally involve upgrading/strengthening existing components, such as, increasing existing welds, installing higher capacity struts, and adding steel frame members. These pipe support modifications will be installed before the implementation of the EPU. Refer to LR Section 1.0, Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report, for a summary of plant modifications.

For piping systems which require plant modifications (e.g., piping systems impacted by the replacement of feedwater heaters) to address EPU conditions, the piping and support evaluations will be performed as part of the overall design change package associated with the specific plant modification.

As discussed in LR Section 2.5.4.5, Auxiliary Feedwater, the system is being redesigned, and two higher capacity motor-driven AFW pumps will be installed to meet higher EPU flow requirements. Affected piping configuration changes and associated pipe stress and support evaluations will be performed as part of the modification process for the AFW system.

The results of the turbine crossover and crossunder piping evaluations concluded that these piping systems remain within acceptable limits for EPU conditions, including consideration of the increase in design pressure for the crossunder piping and for the crossover piping discussed in LR Section 2.5.5.1, Main Steam.

The results of the equipment nozzle and containment penetration evaluations concluded that these components remain within acceptable limits for EPU conditions.

In summary, the BOP piping and support systems will continue to meet the PBNP current licensing basis.

Additionally, the implementation of EPU will result in higher flow rates for several piping systems. Piping systems experiencing these higher flow rates require review for potential flow induced vibration issues. The piping vibration reviews are included as part of the start-up testing program related to the overall implementation of EPU. Refer to LR Section 2.12, Power Ascension and Testing Plan, for further discussions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

With respect to the pipe support modifications for the main steam and feedwater piping systems, these modifications will not impact the License Renewal system evaluation boundaries. The required pipe support modifications do not add any new or previously unevaluated materials to the BOP piping and support systems. No new aging effects requiring management are identified.

Piping system internal and external environments remain within the parameters previously evaluated. The Time-Limited Aging Analyses evaluations remain bounding.

2.2.2.2.3 Conclusions

The EPU will result in pipe support modifications for the main steam and feedwater piping systems.

PBNP has assessed the effects of the proposed EPU on the structural integrity of pressure-retaining components and their supports. PBNP concludes that the BOP piping assessments adequately addressed the effects of the proposed EPU on BOP piping components and their supports. PBNP further concludes that the evaluations have demonstrated that pressure-retaining components and their supports will continue to meet the requirements and PBNP GDC 1, 2, and 40 as applicable following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the structural integrity of the BOP piping pressure-retaining components and their supports.

2.2.2.2.4 References

1 USAS B31.1, Code For Pressure Piping (Note: as per Table 4.1-9 of the FSAR 2007, the version of the Code which was in effect at the time the original component was ordered is applicable)

Table 2.2.2.2-1 Stress Summary at EPU Conditions

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Notes 1 & 3)
Unit 1 Main Steam Inside Containment Loop A	Equation 9B (Occasional)	17,849	19,107	21,000	0.91
	Equation 9C (Occasional)	19,107	21,405	31,500	0.68
Unit 1 Main Steam Inside Containment Loop B	Equation 9B (Occasional)	12,371	12,676	21,000	0.60
	Equation 9C (Occasional)	13,506	13,546	31,500	0.43
Unit 1 Main Steam Outside Containment	Equation 9B (Occasional)	19,107	20,930	21,000	0.997
	Equation 9C (Occasional)	23,608	25,081	31,500	0.80
Unit 2 Main Steam Inside Containment Loop A	Equation 9B (Occasional)	19,297	20,706	21,000	0.99
	Equation 9C (Occasional)	29,046	29,984	31,500	0.95
Unit 2 Main Steam Inside Containment Loop B	Equation 9B (Occasional)	12,517	12,614	21,000	0.60
	Equation 9C (Occasional)	14,186	14,241	31,500	0.45
Unit 2 Main Steam Outside Containment	Equation 9B (Occasional)	19,107	20,827	21,000	0.99
	Equation 9C (Occasional)	26,241	27,206	31,500	0.86
Unit 1 Feedwater Inside Containment Loop A	Equation 9B (Occasional)	14,780	15,119	18,000	0.84
	Equation 9C (Occasional)	20,643	20,812	27,000	0.77
	Equation 11 (Sustained + Thermal)	17,692	18,277	37,500	0.49

Table 2.2.2.2-1 Stress Summary at EPU Conditions

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Notes 1 & 3)
Unit 1 Feedwater Inside Containment Loop B	Equation 9B (Occasional)	11,163	11,293	18,000	0.63
	Equation 9C (Occasional)	12,630	12,706	27,000	0.47
	Equation 11 (Sustained + Thermal)	22,220	23,009	37,500	0.61
Unit 1 Feedwater Outside Containment (See Note 4)	Equation 9B (Occasional)	17,098	17,153	18,000	0.95
	Equation 9C (Occasional)	26,556	26,584	27,000	0.98
	Equation 11 (Sustained + Thermal)	17,858	20,679	37,500	0.55
Unit 2 Feedwater Inside Containment Loop A	Equation 9B (Occasional)	14,027	14,588	18,000	0.81
	Equation 9C (Occasional)	16,310	16,691	27,000	0.62
	Equation 11 (Sustained + Thermal)	17,351	17,708	37,500	0.47
Unit 2 Feedwater Inside Containment Loop B	Equation 9B (Occasional)	12,324	12,625	18,000	0.70
	Equation 9C (Occasional)	15,960	16,133	27,000	0.60
	Equation 11 (Sustained + Thermal)	14,508	14,785	37,500	0.39
Unit 2 Feedwater Outside Containment (See Note 4)	Equation 9B (Occasional)	17,528	17,614	18,000	0.98
	Equation 9C (Occasional)	26,444	26,488	27,000	0.98
	Equation 11 (Sustained + Thermal)	20,960	21,516	37,500	0.57

Table 2.2.2.2-1 Stress Summary at EPU Conditions

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Notes 1 & 3)
Unit 1 Condensate Inlet and Outlet to FWH-20A & 20B	Equation 10 (Thermal)	4070	4335	22,500	0.19
Unit 1 Extraction Steam Inlet to FWH-20A & 20B	Equation 11 (Sustained + Thermal)	32,700	34,546	42,350	0.82
Unit 1 Heater Drains Outlet from FWH-20A & 20B to HD Tank	Equation 10 (Thermal)	6526	6827	22,500	0.30
Unit 1 Heater Drains Outlet from FWH-21A to FWH-20A	Equation 10 (Thermal)	7497	7843	22,500	0.35
Unit 1 FWH-20A & 20B Vent Piping from Drain Tank	Equation 10 (Thermal)	4509	4718	22,500	0.21
Unit 1 Extraction Steam Inlet to FWH-21A & 21B	Equation 10 (Thermal)	7842	8417	27,110	0.31
Unit 1 FWH-20A&B and FWH-21A&B RV Discharge	Equation 10 (Thermal)	15,900	16,751	22,500	0.74
Unit 1 Heater Drains Outlet from FWH-21B to FWH-20B	Equation 10 (Thermal)	8973	9387	22,500	0.42
Unit 1 Heater Drains Outlet from FWH-21A & 21B	Equation 10 (Thermal)	17,682	20,997	22,500	0.93
Unit 1 MSR to Heater Drain Tank	Equation 10 (Thermal)	11,799	12,256	22,500	0.54
Unit 1 Loop A Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	7990	10,387	22,500	0.46
Unit 1 Loop B Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6600	8580	22,500	0.38
Unit 2 Loop A Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6540	8502	22,500	0.38

Table 2.2.2.2-1 Stress Summary at EPU Conditions

Piping Analysis Description	Loading Condition (Note 2)	Existing Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Design Margin (Notes 1 & 3)
Unit 2 Loop B Main Steam to Inlet of AFW Pump Turbine	Equation 10 (Thermal)	6510	8463	22,500	0.38
Units 1 & 2 MS Inlet Piping to MSR A, B, C & D	Equation 10 (Thermal)	2657	2904	22,500	0.13

NOTES:

1. The Design Margin is based on the ratio of EPU stress divided by the Allowable stress.
2. The Equation Numbers shown correspond to ASME Section III, NC/ND-3650 Equation Numbers.
3. With respect to piping analyses containing design margins greater than 0.90 for EPU conditions, it should be noted that the existing design margins (for the same loading condition) for all these piping analyses, with the single exception of U1 Main Steam Piping Inside Containment Loop A, are currently greater than 0.90. For example, the U2 Main Steam Piping Inside Containment Loop A, Equation 9C, has a reported design margin of 0.95 based on the ratio of 29,984 (EPU stress) divided by 31,500 (allowable stress). The existing design margin for this piping is 0.92 based on the ratio of 29,046 (current stress) divided by 31,500 (allowable stress). Hence, for this piping system, the actual stress increase resulting from EPU is not that significant. Additionally, all stress levels resulting in design margins less than or equal to 1.0 are acceptable limits in accordance with USAS B31.1 code of record. The allowable stress levels for the USAS B31.1 code are stress levels that are well below material ultimate stress limits.
4. Stress levels shown are based on the current plant configuration at EPU conditions. Potential piping modifications due to planned feedwater pump replacements may result in a change in the EPU stress levels. The piping evaluations related to the pump replacements will be performed as part of a plant design change package, and any changes to EPU stress levels will remain within applicable allowable stress limits.

2.2.2.3 Reactor Vessel and Supports

2.2.2.3.1 Regulatory Evaluation

PBNP Current Licensing Basis

The generic Current Licensing Basis in LR Section 2.2.2, Pressure Retaining Components and Component Support, above, applies to nuclear steam supply system (NSSS) piping, components, and supports, with the following amplifications. The PBNP reactor vessel were designed and fabricated in accordance with Westinghouse specifications and applicable requirements of the 1965 Edition of Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code for the Unit 1 reactor vessel and the 1968 Edition of the ASME Code with addenda through Winter 1968 for the Unit 2 reactor vessel. The reactor vessel is described in PBNP Updated Final Safety Analysis Report (FSAR), Chapter 3, Reactor, and Chapter 4, Reactor Coolant System, the governing code requirements are listed in FSAR Table 4.1-9, Reactor Coolant System, Code Requirements.

Replacement reactor vessel closure heads (RVCHs), with replacement control rod drive mechanisms (CRDMs), instrument port head adaptors (IPHAs), core exit thermocouple nozzle assemblies (CETNAs) and associated components were installed at PBNP during the Unit 1 and Unit 2 2005 refueling outages. The replacement RVCH, replacement CRDMs, IPHAs, CETNAs and associated components were designed, fabricated, inspected and tested in accordance with the requirements of the applicable Westinghouse Design Specifications and the ASME B&PV Code for Class 1 Vessels, 1998 Edition through 2000 Addenda. An ASME Section XI reconciliation has been performed to evaluate the differences between the original codes of construction and the later edition of the ASME Code used for fabrication and analysis of their replacements. The codes of construction for the original PBNP RVCHs are: ASME Section III, 1965 Edition for Unit 1 and 1968 Edition through Winter 1968 Addenda for Unit 2. The codes of construction for the original CRDMs are: ASME Section III, 1965 Edition through Summer 1966 Addenda for Unit 1 and 1965 Edition through Summer 1967 Addenda for Unit 2.

In addition to the basis described in the regulatory evaluation section above, the reactor vessel and vessel supports were evaluated for plant license renewal. The evaluations are documented in:

- Safety Evaluation Report (SER) Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 7)

The results of the NRC review of the vessel supports are documented in Section 3.5 of the SER. A Time Limited Aging Analysis (TLAA) related to the reactor vessel is documented in Section 4 of the SER.

2.2.2.3.2 Technical Evaluation

Introduction

The PBNP reactor pressure vessels (RPVs), as the principal component of the reactor coolant system (RCS), contain the heat-generating core and associated supports, controls and instrumentation, and coolant circulating channels. Primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core.

The Unit 1 RPV consists of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The Unit 1 RPV shell is fabricated from longitudinally welded plate rings joined by circumferential welds. The Unit 2 RPV consists of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The Unit 2 RPV shell is fabricated from integral ring forgings joined by circumferential welds. The RPVs contain the core, core support structures, rod control clusters, thermal shield, and other parts directly associated with the core. Inlet and outlet nozzles are located at an elevation between the head flange and the core. The body of the RPVs is low-alloy carbon steel, and the inside surfaces in contact with coolant are clad with austenitic stainless steel to minimize corrosion. The RPVs are supported by steel pads integral with the coolant nozzles in addition to two external brackets welded to each reactor vessel. The pads and brackets rest on steel support shoes that are pinned to a large structural steel support frame.

The stress and fatigue effects of the revised operating parameters and RCS transients associated with the EPU have been evaluated. The maximum primary-plus-secondary stress intensity ranges, the maximum cumulative fatigue usage factors, and the vessel support loads resulting from the revised operating parameters and EPU transients have also been evaluated. For items related to RPV material surveillance and limits during operation, refer to License Report (LR) Section 2.1.1, Reactor Vessel Material Surveillance Program, LR Section 2.1.2, Pressure-Temperature Limits and Upper-Shelf Energy and LR Section 2.1.3, Pressurized Thermal Shock.

Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

Presented in the structural report are the analyses and evaluations necessary per Section III of the ASME B&PV Code to substantiate the structural adequacy of the Units 1 and 2 RPVs for operation under EPU conditions.

The analyses and evaluations performed reconcile the PBNP EPU revised operating temperatures, RCS transients, and revised seismic and loss of coolant accident (LOCA) reactor vessel/reactor internals (RV/RI) interface loads with the original reactor vessel stress reports (References 1 and 2), the replacement steam generator (RSG) report (Reference 3) and the replacement RVCH reports (References 4 and 5). Table 2.2.2.3-1, PBNP Baseline Stress Reports, lists the Unit 1 and Unit 2 baseline stress reports.

Assumptions

The following assumptions were made in performing the evaluations of the reactor vessel components:

- PBNP Unit 2 was selected as the basis for the evaluations based on the discussion in Reference 3 which compared the corresponding geometry and materials of the two PBNP units. The only difference in the vessel geometries of any consequence was at the primary nozzle safe ends where the Unit 2 safe end outer diameters are 1/2 inch larger than the Unit 1 safe end outer diameters. The vessel materials were determined to be essentially the same for both reactor vessels. Therefore, the results of the evaluations (with a few exceptions to be noted) were determined to be applicable to both reactor vessels.

- The thermal stresses due to rapid transients can be calculated by using the methods outlined in Document PB-151987, Tentative Structural Design Basis for Reactor Pressure Vessels, Section A.3.5, since Section III of the 1965 and 1968 ASME Codes did not have a satisfactory analytical method for determining thermal stresses due to rapid transients. The stress formulas and curves from PB-151987 were the best available analytical data for determining those stresses and were eventually adopted by the ASME Code.
- The changes in pressure during the design transients can be determined by scaling the known transient pressure stresses proportional to the pressure changes. The relationship between pressure and stress due to pressure is linear.
- All regions of the reactor vessel except the upper head and the outlet nozzles operate at T_{cold} temperatures. The upper head and outlet nozzles operate at T_{hot} temperatures.

Acceptance Criteria

The acceptance criteria for the evaluation are derived from the governing ASME B&PV Code for each unit. For Unit 1 RPV components except for the replacement RVCH, the governing ASME Section III, Division 1 Code is the 1965 Edition. For Unit 2 RPV components except for the replacement RVCH, the governing ASME Section III, Division 1 Code is the 1968 Edition up to the Winter 1968 Addenda. For both units, the replacement RVCH and associated penetrations are governed by the 1998 Edition through 2000 Addenda of the ASME B&PV Code, Section III, Division 1. Revised maximum stress intensity ranges and cumulative fatigue usage factors were calculated and compared to the following acceptance criteria:

- The maximum range of primary-plus-secondary stress intensity resulting from mechanical and thermal loads shall not exceed $3S_m$ at operating temperature per paragraph N-414.4 of the 1965 and 1968 Editions (and aforementioned Addenda) of the ASME Codes, Section III, Division 1. The applicable section is NB-3222.2 in the 1998 Edition through 2000 Addenda of the ASME Code, Section III, Division 1.
- The maximum cumulative fatigue usage factor resulting from the peak stress intensities due to the normal and upset condition design transient mechanical and thermal loads cannot exceed 1.0 in accordance with the procedure outlined in Paragraph N-415.2 of the ASME Code, Section III, Division 1, 1965 and 1968 Editions (and aforementioned Addenda) and, in Paragraph NB-3222.4 of the ASME Code, Section III, Division 1, 1998 Edition through 2000 Addenda.

Description of Analyses and Evaluations

The revised RCS design transients (LR Section 2.2.6, NSSS Design Transients) for the PBNP EPU program were reviewed and compared to the original NSSS design transients and those from the RSG/uprating, license extension and replacement RVCH programs. This transient review determined which EPU transients were more severe than their baseline counterparts by comparing transient temperature (T_{hot} and T_{cold}) rates, magnitudes and durations as well as the pressure variation magnitudes. Based upon this review, the revised transients that must be considered in the EPU stress and fatigue evaluations were determined. Table 2.2.2.3-2 lists the EPU transients that required reconciliation with the existing RPV component analyses.

The stress intensities from the transients listed in Table 2.2.2.3-2 were examined to determine their effect on the maximum ranges of stress intensity for all the regions of the RPV. The changes in the thermal and pressure stresses, due to adverse changes in temperature and/or pressure variations from the baseline transients, were evaluated using standard engineering approaches. The incremental thermal and pressure stress changes were then factored into stress intensities reported in the baseline stress report(s) and the effects of the changes on the maximum ranges of stress intensity were observed.

The peak stress intensity ranges for the fatigue evaluation were also adjusted to account for the incremental thermal and pressure stress changes caused by adverse changes from the baseline transients. The peak stress intensities were conservatively multiplied by the appropriate scaling factor, where necessary, before determining a new peak stress intensity range and finally an alternating stress intensity. The allowable number of cycles of alternating stress intensity was found from the applicable fatigue curve in either the ASME Code, Section III, Division 1, 1968 Edition through Winter 1968 Addenda, or the 1998 Edition through 2000 Addenda, and the cumulative fatigue usage factors were revised accordingly. The 1968 Edition through Winter 1968 Addenda ASME Code, Section III, Division 1 fatigue curves were more conservative than those in the 1965 Edition meaning that the allowable number of cycles calculated for Unit 2 components were conservative for the corresponding Unit 1 components.

Where applicable, the maximum and minimum stress intensity ranges and cumulative fatigue usage factors were revised to reflect the adverse changes to the baseline transients. In other cases, the baseline stress analysis in the baseline stress report(s) remained conservative with regard to the design transients and new calculations were not necessary. For those cases, the maximum stress intensity ranges and cumulative fatigue usage factors reported in the baseline reactor vessel stress report(s) were not changed.

Final seismic and LOCA RV/RI interface loads for the PBNP EPU program were provided for comparison with a set of conservative RV/RI interface loads previously evaluated at the reactor vessel main closure, outlet nozzles and core support pads. The comparison to the allowable loadings was performed to determine if the new EPU RV/RI interface loads were bounded by the allowable loadings. The need for additional stress and fatigue analyses to resolve any loads that exceeded the allowable loads was determined based upon the results of this comparison.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the reactor vessel and supports. Table 3.1-1 of NUREG-1839 (Reference 7) identifies the aging degradation effects considered for both the vessel and its supports, and presents the applicable Aging Management Program or TLAA performed to effectively manage each item of concern.

This LR section addresses the maximum stress intensity ranges and cumulative fatigue damage for all reactor vessel components considering the impact of EPU conditions and evaluates those ranges and fatigue damage against the ASME code limits. This section also addresses the vessel support loads considering the impact of EPU conditions.

Additional vessel-related TLAAs and aging effects identified in Table 3.1-1 of the License Renewal SER are addressed in other LR sections or in various WCAP reports as follows:

- The loss of fracture toughness due to neutron irradiation embrittlement is addressed in LR Section 2.1.1, Reactor Vessel Material Surveillance Program.
- Stress corrosion cracking (SCC) of RV components is addressed in LR Section 2.1.5, Reactor Coolant Pressure Boundary Materials.
- Under clad cracking is addressed in WCAP-15338, A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants, March 2000 Reference 9).
- Aging management for reactor coolant system supports is addressed in WCAP-14422, Rev. 2-A, License Renewal Evaluation: Aging Management for Reactor Coolant System Supports, July 1995 (Reference 10).

PBNP has evaluated the impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the reactor vessel and vessel supports. The aging evaluations approved by the NRC in NUREG-1839 (Reference 5) for the reactor vessel and supports remain valid for EPU conditions.

In addition, the evaluations (summarized in this section) of maximum stress intensity ranges and cumulative fatigue usage factors for the components of the reactor vessel, considering EPU conditions, show that the reactor vessel components continue to meet the ASME acceptable limits. The original 40 year design transient set has been shown to be bounding for 60 years of operation with the exception of the following plant pressure tests: primary side pressure test, primary-to-secondary leak test and secondary-to-primary leak test. However, the number of design cycles for each of these tests has been increased accordingly to account for 60 years of operation. The increased number of design cycles has already been accounted for in the component fatigue evaluations in Reference 3. Since the number of design cycles for the EPU has not changed from the modified 40 year transient set, the fatigue evaluations of the reactor vessel components are valid for 60 years of operation.

For the reactor vessel components determined to be potentially impacted by environmental fatigue, the environmental effects on fatigue were evaluated based on the updated fatigue usage factors determined from the EPU evaluations. The cumulative fatigue usage factors for the inlet nozzle, outlet nozzle, and bottom-head-to-shell juncture, with environmentally-assisted fatigue factors applied, are still below the ASME code limit of 1.0.

Reactor Vessel and Vessel Supports Results

Summary of Results

Based upon the reactor vessel evaluations outlined in this report, all of the maximum ranges of primary-plus-secondary stress intensity and maximum cumulative fatigue usage factors (see Table 2.2.2.3-3, Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factors) for the following PBNP Units 1 and 2 replacement RVCH components continue to satisfy the applicable limits of ASME Code, Section III, Division 1, 1998 Edition through 2000 Addenda:

- Closure head and flange
- CRDM head adapters including bimetallic weld
- Vent nozzles
- IPHA including the CETNA
- Lifting lugs

In addition, all of the maximum ranges of primary-plus-secondary stress intensity and maximum cumulative fatigue usage factors for the balance of the Units 1 and 2 RPV components listed below continue to satisfy the following applicable limits:

Unit 1 – ASME Code Section III, Division 1, 1965 Edition,

Unit 2 – ASME Code, Section III, Division 1, 1968 Edition through Winter 1968 Addenda.

- Vessel flange
- Closure Studs
- Outlet nozzles and support pads
- Inlet nozzles and support pads
- Safety injection nozzles
- Vessel wall transition
- Bottom head-to-shell juncture
- Core support pads
- External support brackets

The RV/RI interface loads are also below the allowable loads. (See Table 2.2.2.3-4, Reactor Vessel/Reactor Internals Interface Loads (lbs))

The environmental effects on fatigue were evaluated and found to be below the ASME Code limit under EPU conditions.

The revised RPV supports loads for the EPU conditions are shown in Table 2.2.2.3-6, Revised Design Basis EPU RPV Support Loads (per Support). A structural analysis and evaluation of the support shoe and structure were performed with the revised loads. The allowable load limits were established in accordance with the "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," AISC, 1969 Edition (Reference 10), the original design code of record. The revised RPV supports loads and load combinations were found to be less than the appropriate allowable load limits, see Table 2.2.2.3-5, Summary of RPV Support Component Stress Interaction Ratios. It has been shown that the RPV supports maintain adequate design margins for support loads resulting from EPU conditions.

2.2.2.3.3 Conclusions

PBNP has reviewed the evaluations related to the structural integrity of the reactor vessel and vessel supports and concludes that the evaluations have adequately addressed the effects of the proposed EPU on the reactor vessel and vessel supports. PBNP further concludes that the evaluations have demonstrated that the reactor vessel and vessel supports continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1, 2, 9 and 40, and the ASME Code, Section III, Division 1, following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the design of the reactor vessel and vessel supports.

2.2.2.3.4 References

1. Babcock & Wilcox (B&W) Original Reactor Vessel Stress Reports performed under B&W contract numbers 610-0115-51 and 52

2. Combustion Engineering (CE) Report CENC-1166 with Addenda 1 and 2, Analytical Report for Wisconsin Electric Power Reactor Vessel

3. WCAP-14448, Revision 0, Addendum to the Stress Reports for the Point Beach Unit Nos. 1 and 2 Reactor Vessels (RSG/Uprating Evaluation)

4. WCAP-16345-P, Revision 0, with Addenda 1 through 3, Nuclear Management Company – Point Beach Unit 1 Nuclear Power Plant Replacement Reactor Vessel Closure Head – Design Report

5. WCAP-16266-P, Revision 1, with Addenda 1 through 3, Nuclear Management Company – Point Beach Unit 2 Nuclear Power Plant Replacement Reactor Vessel Closure Head – Design Report

6. NUREG/CR-6583, Effects of LWR coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels

7. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

8. WCAP-14422, Licensing Renewal Evaluation: Aging Management for Reactor Coolant System Supports, dated July 1995

9. WCAP-15338, A Review of Cracking Associated with Weld Deposited Cladding in Operating Power Plants, March 2000

10. Specification for the Design, Fabrication and Erection of Strucural Steel for Buildings, AISC, February 1969

Table 2.2.2.3-1
PBNP Baseline Stress Reports

Unit 1	Unit 2
Reference 1 – Original Reactor Vessel Stress Report	Reference 2 – Original Reactor Vessel Stress Report
Reference 3 – RSG/Uprating Program	Reference 3 – RSG/Uprating Program
Reference 4 – Replacement RVCH Program	Reference 5 – Replacement RVCH Program

Table 2.2.2.3-2
EPU Transients Requiring Reconciliation

Transient	Parameter
Unit Loading at 5% of Full Power per Minute	T_{cold}, Pressure
Unit Unloading at 5% of Full Power per Minute	T_{cold}, Pressure
Step Load Increase of 10% of Full Power	T_{cold}
Step Load Decrease of 10% of Full Power	T_{hot}, T_{cold}, Pressure
Large Step Load Decrease with Steam Dump	T_{cold}
Feedwater Cycling	T_{hot}, T_{cold}
Steady-State Fluctuations	T_{hot}, T_{cold}, Pressure
Boron Concentration Equalization	Pressure
Loss of Load (without immediate reactor or turbine trip)	T_{cold}
Loss of Flow	T_{cold}
Reactor Trip from Full Power	T_{cold}

Table 2.2.2.3-3 *Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factors*

Location	Maximum Range of Stress Intensity (ksi)			Cumulative Fatigue Usage Factor		
	Pre-EPU	Post-EPU	Limiting	Pre-EPU	Post-EPU	Limiting
Closure Head at Flange	69.2 – Unit 1 53.0 – Unit 2	69.2 53.0	$69.2 < 3S_m = 80.1$ ksi	0.248 – Unit 1 0.082 – Unit 2	0.248 0.082	0.248 < 1.0
Vessel at Flange	71.1	71.1	$71.1 < 3S_m = 80.1$ ksi	0.945	0.991	0.991 < 1.0
Closure Studs	109.3	109.3	$117.6 < 3S_m = 118.8$ ksi	0.973	0.960	0.960 < 1.0
CRDM Nozzle	44.4	45.3	$45.3 < 3S_m = 60.0$ ksi	0.610	0.672	0.672 < 1.0
Vent Nozzle	52.5	53.6	$53.6 < 3S_m = 60.0$ ksi	0.022	0.023	0.023 < 1.0
IPHA including CETNA	25.6	25.6	$25.6 < 3S_m = 50.1$ ksi	0.029	0.029	0.029 < 1.0
Outlet Nozzle						
Safe End	35.8 – Unit 1 42.3 – Unit 2	35.8 42.3	$35.8 < 3S_m = 49.2$ ksi $42.3 < 3S_m = 49.2$ ksi	not reported(1) not reported(1)		n/a n/a
Nozzle	48.8	48.8	$48.8 < 3S_m = 80.1$ ksi	0.028	0.028	0.028 < 1.0
Support Pad	n/a		n/a	0.122	0.122	0.122 < 1.0
Inlet Nozzle						
Safe End	39.6 – Unit 1 34.6 – Unit 2	42.0 37.0	$42.0 < 3S_m = 52.9$ ksi $37.0 < 3S_m = 52.9$ ksi	not reported(1) not reported(1)		n/a n/a
Nozzle	40.6	40.6	$40.6 < 3S_m = 80.1$ ksi	0.155 – Unit 1 0.021 – Unit 2	0.155 0.039	0.155 < 1.0
Support Pad	n/a		n/a	0.030	0.038	0.038 < 1.0
Safety Injection Nozzles	46.8	46.8	TBD $< 3S_m = 80.1$ ksi	0.200	0.465	0.465 < 1.0
Vessel Wall Transition	32.2	32.2	$32.2 < 3S_m = 80.1$ ksi	0.004	0.006	0.006 < 1.0
Bottom Head to Shell Juncture	28.6	28.6	$28.6 < 3S_m = 80.1$ ksi	0.004	0.004	0.004 < 1.0

Table 2.2.2.3-3 Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factors

Location	Maximum Range of Stress Intensity (ksi)			Cumulative Fatigue Usage Factor		
	Pre-EPU	Post-EPU	Limiting	Pre-EPU	Post-EPU	Limiting
Core Support Pads	57.5	57.5	$57.5 < 3S_m = 69.9$ ksi	0.731	0.960	0.960 < 1.0
External Support Brackets	41.2	41.2	$41.2 < 3S_m = 80.1$ ksi	0.995	0.842[2]	0.842 < 1.0

Note:

1. Cumulative fatigue usage factors were not reported for the safe ends of the outlet and inlet nozzles because the nozzle-to-shell junction, not the safe end, was found to be the worst fatigue location.
2. Number was calculated using a stress concentration factor (SCF) of 1.5 applied to thermal stresses, as determined from a finite element analysis. The pre-EPU cumulative fatigue usage factor applied on overly conservative SCF of 3.27 to the thermal stresses.

Table 2.2.2.3-4
Reactor Vessel/Reactor Internals Interface Loads (lbs)

Location	EPU Interface Load	Allowable Load
Core Barrel - Outlet Nozzle (Horizontal)	52,000	895,000
Vessel Flange – Core Barrel (Horizontal)	0	7,000,000
Vessel Flange – Core Barrel (Vertical)	1,944,000	8,272,000
Core Support Pads (Total Horizontal Load)	1,106,000	3,470,000
Closure Head Flange – Upper Support Plate (Horizontal)	0	1,420,000
Closure Head Flange – Upper Support Plate (Vertical)	1,000,000	5,000,000

Table 2.2.2.3-5
Summary of RPV Support Component Stress Interaction Ratios

Support	Component	Controlling Interaction Ratios (<100%)			
		Normal	Upset	Faulted-1	Faulted-2
RPV Shoe	Screw Shear	18.19%	29.56%	30.23%	35.05%
	Shoe Net Tension	0.05%	14.22%	14.12%	18.18%
Support Structure	Box Beam	21.54%	29.65%	28.35%	36.01%
	Pipe Column	65.52%	90.03%	66.75%	89.49%

Table 2.2.2.3-6
Revised Design Basis EPU RPV Support Loads (per Support)

Loading & Load Combination[1]	Vertical (N) (kips)	Horizontal (V) (kips)
Deadweight	192	0
Thermal	123	0.3
OBE Seismic	110	89
SSE-Seismic	160	177
LOCA	153	51
Normal Combination	315	0.3
Upset Combination	425	89.3
Faulted-1 Combination	475	177.3
Faulted-2 Combination	628	228.3

Note (1) Normal = DW + THM
Upset = Normal + OBE
Faulted-1 = Normal + SSE
Faulted-2 = Normal + SSE + LOCA
Note (2) The RCS primary equipment supports are designed and qualified in accordance with the American Institute of Steel Construction (AISC) "Specification for the Design of Structural Steel for Buildings." The load cases, load combinations, and the applicable allowable stress limits are summarized in FSAR, Table A.5-3, Control Room Building Section, N-S Direction

2.2.2.4 Control Rod Drive Mechanism

2.2.2.4.1 Regulatory Evaluation

Introduction

The evaluation of the PBNP control rod drive mechanisms (CRDM) is an assessment of the impact on the structural integrity of the assemblies from the thermal transients and maximum operating temperatures and pressures that result from the proposed EPU operating conditions. The results of the structural analysis of the CRDM pressure boundary show that the analyzed stresses do not exceed the stress allowable of the ASME Code, and that the cumulative fatigue usage factors from the code fatigue analysis remain less than 1.0.

The CRDMs are mounted onto the reactor vessel (RV) head by means of head adaptors welded to RV head penetrations. The CRDM consists of the internal latch assembly, the pressure vessel, the operating coil stack, the drive shaft assembly, and the position indicator coil stack. Reactor coolant fills the pressure containing parts of the drive mechanism. Thus, the pressure vessel component of the CRDM assembly constitutes a portion of the reactor coolant pressure boundary. The housings are designed in accordance with the requirements of the ASME Code, Section III, Class 1, 1998 Edition through 2000 Addenda.

This section addresses the ASME Code of record structural considerations for the pressure boundary components of the full-length model L-106A control rod drive mechanisms (CRDMs). The CRDMs were evaluated using the NSSS operating parameters of LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1, and the NSSS design transients of LR Section 2.2.6, NSSS Design Transients developed for the PBNP EPU program.

The PBNP CRDMs were replaced in the U1R29 and U2R27 refueling outages in 2005 with equivalent units (Model L-106A) as part of the reactor vessel head replacement program.

Control Rod Drive Mechanisms are described in FSAR Sections 3.1, Reactor, Design Basis, 3.2.3, Mechanical Design and Evaluation, 3.4, Functional Design of the Reactivity Control Systems, 4.2, RCS System Design and Operation, 5.3.2.1, Containment Air Recirculation, 7.2.2.1, Reactor Protection System Description, 15.4.2, Fatigue and Appendix A5.3, Class I Design Criteria for Vessels and Piping.

As described in the FSAR Section 3.4, Reactor, Functional Design of Reactivity Control System, each control rod drive assembly is designed as a hermetically sealed unit to prevent leakage of reactor coolant water. All pressure-containing components are designed to meet the requirements of the ASME Code, Section III, Nuclear Vessels for Class 1 Vessel appurtenances. Control rod drive assemblies are mounted on the top of the reactor vessel and are considered an extension of the reactor vessel head.

PBNP Current Licensing Basis

The generic Current Licensing Basis in LR Section 2.2.2, Pressure Retaining Components and Component Supports, above applies to control rod drive mechanisms.

The CRDM components evaluated herein for the proposed EPU are discussed in NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005 in Sections 3.0 and 3.1 (Reference 1) , primarily as they relate to the industry operating experience of incidents of primary pressure boundary degradation due to primary water stress corrosion cracking (PWSCC). Regarding the programs used to manage the aging effects associated with these components (AMPs), a discussion of PBNP RV head replacement program is provided in LR Section 2.1.5, Reactor Coolant Pressure Boundary Materials. The head replacement project included replacing CRDMs with RV head penetrations fabricated with materials that provide enhanced resistance to PWSCC.

Analysis of flow induced vibration with respect to CRDMs is not included in the licensing basis for PBNP. However, it was considered for more susceptible components that would experience a significant flow increase under EPU conditions. CRDMs were evaluated and are unaffected by EPU conditions and have not been analyzed for FIV.

2.2.2.4.2 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

The Model L-106A CRDMs were originally designed and analyzed to meet the ASME Code. Plant specific analyses of record (AOR) for Model L-106A CRDMs were the bases for this evaluation. The Performance Capability Working Group (PCWG) parameters and Nuclear Steam Supply System (NSSS) design transients developed for the PBNP EPU were used as the new inputs for this evaluation. The seismic and loss of coolant accident (LOCA) loads specific to PBNP changed from those used in the AOR due to updated reactor vessel support stiffnesses, and not from the EPU program. However, the new seismic and LOCA loads were evaluated for the EPU. The PBNP CRDMs are of the hot reactor vessel head type, and are defined by the vessel outlet reactor coolant temperature, T_{hot}, in LR Section 1.1, NSSS Parameters. Therefore, this analysis used the NSSS design transients that are defined for the hot leg.

The acceptance criteria for the ASME Code structural analysis of the CRDM reactor coolant pressure boundary are that the analyzed stresses do not exceed the allowable stresses of the ASME Code, and that the cumulative fatigue usage factors from the code fatigue analysis do not exceed 1.0. For those cases for which changes to the design transients would have allowed a decrease in stresses or cumulative usage factors, no decrease was calculated, and no credit was taken for such a decrease.

Description of Analyses and Evaluations

Operating Pressure and Temperature

The NSSS temperatures and pressures developed for the PBNP EPU program (as given in LR Section 1.1, NSSS Parameters) were compared to those used for the AOR. There is no change in the reactor coolant pressure of 2250 psia for any EPU cases. The hot leg temperature (T_{hot}), defined by the vessel outlet temperature, is a maximum of 611.1°F. This temperature is less than the 611.3°F temperature used in the AOR. Since none of the temperatures exceed the previously analyzed temperature and the pressure does not change, the NSSS parameters developed for the EPU program and used for this evaluation are bounded by the generic analyses for Model L-106A CRDMs.

Transient Discussion

The NSSS design thermal and pressure transients, discussed in LR Section 2.2.6, were compared to those used for the AOR. The EPU program NSSS design transients were determined to be bounded; therefore, there is no impact on the stress intensities.

Seismic and LOCA

The seismic and LOCA response spectra considered in the EPU evaluation differed from those considered in the AOR. They were not different because of the uprate, they were different because of updated reactor vessel support stiffness values. The updated and AOR response spectra were compared to evaluate the impact of the revised support stiffness. The new spectra exceeded that from the AOR, creating new PBNP specific dynamic loads. The new dynamic loads remain bounded by the umbrella loads used in the AOR.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The NSSS design thermal and pressure transients, discussed in LR Section 2.2.6 remain bounded by the original analyses, so that the conclusion by the NRC staff in NUREG-1839 (Reference 1)(the license renewal SER) Section 4.3.3 that the structural integrity of the PBNP CRDMs will be maintained during the period of extended operation remains valid. Therefore, the license renewal evaluation for the CRDMs remains valid including the effects of EPU.

2.2.2.4.3 Results

The PCWG parameters (LR Section 1.1, NSSS Parameters) and NSSS design transients (LR Section 2.2.6, NSSS Design Transients) were bounded by the existing parameters and transients used for the AOR. The revised seismic and LOCA loads were also bounded by those used for the AOR. Therefore, the results from the AOR remain bounding and applicable to the PBNP 1 and 2 EPU. The summary of the stress analysis results for the Upper Latch Housing (ULH) and the Lower Latch Housing (LLH) is given in Table 2.2.2.4-1, Stress Analysis Results for the ULH(3), and Table 2.2.2.4-2, Stress Analysis Results for the LLH(3), respectively. The Rod Travel Housing (RTH) structural qualification is enveloped by the similar analysis completed for the ULH.

2.2.2.4.4 Conclusions

PBNP has reviewed the evaluation related to the structural integrity of pressure-retaining components of the CRDM. For the reasons presented above, PBNP concludes that the effects of the proposed EPU on these components have been adequately addressed. PBNP further concludes that these pressure-retaining components will continue to meet the requirements of PBNP GDC 1, 2, 40 and 9 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components of the CRDM.

2.2.2.4.5 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.2.2.4-1

Stress Analysis Results for the ULH[3]

Analysis	Category	ASME Code	Allowable (ksi)	SINT (ksi)	M.S.[1]
Structural Qualification	Design/Normal/Upset	NB-3221.1	$1.0S_m = 16.70$	15.49	0.08
		NB-3221.3	$1.5S_m = 25.05$	23.75	0.05
		NB-3222.2	$3.0S_m = 50.10$	54.9	1.17[2]
		NB-3227.4	$4.0S_m = 66.80$	33.7	0.98
		NB-3222.5(d)	1.0 (ratio)	Ratio = 0.37 (linear)	
				Ratio = 0.27 (parabolic)	
	Faulted	NB-3225 F-1331.1(a)	$2.4S_m = 40.08$	16.68	1.4
		NB-3225 F-1331.1(c)	$3.6S_m = 60.12$	52.95	0.14
Fatigue Usage Factor					U = 0.364

Notes:

1. M.S. (Margin of Safety) = (S_{ALL}/SINT)-1, where S_{ALL} is the allowable stress intensity and SINT is the actual stress intensity calculated.
2. NB-3228.5 (simplified elastic-plastic analysis) applies. Primary plus secondary stress, excluding thermal bending, is below the $3S_m$ allowable value.
3. All values applicable to current and EPU power levels.

Table 2.2.2.4-2
Stress Analysis Results for the LLH[3]

Analysis	Category	ASME Code	Allowable (ksi)	SINT (ksi)	M.S.[1]
Structural Qualification	Design/Normal/Upset	NB-3221.1	$1.0S_m = 16.70$	15.06	0.11
		NB-3221.3	$1.5S_m = 25.05$	15.06	0.66
		NB-3222.2	$3.0S_m = 50.10$	58.17	2.96[2]
		NB-3227.4	$4.0S_m = 66.80$	19.11	2.5
		NB-3222.5(d)	1.0 (ratio)	Ratio = 0.69 (linear)	
				Ratio = 0.48 (parabolic)	
	Faulted	NB-3225 F-1331.1(a)	$2.4S_m = 40.08$	12.28	2.26
		NB-3225 F-1331.1(c)	$3.6S_m = 60.12$	38.51	0.56
Fatigue Usage Factor					U = 0.043

Notes:

1. M.S. (Margin of Safety) = $(S_{ALL}/SINT)-1$, where S_{ALL} is the allowable stress intensity and SINT is the actual stress intensity calculated.
2. NB-3228.5 (simplified elastic-plastic analysis) applies. Primary plus secondary stress, excluding thermal bending, is below the $3S_m$ allowable value.
3. All values applicable to current and EPU power levels.

2.2.2.5 Steam Generators and Supports

Introduction

The steam generators have been evaluated for operation at the EPU conditions specified in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1, and contained in the steam generator certified design specification. The steam generators are described in the FSAR Chapter 4. Evaluation of the steam generators has demonstrated continued compliance with applicable regulatory and industry structural integrity and thermal-hydraulic performance requirements following the implementation of EPU. The steam generators were also evaluated to demonstrate that failure due to tube vibration and wear does not occur. The evaluations considered an EPU full-power core thermal power level of 1800 MWt (nuclear steam supply system (NSSS) power level of 1806 MWt), steam generator tube plugging (SGTP) over the range from 0% to 10%, with a primary average temperature (T_{avg}) window from 558.0° to 577°F, a full-load steam generator outlet pressure ranging from 601 to 755 psia, and a feedwater temperature window from 458° to 390°F Postulated steam generator design transients that are affected by the EPU were addressed in the evaluations.

The steam generator and supports evaluation was performed in 11 separate, but coordinated, subsections:

- Steam Generator Structural Integrity Evaluation
- Primary-to-Secondary Side Pressure Differential Evaluation
- Steam Generator Thermal-Hydraulic Analysis
- Steam Generator Tube Wear
- Steam Generator Loose Parts
- Steam Generator Hardware Evaluation
- Steam Drum Component Evaluation
- Steam Generator Chemistry Evaluation
- Regulatory Guide 1.20 Evaluation
- Structural Evaluation of Increased Primary-to-Secondary Pressure
- Steam Generator Supports

The following separate subsections within this Licensing Report section describe each analysis; its input parameters, assumptions, and acceptance criteria; the impact of EPU on each topic within the License renewal application/approval; and provide results and a conclusion regarding the topic. A collective finding (Section 2.2.2.5.15) regarding the adequacy of the steam generators and supports under EPU conditions concludes this LR subsection.

2.2.2.5.1 Regulatory Evaluation

PBNP Current Licensing Basis

The generic Current Licensing Basis in LR Section 2.2.2, Pressure-Retaining Components and Component Supports, applies to steam generators and supports, with the following amplifications:

PBNP Units 1 and 2 began commercial operation with Westinghouse Model 44 steam generators. In 1983, PBNP replaced the Model 44 steam generators in Unit 1 with Westinghouse Model 44F steam generators. In 1996, PBNP installed the Westinghouse Model Δ47 steam generators in Unit 2. The work done to support this program is documented in WCAP 14602, Point Beach Nuclear Plant Unit 2 Steam Generator Replacement Engineering Report, March 1996, Reference 13.

For Unit 2, in 1996 PBNP prepared the necessary license amendment requests to implement the steam generator replacement program (SGRP). At that time, PBNP did not request a power uprate, even though the system and component analyses were performed at uprated power conditions. The SGRP was approved by the Nuclear Regulatory Commission (NRC) and the steam generators were subsequently replaced in Unit 2 in December 1996.

All of the new components of the Unit 1 Steam Generators were fabricated in accordance with the 1977 ASME Boiler and Pressure Vessel Code, Section III, through Winter 1978 Addenda (Reference 14). The upper shells and the original components that remained in the units were designed to the 1965 ASME Code through Summer 1966 Addenda. The stress report for the new components is also in accordance with the 1965 ASME Code through Summer 1966 Addenda.

The upper and lower assemblies for the Unit 2 steam generators were designed and manufactured in accordance with the 1986 ASME Code, Section III, NB requirements (Reference 15).

Except for the U-tubes, the steam generator internal components are not governed by the ASME Code; however, the ASME B&PV Code Class 1 requirements were used as a guide for their design. The internal components were required to withstand all specified loadings to maintain heat transfer capabilities during and following a design basis earthquake (DBE). In addition, it was shown that the U-tubes do not deform as a result of a DBE.

The steam generators were also designed to maintain tube integrity following an instantaneous full rupture of the steam line downstream of the steam outlet nozzle during full-power operation. This evaluation was in accordance with criteria from the ASME Code, Section III for Level D conditions. Tube integrity was also demonstrated following a small steam line break in accordance with criteria from the ASME Code, Section III for Level C conditions.

An analysis of the steam generators was performed to ensure that the U-tubes are adequately supported to avoid significant levels of tube vibration causing wear and fatigue. The analysis was performed to PBNP specification requirements and industry accepted criteria.

By meeting the acceptance criteria discussed in the various sections below, the portion of the RCPB formed by the steam generators and tubing will continue to meet all the specified criteria at the EPU conditions.

In addition to the evaluations described in the introduction section above, the steam generators and supports were evaluated for plant license renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), December 2005 (Reference 8)

The results of the NRC review of the steam generators are documented in Section 2.3.1.5. Time Limited Aging Analysis (TLAA) and the programs used to manage aging were evaluated in Section 4.3.4. The Steam Generator Integrity Program is discussed in SER Subsection 3.0.3.2.18.

2.2.2.5.2 Steam Generator Structural Integrity Evaluation

Technical Evaluation

Introduction

The structural evaluation focuses on steam generator component stress ratios and fatigue usages. A comparison of pre-EPU and post-EPU transient parameters was performed to determine scaling factors/stress changes that could then be applied to the component stresses in the baseline analyses.

For the primary side components considered (the divider plate, the tubesheet and shell junctions, the tube-to-tubesheet weld and tubes), the applicable scaling factors are the ratios of the primary-to-secondary side differential pressures (ΔPs) for the baseline condition to the ΔPs for the uprated conditions. Thermal effects as a result of the EPU are minimal due to the small change in primary side temperatures. The scaling factors calculated are applied to both pressure and thermal stresses calculated in the baseline analysis and envelop the thermal effects of the EPU on the primary side components.

For the secondary side components, the difference in secondary side operating pressure and the resulting pressure stress change are the basis for determining the change in the stress range and fatigue usage. It is assumed that the pressure stress change always adds to the pressure range and thus increases the fatigue usage for those transients affected. In the case of the feedwater nozzles, it was necessary to also include an increase in thermal stress to account for the lower end of the feedwater temperature range analyzed. The change in feedwater temperature does not have any significant impact on the stresses for other secondary side components evaluated. The modified stresses are considered in determining the stress ranges involving transients that originate from, or lead to, full power. The increased stress ranges are addressed in the evaluation of the secondary side components and factored into the calculation of the fatigue usage.

Input Parameters, Assumptions, and Acceptance Criteria

The applicable parameters used for the steam generator structural evaluation are shown in LR Section 1.1, Nuclear Steam Supply System Parameters. The design transients discussed in

LR Section 2.2.6, NSSS Design Transients, and the results of the primary-to-secondary side ΔP calculation discussed in LR Section 2.2.2.5.13, Structural Evaluation of Increased Primary-to-Secondary Pressure Differential, were used to generate scaling factors with respect to the original stress reports results.

The major assumptions used in this analysis are:

- For the primary side components, scaling factors based on the difference in the primary-to-secondary side pressure differential are used to calculate the increase in stress ranges due to the uprate. These scaling factors are a ratio of the pressure differential for the EPU to that of the baseline analysis. These scaling factors are calculated for each transient and are applied to the maximum stress intensity ranges used in the baseline analysis to demonstrate compliance with ASME Code stress limits and fatigue usage. Applying these factors to the entire stress conservatively increases both the pressure and thermal components of the stress. No credit is taken for any ratio that is calculated to be less than 1.0.
- Changes to the stress ranges calculated for secondary side components are primarily due to changes in steam pressure as a result of the EPU. While this pressure may decrease, the effect of the change is assumed to always increase the stress range used in calculating the fatigue usage for that component. Changes occur to the minimum and maximum steam pressure. The maximum change in pressure between the baseline/EPU maximum pressures or minimum pressures is used to modify the calculated EPU stress ranges.
- Thermal effects and the fatigue analysis for the secondary side components are generally driven by transients that are not affected by the uprate, i.e., test, heatup/cooldown, excessive feedwater, etc. Only the feedwater system is significantly affected by temperature changes. These changes are the result of increasing/decreasing the feedwater temperature. This effect is considered in the evaluation of the feedwater nozzle through the use of a temperature scaling factor that is applied to the affected thermal transients. For all other components, the thermal effects are considered to be negligible.

The acceptance criteria for each component are consistent with the criteria used in the design basis analysis for that component, and as reported in the original stress reports and supplemental design basis calculations. The maximum range of primary-plus-secondary stress was compared with the corresponding $3S_m$ limit of the ASME Boiler & Pressure Vessel Code Section III (1965 Edition through the Summer 1966 Addenda). For situations where the $3S_m$ limit was exceeded, a plastic analysis or a simplified elastic-plastic analysis was performed consistent with the original design basis analysis.

A cumulative fatigue usage factor less than or equal to 1.0 demonstrates design adequacy for fatigue over the specified design life of the component.

Description of Analyses and Evaluations

Primary Side Components

For primary side components, the scaling factor was calculated based on the primary-to-secondary side differential pressure before (baseline) and after the EPU. The scaling factors are applied to the total stress range affected. The resulting stress ranges are compared to the appropriate primary-plus-bending stress allowable and are used to recalculate the fatigue usage factor for the component.

Secondary Side Components

The change in stress to the secondary side components is dependent on the changes in the steam pressure as a result of the EPU. The increase in stress results from a change in the steam pressure, either High or Low T_{avg}, between the baseline analysis parameters and those for the EPU. The additional stress was then added to the stress range and used to calculate the fatigue usage for operation at EPU conditions. In the case of the feedwater nozzle, the feedwater temperature can reach a minimum temperature of 390°F. The difference between this temperature and the feedwater temperature evaluated in the baseline analysis, 440°F (Unit 2) and 435.7°F (Unit 1), results in an increase in the temperature gradient across the feedwater nozzle and will result in an increase in thermal stress. Scaling factors based on the temperature differences expected as a result of the uprate are calculated for transients affected by a change in feedwater temperature, and the thermal stress intensity is modified by the scaling factor. The new stress range is computed and compared to Code allowables, and the fatigue usage is recalculated for the EPU conditions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As an integral part of the License Renewal Program, the PBNP Steam Generator Integrity Program manages aging effects such as cracking due to primary water stress-corrosion cracking (PWSCC), outside diameter stress-corrosion cracking (ODSCC), IGA, pitting, wastage, wear fouling due to corrosion product buildup, mechanical degradation due to denting and impingement damage. The Steam Generator Integrity Program manages these aging effects/mechanisms through a balance of prevention, inspection, assessment, evaluation, repair, and leakage monitoring measures. Key program attributes include nondestructive examination (NDE), sludge lancing, primary and secondary water chemistry control, and primary-to-secondary leakage trending and monitoring. The Program is evaluated in the License Renewal SER, NUREG-1839 (Reference 8), Section 3.0.3.2.18.

The structural integrity evaluation for the EPU operating conditions demonstrated that the steam generators continue to comply with the ASME fatigue requirements for a 60 year60 year life.

Changes in water/film velocities and operating temperatures for the EPU operating conditions may affect the flow-assisted corrosion rates. However, the variations are within the scope of the aging management evaluation performed for license renewal. Therefore, the conclusions reached in NUREG-1839 (Reference 8) for the steam generators and the Steam Generator Integrity Program remain valid at EPU conditions.

2.2.2.5.3 Results

The normal/upset maximum stress intensity range and fatigue usage factors are provided in Table 2.2.2.5-1, PBNP Unit 1 Model 44F EPU Stress Summary, and Table 2.2.2.5-2, PBNP Unit 2 Model D47 EPU Stress Summary, for primary side and secondary side components. All other stresses not calculated as part of this evaluation are not significantly impacted by the EPU, and the baseline stress results remain applicable.

The fatigue usage factors and primary-plus-secondary stress intensities for all primary and secondary side components have been evaluated to Code requirements and have been shown by analyses that applied the scaling factors described above to be acceptable following the EPU.

2.2.2.5.4 Conclusions

Operation under EPU conditions will not adversely affect the structural integrity of the evaluated steam generator components.

2.2.2.5.5 Primary-to-Secondary Side Pressure Differential Evaluation

Technical Evaluation

Introduction

An analysis was performed to calculate the maximum primary-to-secondary pressure drops for Units 1 and 2 for the EPU. A ΔP evaluation was performed for High T_{avg} and Low T_{avg} conditions at 10% tube plugging levels. Because the parameters and transient descriptions envelop the Unit 1 Model 44F SG and the Unit 2 Model Δ47 SG, the analysis results are applicable to both units.

Input Parameters, Assumptions, and Acceptance Criteria

Calculations to determine the primary-to-secondary side pressure gradients are based on the steady-state operating parameters in LR Section 1.1, NSSS Parameters. The revised design transients resulting from the EPU are provided in LR Section 2.2.6, NSSS Design Transients.

An analysis was performed to evaluate the increase in the primary-to-secondary side pressure differential to 1700 psi. The results of that analysis provide the higher pressure limit used in the primary-to-secondary side pressure differential evaluation.

Description of Analyses and Evaluations

This evaluation reviewed the applicable EPU Normal and Upset transients defined in LR Section 2.2.6, NSSS Design Transients, to determine if the increased allowable primary-to-secondary pressure differential is exceeded at any time during the transients. The starting point for these transients is the 100% power level parameters defined in LR Section 1.1, NSSS Parameters. The original allowable of 1550 psi was applicable to those components which provide the boundary between the primary and secondary side of the steam generator, i.e. tubesheet and tubes. Through additional analysis, this pressure limit has been increased to 1700 psi, and this higher limit was used in this evaluation.

The conservative steam pressures used for this evaluation are those at the steam nozzle. Since the primary-to-secondary pressure differential limit is the pressure across the primary pressure boundary, the pressure drop from the top of the tube bundle to the steam nozzle can be used to reduce the calculated pressure differential, if necessary, to demonstrate that the 1700 psi differential pressure criterion is met.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached for the evaluation of the Steam Generator Integrity Program in the PBNP License Renewal Application. PBNP has concluded that the Steam Generator Integrity Program remains adequate, following implementation of the EPU.

Results

A summary of the analysis results for the High and Low T_{avg} conditions with 10% tube plugging is provided in Table 2.2.2.5-3, Delta-P Summary for PBNP Unit 1 (Model 44F SG) and Unit 2 (Model D47 SG) 10% Plugging. Since the parameters upon which the primary-to-secondary differential pressure analysis were based bound both units, the limiting Unit 2 results are presented. These results show that for the EPU, the primary-to-secondary side pressure differential of 1700 psia and 1870 psi are met for Normal and Upset conditions, respectively. Since the pressure differential is a limit on the primary-to-secondary side pressure boundary, i.e., tubesheet and tubes, it is appropriate to reduce the calculated pressure differences by the pressure drop from the top of the tube bundle to the steam nozzle if the pressure differential limit is exceeded. Since the 1700 psia limit was exceeded for the Low T_{avg} condition with 10% tube plugging, the pressure differential between the top of the tube bundle and the steam nozzle was subtracted from the maximum pressure difference, resulting in a pressure differential of 1685 psi which meets the allowable limit of 1700 psi. All other conditions meet the allowable limits without modification.

Conclusions

The primary-to-secondary side pressure differential limits for Normal and Upset conditions will not be exceeded during operation under EPU conditions.

2.2.2.5.6 Steam Generator Thermal-Hydraulic Analysis

Technical Evaluation

Introduction

Each PBNP unit has two U-tube recirculating type steam generators. Unit 1 has two Westinghouse Model 44F steam generators while Unit 2 has two Westinghouse Model Δ47 steam generators. A total of 112 modular primary moisture separators are installed in each Unit 1 and Unit 2 steam generator.

Thermal-hydraulic evaluations were performed to assure that the PBNP Unit 1 and Unit 2 steam generators (SGs) remain within acceptable bounds after implementing the extended power uprate (EPU). Key thermal-hydraulic factors of interest include: (1) the potential for tube dryout, (2) hydrodynamic stability, and (3) moisture carryover (MCO).

Input Parameters, Assumptions, and Acceptance Criteria

Design basis thermal-hydraulic operating conditions for PBNP Units 1 and 2 are provided in LR Section 1.1, NSSS Parameters.

The acceptance criteria for the PBNP Unit 1 and Unit 2 steam generators at EPU conditions are:

- Local dryout does not occur on tube bundle
- Steam generators are hydrodynamically stable
- Moisture carryover is less than 0.25%

Description of Analyses and Methodology

GENF and ATHOS are verified and validated computer programs used to evaluate the thermal-hydraulic performance of Westinghouse Model 44F and Δ47 vertical U-tube steam generators. GENF performs a steady-state thermal-hydraulic analysis of an entire steam generator. ATHOS is a suite of sequentially-executed modules that performs steady-state analysis of tube bundle thermal-hydraulics.

The GENF code calculates a damping factor to predict the hydrodynamic stability of a steam generator. A negative damping factor indicates that the steam generator is hydrodynamically stable. GENF also calculates the circulation ratio, separator pressure drops, primary inlet temperature, and steam flow rate that are imposed as boundary conditions on the ATHOS steam generator model.

Subsequent analysis using ATHOS with boundary conditions derived by GENF produce a three-dimensional flow field of the secondary side of the steam generator tube bundle. This analysis evaluates the potential for local tube wall dryout by calculating the ratio of local quality (x) to the quality corresponding to Departure from Nucleate Boiling (x_{DNB}); a quality ratio (x/x_{DNB}) less than one indicates no potential for dryout within the tube bundle. Quality ratios of 1.0 or slightly greater are acceptable for small regions of the tube bundle if the operating conditions and configuration of plugged tubes is sufficiently conservative. A configuration for which all plugged tubes are located at the periphery of the tube bundle is most conservative since the entire primary-to-secondary heat transfer must then occur across the least tube surface area. ATHOS is also used to determine liquid and vapor mass flow rates to the primary moisture separators for input to the moisture carryover evaluation.

Steam generator moisture carryover for PBNP after implementing the EPU is less than 0.25% and is determined at best estimate conditions from separator loads calculated by ATHOS through the following steps:

- Establish a maldistribution multiplier through a comparison of unit cell tests and plant data
- Project three-dimensional steam-water loadings of individual primary separators to estimate dryer inlet moisture, steam velocity, and steam pressure (Kutateladze parameter)
- Use the dryer inlet moisture and Kutateladze parameter in a three-dimensional design basis correlation to estimate moisture carryover

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached for the evaluation of the Steam Generator Integrity Program in the PBNP License Renewal SER. PBNP has concluded that the Steam Generator Integrity Program remains adequate, following implementation of the EPU.

Steam Generator Thermal-Hydraulic Results

The thermal-hydraulic performance of the Unit 1 and Unit 2 steam generators was evaluated at bounding and best estimate EPU conditions for local dryout, moisture carryover, and hydrodynamic stability. For Unit 1, local dryout, moisture carryover, and hydrodynamic stability results at EPU conditions were found to be acceptable.

For Unit 2, moisture carryover and hydrodynamic stability at EPU conditions were found to be acceptable. Local dryout is discussed below.

Local Dryout

For both PBNP Units 1 and 2, the x/x_{DNB} quality ratio increases with elevation in the tube bundle and peaks in the U-bend region with the hot side exhibiting a higher ratio than the cold side. The maximum DNB ratio typically increases as steam generator pressure decreases; therefore, for local dryout concerns, the lower pressure case bounds the higher pressure case.

For Unit 1 the x/x_{DNB} ratio for the bounding case only slightly exceeds one and only within a very small region of the U-bend. The x/x_{DNB} ratio is much less than one throughout the tube bundle for the best estimate case. Given the conservative operating conditions for the bounding cases and the conservative configuration of plugged tubes assumed for the ATHOS model, local dryout within the tube bundle is not a concern for Unit 1.

The Unit 2 Model Δ47 steam generators will not experience dryout under best estimate conditions. The P Unit 2 Model Δ47 steam generator will not experience dryout under EPU conditions for low tube plugging levels. There is a potential for tube bundle dryout at high tube plugging levels, and, for a given level of tube plugging, this potential increases as the average primary temperature T_{avg} decreases.

Under EPU design conditions with average primary temperature within the specified EPU range, the Unit 2 steam generators will not experience dryout for low tube plugging levels less than approximately 3%. Between 3% and 8% tube plugging, the potential for tube plugging imposes a lower limit on the average primary temperature. This limit on low T_{avg} increases as the level of tube plugging increases. At a tube plugging level of approximately 8%, the limit on low T_{avg} equals high T_{avg}. No dryout is predicted under Best Estimate conditions.

Moisture Carryover

The PBNP steam generators will be modified to reduce moisture carryover to less than or equal to the design basis of 0.25%. The anticipated modifications include:

- Reduce the mid-deck inlet vent area by 85% as compared to the existing vent area by installing mid-deck extension plates; change the open top pipe vent design to a flow diverter vent pipe design with vent caps to prevent direct entry of the steam/water vent flow into the gravity space
- Replace the formed vanes in the double tier secondary separators by double pocket vanes

Moisture carryover with these modifications is projected to be less than 0.25% at best estimate conditions.

Hydrodynamic Stability

The hydrodynamic stability of a steam generator is characterized by the damping factor. A negative damping factor indicates a stable unit where small perturbations of steam pressure or flow rate will diminish with time rather than grow in amplitude. For Units 1 and 2, the damping factor remains at a high negative value for all cases analyzed. Therefore, the PBNP steam generators are expected to continue to be hydrodynamically stable at all operating conditions after the proposed EPU.

Conclusions

Under EPU conditions, moisture carryover with the planned mid-deck and secondary separator modifications is projected to be less than 0.25% at best estimate conditions, and the steam generators are expected to remain hydrodynamically stable. Local dryout of the tube bundle under EPU conditions is not a concern for Unit 1, and is not predicted to occur for Unit 2 under Best Estimate conditions.

2.2.2.5.7 Steam Generator Tube Wear

Technical Evaluation

Introduction

The impact of the proposed EPU on Unit 1 Model 44F and Unit 2 Model Δ47 steam generator tube wear was evaluated based on the current design basis analysis and consideration of the changes in the thermal-hydraulic properties of the secondary side of the steam generator resulting from the uprate. Wear in the steam generator tubes due to fluidelastic effects in the U-bend region of the tubes and due to turbulence induced displacement effects in the straight-leg region of the tubes was considered.

Input Parameters, Assumptions and Acceptance Criteria

The design basis flow-induced vibration calculations for Units 1 and 2 are input into the evaluation along with the actual wear rates measured in the field as part of the SG inspection program. This information is provided in the condition monitoring and operational assessment (CMOA) documents generated following SG inspection. The latest available data is used to determine wear rates for recorded flow-induced vibration (FIV) wear indications.

The following major assumptions are used in this evaluation.

1. Fluidelastic instability values are modified by ratios of ρV^2
2. Turbulence displacement values are modified by ratios of $(\rho V^2)^2$
3. Wear values are modified by ratios of $(\rho V^2)^2$

Where root-mean-squared (RMS) values are reported in the literature, a reasonable approximation of the peak value is obtained by applying a factor of 3.5 to arrive at the peak value.

The following acceptance criteria have been developed:

1. Fluidelastic stability ratios < 1.0

2. Amplitude of tube vibration due to turbulence no greater than ½ of the gap between tubes. This considers the worst-case scenario that the adjacent tubes are moving 180 degrees out of phase.

   Unit 1 Gap = 1/2 * (1.2344 - 0.875) = 0.1797 inch

   Unit 2 Gap = 1/2 * (1.234 - 0.875) = 0.1795 inch

3. Demonstrate that unacceptably large rates of tube wear will not occur after the uprate. Note that 40% wear depth for the Model 44F and Δ47 steam generators would be 0.4 × 50 mils = 20 mils.

4. FIV-induced tube stresses remain below the fatigue endurance limit of the material.

Description of Analyses and Evaluations

Results from the original vibration and wear analyses were modified to account for changes in the secondary side operating conditions associated with the most limiting of the proposed EPU operating conditions. A review of the Unit 1 FIV results does not indicate any wear degradation as a result of flow-induced vibration. Based on analysis for Unit 2, less than 3 mils over a 40 year life, and analysis for other models of steam generators, the reported wear is typically small and not a concern even for a large uprate. To address the effect on wear, the latest CMOA for Unit 1 and Unit 2 is used to address actual measured wear rates for tubes exhibiting wear found by eddy current testing.

Results

The analysis indicates that as a result of the proposed uprate, unacceptable levels of tube vibration will not occur from either fluidelastic or turbulent mechanisms. Results of the uprate analysis show that the fluidelastic stability ratio could increase by as much as [ ] ^{a,c} %, while the turbulence would increase by as much as [ ] ^{a,c} %. This results in a maximum stability ratio of [ ] ^{a,c} (less than the allowable of 1.0) and maximum turbulence-induced amplitude of [ ] ^{a,c} mils, (less than 1/2 the distance separating the tubes, or approximately 179 mils for either unit). Both conditions remain acceptable following the uprate.

The maximum pre-uprate predicted wear for the tubes is < [ ] ^{a,c} inch over the 40 year design life of the Unit 2 Δ47 steam generators. The power uprate increases the tube wear by [ ] ^{a,c} % over that calculated for the original design power level. The maximum post-uprate wear over 40 years is less than [ ] ^{a,c} mils. This amount of wear will not significantly affect tube integrity and is judged to be acceptable. A review of similar steam generator models to the Model 44F steam generators in Unit 1 shows that the Unit 2 wear results are typical for replacement steam generators. Therefore, the proposed uprate is not projected to result in an unacceptable rate of tube wear for Unit 1.

Only a small number of tubes in the Unit 1 and Unit 2 steam generators have demonstrated any wear based on eddy current testing. All of this wear is in the vicinity of the anti-vibration bars (AVBs) and is evaluated in the CMOA reports prepared following inspection. A review of the latest CMOA reports for Units 1 and 2 shows that for an increase in wear rate of [ ] ^{a,c}%, tube wear based on the 95th percentile wear growth rate is acceptable based on the latest inspection data. Therefore, the effects of the EPU will not affect the integrity of tubes currently showing wear for the inspection interval following uprate.

Fatigue usage associated with general flow-induced vibration resulting from the most limiting uprated operating condition indicates that the corresponding maximum stress levels would be less than [ ] ^{a,c} ksi for either unit. This level of stress remains well below the endurance limit of approximately 20 ksi at 1E11 cycles. Hence, the fatigue usage factor associated with the FIV tube loadings in the uprated operating condition is negligible and, therefore, acceptable.

Evaluation of high cycle fatigue in the tubes has also been addressed. This condition is a result of various factors, including a build-up of corrosion products associated with drilled holes in carbon steel tube support plates (TSPs). Since the stainless steel support plates used in the Unit 1 and 2 steam generators are designed to inhibit the introduction of corrosion products, the support condition (i.e., tube denting) necessary for the development of high cycle fatigue cannot occur. As a result, high cycle fatigue issues associated with unsupported inner row tubes cannot occur in the Unit 1 and Unit 2 steam generators and is not a concern.

Conclusions

Thermal-hydraulic properties of the secondary side of the steam generators under EPU conditions have been evaluated for their effects on tube vibration mechanisms and associated tube wear and fatigue. EPU effects on tube wear and fatigue are acceptable.

2.2.2.5.8 Steam Generator Loose Parts

Technical Evaluation

Introduction

During the spring 2004 outage for Unit 1, it was determined that one irretrievable foreign object (small wire) was located in the secondary side of the "A" SG. Calculations were performed which determined that the object could remain in the SG for at least two fuel cycles of operation.

Additionally, during the fall 2003 outage for Unit 2, it was found that various irretrievable foreign objects (small wires) were located in the secondary side of the "A" SG. Calculations were performed which determined that the objects could remain in the SG for at least two fuel cycles of operation.

An analysis was performed for EPU conditions (1806 MWt NSSS plant power level) to determine if the modified operating conditions would affect the previously calculated wear-time analysis on the secondary side due to loose parts located in the secondary side.

Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The current analysis considers:

- Previously calculated wear times from the 2003 (Unit 2) and 2004 (Unit 1) outages
- Secondary side thermal-hydraulic conditions for each of the EPU conditions

Major assumptions in the current analysis include:

- A pre-existing wear scar of [ ]$^{(a,c)}$ % wear depth is present on the tubes. Normal tube eddy current inspections verify that this conservative value is not exceeded
- The SGs are operating at EPU conditions

Acceptance Criteria

- The effects of the uprate do not significantly affect the previous wear time evaluations and/or do not worsen the wear environment.
- The projected wear levels are sufficiently low so as to permit operation through a complete cycle (cycle range approximately 1.5 years) prior to the need for another inspection.

Description of Analyses and Evaluation

Secondary Side Loose Part Analysis

With certain changes in SG operating conditions such as power level, feedwater temperature, steam pressure, or plugging level, there could be a corresponding change in the thermal-hydraulic characteristics relevant to loose part induced tube wear. Calculations were performed in the original loose part analyses to identify secondary-side flow characteristics that could influence tube vibration and corresponding loose part wear. Loose part wear is a function of drag force and tube displacement. Since both drag force and displacements are a function of density and velocity, a comparison was made between the square of the density times velocity squared for each of the proposed uprate conditions. In all cases the EPU conditions are less severe than the originally evaluated condition since all ratios are less than 1.0. Therefore, the original evaluation bounds the EPU conditions.

Results

For the secondary side loose parts analysis, the existing analyses for PBNP Units 1 and 2 loose parts envelopes the EPU conditions based on evaluation of pre-EPU and post-EPU conditions that affect wear due to a loose part. Therefore, the relevant parameters used in the original analysis, such as fluid velocity and vibration amplitudes, can also be used to address loose part wear occurring both before and after the EPU. Therefore, SG tube integrity is shown to meet the performance criteria of NEI 97-06, Revision 2 (Reference 10) during subsequent operation at EPU conditions.

Thus, the SG operation remains acceptable for two cycles between inspections when operating at the EPU conditions. This result satisfies the acceptance criteria.

Conclusions

Operation under EPU conditions does not increase the likelihood that loose parts will adversely affect steam generator tube integrity over two operating cycles, even when the limiting documented object remains within the steam generator secondary side.

2.2.2.5.9 Steam Generator Hardware Evaluation

Technical Evaluation

Introduction

The following steam generator tube-repair hardware items were evaluated for the PBNP Units 1 and 2 EPU:

- Shop-installed weld plug
- Ribbed mechanical plug
- Rolled mechanical plug
- Collared-cable stabilizers
- Bare cable stabilizers
- Tube-wall undercut

The structural evaluations of the above hardware items consider all specified loads that include: the normal (Level A) and abnormal-upset (Level B) load changes due to the EPU design transients specified in LR Section 2.2.6, NSSS Design Transients, and the Unit 1 Steam Generator Design Specification. In addition, the EPU results in an increased primary-to-secondary pressure differential of 1700 psi as discussed in Section 2.2.2.5.5, which is considered in lieu of the original 1550 psi design pressure differential. All hardware listed above is acceptable for EPU conditions based on ASME analyses and comparison of component test results to EPU conditions.

Input Parameters, Assumptions and Acceptance Criteria

Shop Installed Weld Plugs

There are six weld plugs in Steam Generator A at Unit 1 that were shop-installed during manufacture in the hot and cold legs of three tubes. The specific plug employed is the solid tapered design for the 0.875 inch outer diameter tubes used in the Model 44F steam generators. The shop-installed plugs and weld-rod-electrodes are both Alloy 600. The plugs are welded to the Alloy 600 tubes and the Alloy 600 tubesheet cladding. There are no shop-installed weld plugs in Unit 1 Steam Generator B or in the Unit 2 Steam Generators.

It is conservative to assume that the Alloy 600 plug welds have the same strength as the weaker 35 ksi minimum yield strength Alloy 600 SB-166 rod material given in Reference 14. As permitted by the Design Specification, the 1977 ASME Code (Reference 14) is used because Alloy 600 strength properties are not available in the 1965 ASME Code plus the summer 1966 Addenda (Reference 1).

The 1965 ASME Code does not address faulted conditions. Therefore, the assumed faulted condition direct shear stress allowable is $0.6(2.4S_m)$ per F-1323.1(b) of the ASME Boiler and Pressure Vessel Code, Section III, 1989 Edition through 1989 Addenda (Reference 17). This follows by analogy with the limits of NB-3227.2 of Reference 17.

In performing the fatigue analysis, the tabulated values of the fatigue design curve in the design specification are assumed to improve the accuracy of the calculations. The Alloy 600 fatigue design curves are essentially the same in References 14, 1, and 17.

It is conservative to assume that the minimum weld section of the tapered Alloy 600 shop-installed weld plug is loaded in direct shear by pressure forces, in which case the 13.98 ksi limit of Reference 1 applies.

Since Reference 1 does not contain limits for faulted conditions, the faulted allowable direct shear limit is taken to be 33.55 ksi from Reference 17.

If the six fatigue exemption conditions of Reference 1 are satisfied, an explicit calculation of the usage factor for the shop-installed weld plugs is not required.

Ribbed Mechanical Plug

The steam generators at Unit 1 contain SB-163 (Alloy 600) tubes that have 7/8-inch outer diameter by 0.050 inch average wall thickness. Two lengths of "ribbed" mechanical plugs are manufactured by Westinghouse for this size tube diameter. These two lengths of mechanical plugs have the same configuration in the tube contact region. The working-sealing land regions of both length plugs are identical. The structural evaluation presented herein covers both plug lengths. All earlier Alloy 600 plugs have been replaced, and all existing and future ribbed mechanical plugs are Alloy 690.

During installation, the mechanical plug lands are inelastically deformed by the expander, thereby producing radial contact pressure at the plug-tube interface that retains the plug. Since the limiting conditions for plug retention occur during tubesheet hole dilation due to tubesheet bowing from service loads, it is reasonable to assume that the resulting reduction (unloading) of contact pressure follows an elastic slope.

The strain at the tube to tubesheet interface produced by the mechanical plug should exceed the strain produced by the limiting transient trying to open (dilate) the interface.

The primary stress criteria of the ASME Code, Reference 17, for Design, Faulted and Test conditions apply.

Meeting the six fatigue exemption requirements in Section N-415.1 of Reference 1 will ensure that fatigue is adequately addressed for normal, upset, and test conditions.

The maximum external loading case for the plug shell (above the lands) is the secondary side hydrostatic test with the primary side at atmospheric (0 psig) and the secondary side between 120°F and 180°F, with the pressure at 1356 psig. This condition must meet the requirements of N-417.7 (Reference 17). Also, ASME Code requirements in Section NB-3226(c) (Reference 17) must be met. Specifically, the external pressure loading on the plug shell must be less than 80% of the lower bound collapse pressure considering the effects of yield strength (32.3 ksi at 180°F) and an assumed worst-case shell out-of-roundness of 2% of the outer diameter.

Rolled Mechanical Plug

Installation of the Westinghouse "rolled" mechanical plug employs a hard roller that plastically expands the plug inner surface and the host tube against the tubesheet-tube-hole near the primary face of the tubesheet. The mechanical plug is a hollow Alloy 690 cylinder with a closed end-cap. The steam generators at PBNP Unit 1 and 2 contain SB-163 Alloy 600 and Alloy 690 tubes, respectively, both of which have 7/8-inch outer diameter by 0.050-inch average wall thickness.

The major loadings are assumed to be the primary-to-secondary pressure differentials.

Based on the original test assumptions, the rolled mechanical tube plugs were tested at a primary pressure equal to, or greater than, the higher of 1.25 times the primary design pressure (1.25 × 2485 = 3106 psig), 1.5 times the highest accident pressure (1.5 × 2235 = 3353 psig, or three times the normal operating ΔP (3 × 1365 = 4095 psig). Since the latter criterion resulted in a higher pressure, 4100 psig was selected as the appropriate test pressure for qualification.

There are no normal operating conditions where the secondary pressure exceeds the primary pressure, therefore secondary (i.e., negative ΔP) test pressures were determined by the higher of 1.25 times the secondary design pressure (-1.25 × 1085 = -1356 psig) or 1.5 times the assumed normal operating secondary pressure (-1.5 × 870 = -1305 psig). Since the former criterion results in a higher pressure, ΔP = -1356 psig was chosen as the test pressure for the negative ΔP acceptance criterion.

Since the rolled mechanical plugs are located near the primary face of the tubesheet like the ribbed mechanical plugs and the shop-installed weld plugs, the six fatigue exemption requirements in Section N-415.1 of Reference 1 also apply and, if met, ensure that fatigue is adequately addressed for EPU normal, upset, and test conditions.

Collared-Cable Stabilizers

The Westinghouse collared-cable stabilizer design consists of a central coaxial cable made up of 302 SS wire strands protected over the full length of the stabilizer by several 304 SS tubular collars which are swaged onto the cable. The generic qualification of the stabilizers is directly applicable to the replacement steam generators at PBNP Units 1 and 2 under EPU conditions.

The qualification is based on potential relative wear between the inner surface of the host tube and the outer surface of the stabilizer collar. The wear tests suggest that both tube materials in the PBNP steam generators wear faster than the collar material. The degraded host tube containing the stabilizer is assumed to become fully severed and begin to whirl, forming a random wear couple between the severed host tube and the stabilizer collar.

It must be shown that the host tube wall wears away before the stabilizer collar, thereby protecting the central coaxial cable from wear for the life of the installation. Also, significant contact with adjacent tubes should not occur when the host tube wears out and becomes free to whirl.

Bare Cable Stabilizers

Westinghouse bare cable tube stabilizers are designed for installation in the PBNP Unit 1 Model 44F and Unit 2 Δ47 steam generators during upcoming outages.

Two cases are considered that bound all potential host tube locations in the Unit 1 Model 44F steam generators. Also, two cases are considered that bound all potential host tube locations in the Unit 2 Δ47 steam generators. For all cases, the stabilized tube is assumed fully severed at the secondary face of the tubesheet.

The internal stabilizer restrains the severed end of the host tube against displacement in all directions but is assumed to provide no rotational restraint. Sufficient restraint in the vertical direction is available through friction such that no vertical vibration needs to be considered, and the host tube would not lift off from the stabilizer, causing vertical movement.

Based on damping tests for severed, stabilized tubes, a critical damping ratio of 8.1% for the stability ratio calculation is assumed.

A conservative threshold instability coefficient of 3.0 is assumed.

The effective fluid velocity and density values over the critical mode shape span are assumed for the average fluid velocity and density values in the mid-span vibration amplitude calculation.

The stability ratio of a stabilized tube is equal to the effective velocity divided by the critical velocity (i.e. S.R. = V_{eff}/V_{CR}) and must be less than or equal to one.

The maximum turbulence displacement of the stabilized tube due to random turbulent excitation must be less than one-half the lateral gap between the tubes.

The maximum root-mean-squared (RMS) vibration amplitude, due to periodic wake shedding, is limited to 2% of the tube outer diameter (17.5 mils).

The tube peak stress, due to flow-induced vibration, shall be less than the endurance limit of 28.3 ksi per the fatigue curve (Figure I-9.2.1) of the ASME Code (References 1, 14 or 17) for the Alloy 600 tube material.

No contact between a severed/stabilized tube and any other tube may occur at the point of break.

The subject tube is restrained by the tube stabilizer such that the potential to produce a loose part in the steam generator is minimized.

Tube-Wall Undercut

There may be instances in which it is desired to return a plugged steam generator tube to service. The plug is removed by drilling or machining resulting in a local thinning at the bottom of the tubing (at the primary face of the tubesheet).

The value assumed for tubing undercut is a 40% cutback from the original minimum tubing thickness.

The unit cell modeling approach to simulate the tubesheet is assumed to assure sufficient tubesheet material is included in the finite element model so that boundary conditions are realistic.

The axial pressure load on the tubing is assumed to be totally carried by the tube-to-tubesheet weld. However, other analysis plus testing demonstrates that the tubing has high resistance to pullout due to the tubing installation method (hydraulic expansion) which is neglected here. This assumption provides a conservative analysis result for the structural evaluation of the tube-to-tubesheet weld remnant.

The full secondary pressure is applied at the exterior surface of the tubing within the elevations of the tubesheet.

Meeting the six fatigue exemption requirements in Section N-415.1 of Reference 1 will ensure that fatigue is adequately addressed for normal, upset, and test conditions.

The primary stress limits presented below apply to the tubing and weld material at the tube-to-tubesheet weld area. It was found the tubesheet base material has a comparatively lower stress that is not the limiting factor. While certain conditions (such as test loading) could have been evaluated with the use of higher allowables, instead, the lowest allowables were used for all loading cases. This provides enveloping of all the load conditions for the EPU. The allowables used for the evaluation are:

Shear stress limit = 15.96 ksi under operational conditions to 650°F

S_m stress limit = 26.6 ksi under operational conditions to 650°F

1.5 S_m stress limit = 39.9 ksi under operational conditions to 650°F

Description of Analyses and Evaluations

Shop Installed Weld Plugs

The weld attaching the solid bar shop-installed weld plug is primarily loaded in direct shear if the secondary side pressure P_s is greater than the primary side pressure P_p. Generally the opposite loading occurs, namely the primary side pressure is greater than the secondary side pressure ($P_p > P_s$) and most of the positive ΔP load is also taken in bearing at the tapered interface with the tube. However, it is conservatively assumed herein that the ΔP load is totally carried by the minimum weld section in direct shear regardless of the sign of ΔP.

The six fatigue exemption conditions in N-415.1 of Reference 1 were evaluated for the shop-installed weld plugs in lieu of an explicit calculation of the usage factor. The fatigue exemption evaluation considers the specified normal and upset EPU design transients. In evaluating the six fatigue exemption conditions, the material properties for Alloy 600 from Reference 14 are applied.

Ribbed Mechanical Plug

The approach is to assess the impact of the EPU design transient changes on the existing generic qualification of the ribbed mechanical plugs performed for the Model 44F steam generator. The first part of the evaluation includes the review for stress and plug retention qualification. The second part of the evaluation deals with fatigue exemption condition compliance.

Rolled Mechanical Plug

Testing demonstrates the capability of a Westinghouse rolled mechanical tube plug to meet the requirements associated with plugging tubes in the Units 1 and 2 steam generators. A comparison was performed of the test program parameters and the Units 1 and 2 EPU parameters.

Collared-Cable Stabilizers

The straight leg collar-cable-stabilizer qualification is based on geometric parameters and the relative wear coefficients between the stabilizer collars and the host tube materials. These are independent of the dynamic fluid forces causing potential random vibration of the assumed severed host tube. Thus, changes in fluid flow conditions due to EPU and tube support conditions are judged to have essentially no effect on the ultimate protective function of the collared-cable-stabilizer to prevent deleterious contact with adjacent tubes.

Bare Cable Stabilizers

Finite element analyses were performed to justify use of bare core stabilizers in PBNP Units 1 and 2 steam generators. EPU thermal-hydraulic data provided the secondary side fluid velocities, densities, and the void fractions for the analysis. The fluid elastic stability ratio, or the ratio of the effective velocity to the critical velocity (V_{eff}/VCR), the vibration amplitudes caused by turbulence, and the resulting dynamic forces and moments generated at the tube support locations are calculated for a given thermal-hydraulic input and tube support condition. Tube constraint boundary conditions include the tubesheet, the six (6) tube support plates above the tubesheet on both the hot and cold leg sides and the four (4) anti-vibration bars (AVBs), where applicable, in the U-bend region. The master degrees of freedom are selected to accurately develop the span modal displacements.

An equivalent tube density was developed that considers the tube material mass, the stabilizer material mass, fluid mass inside the tube and hydrodynamic virtual mass of fluid outside of the tube.

When tubes in a heat exchanger array are subjected to fluid cross flow, there is a threshold or critical cross flow velocity (V_{CR}) where the onset of fluid-elastic unstable vibrations occur. If the cross-flow velocity is not constant over a tube span, an effective velocity (V_{eff}) must be determined.

Tube-Wall Undercut

Fatigue was evaluated by demonstrating that the six fatigue exemption requirements in Section N-415.1 of Reference 1 are met.

For the shear stress evaluation, the maximum loading is determined and is used in evaluating the direct shear stress level. This is calculated by determining the minimum shear resisting area through the tube-to-tubesheet weld.

For the bending and other primary stress determinations, an axisymmetric finite element model was utilized that includes the tubing, clad material, weld material, and tubesheet material. A sufficient amount of tubesheet material is modeled such that model boundary conditions are realistic. The tubing is thinned by at least 40% compared to its minimum thickness value due to the machining operation and is modeled with a wall thickness of 0.025 inch. The outer diameter of the tubing and the inner diameter of the hole in the tubesheet were modeled at 0.893 inch.

Results

Shop Installed Weld Plug

The overall maximum direct shear stress in the minimum vertical throat section of the shop-installed weld plug is 5.75 ksi for the overall maximum specified primary-to-secondary pressure differential ΔP load of 3107 psig for the primary side hydrostatic pressure test, which is less than the 13.98 ksi ASME Code allowable for the specified design, upset, and test conditions.

Note that the faulted condition direct shear stress allowable of 33.55 ksi is much higher (than 13.98 ksi), and that the specified maximum faulted ΔP load (2485 psi for the steam pipe break) is actually less than the maximum test ΔP load (3107 psi). Thus, the faulted direct shear stress limit is also satisfied.

The ASME Code primary stress limits in Reference 1 for the shop-installed weld plug remain satisfied with positive margins for all maximum specified primary load conditions.

The six fatigue exemption conditions in N-415.1 of Reference 1 are satisfied for the shop-installed weld plugs. Thus, an explicit calculation of the usage factor for these weld plugs is not required. The fatigue exemption considers the specified normal and upset thermal transients for the EPU.

Ribbed Mechanical Plug

The primary stress summaries for PBNP Unit 1, based on PBNP specific code limits, are specified in Table 1 for the Alloy 690 plug material. These stresses meet ASME Code (Reference 17) allowables.

The six fatigue exemption conditions in N-415.1 of Reference 1 are satisfied for the Alloy 690 ribbed mechanical plugs. Thus, an explicit calculation of the usage factor for these plugs is not required. The fatigue exemption considers the specified normal and upset thermal transients for the EPU.

Rolled Mechanical Plug

The test pressure used in the original qualification tests varied from 4100 to 4500 psig. However, a provision was made during the original test program to verify the plugs could withstand even higher differential pressures. A detailed review of the data shows that eight tube plug samples were tested at ΔP pressures up to 10,000 psig with no failures. The intent of these tests was to increase the ΔP until the tube plug failed. However, the test equipment began to fail before the tube plug samples could be tested to failure. As a result, the tests were terminated at 10,000 psig. Based on these results, a Westinghouse roll expanded mechanical tube plug installed in the PBNP Units 1 and 2 steam generators has a factor of safety of at least six (10000/1649) for primary-to-secondary differential pressure loading.

For negative ΔP loading, a review of the test data shows that test secondary-to-primary pressure differentials varied from -1400 psig to -1450 psig. The secondary-to-primary differential a rolled mechanical tube plug would experience in the PBNP Units 1 and 2 steam generators would be no more than -1.25 times 1085 psia, or -1356 psia. Further review of the data shows that an additional 10 tube plugs were tested at high secondary pressures. No failures were noted until pressures reached at least ΔP = -4000 psig with some samples reaching -8000 psig. Although there was some movement of the tube plug at these pressures, no plug ejection occurred. Based on these results, Westinghouse roll expanded mechanical tube plugs installed in the PBNP Units 1 and 2 steam generators have a factor of safety of approximately three for secondary pressure.

Hence, the test program used to qualify the rolled mechanical tube plugs installed in the PBNP Units 1 and 2 steam generators remains valid for the EPU.

Collared-Cable Stabilizers

As stated above, the straight leg collar-cable-stabilizer qualification is based on geometric parameters and the relative wear coefficients between the stabilizer collars and the host tube materials. These are independent of the dynamic fluid forces causing potential random vibration of the assumed severed host tube. Thus, changes in fluid flow conditions due to EPU and tube support conditions are judged to have essentially no effect on the ultimate protective function of the collared-cable-stabilizer to prevent deleterious contact with adjacent tubes.

Bare Cable Stabilizer

The overall most limiting maximum calculated fluid-elastic stability ratio is 0.448. Therefore, the stabilized tube with a straight leg bare cable type tube stabilizer will remain fluid-elastically stable under EPU conditions since the stability ratio for the credible tube support conditions is less than one.

The overall calculated maximum root-mean-squared (RMS) vibration amplitude, due to periodic wake shedding, is less than ½ mil, which is well within the 2% tube OD limit of 17.5 mils.

The maximum turbulence amplitude or midspan root-mean-square (RMS) displacement is 1.90 mils. This value is less than half the gap distance between tubes of 180 mils for the turbulence-induced vibration analysis.

The overall maximum peak turbulence-induced bending stresses on the stabilized tubes in Unit 1 is less than ½ ksi, well below the endurance limit of 28.3 ksi for the tube. Consequently, the contribution of the EPU to additional fatigue usage is negligible, and fatigue degradation from flow-induced vibration in a stabilized tube is not anticipated.

Tube Wall Undercut

The overall maximum direct shear stress at the tube-to-tubesheet weld (with the tube-wall undercut geometry) is 10.88 ksi for the maximum specified primary-to-secondary pressure differential load of 2485 psig for the primary side hydrostatic pressure test. This value is less than the 15.96 ksi ASME Code shear allowable. This primary side hydrostatic pressure test provides the maximum load of all plant conditions. Thus, the use of the largest load and the lowest allowable value provides an overall enveloping result for the shear stress evaluation.

The tubing and tube-to-tubesheet weld are also subjected to biaxial stress loading from the various pressure cases. For analysis purposes, the two largest pressure ΔP loads were evaluated. The maximum loading cases are 2485 psig pressure loading on the primary side of the tubesheet and, for the second case; the loading is 1356 psig for loading from the secondary side. These loads represent the primary and secondary hydrostatic testing cases respectively.

The maximum stress intensity occurs with the loading above for the first of the two cases, the primary side hydrostatic loading. The maximum values are found to be 24.2 ksi for the membrane stress and 27.3 ksi for the membrane plus bending stress. Of all the plant operating conditions, the lowest allowables are 26.6 ksi for membrane and 39.9 ksi for membrane plus bending. In the same manner that the shear stress is evaluated with maximum loads and minimum allowables, the stress intensity evaluation is also able to utilize this approach and, thus, envelopes all loading cases. It is found that the stress intensity values due to the primary loading cases are satisfied relative to the ASME limits for all specified loads under EPU conditions.

Evaluations have shown that the six fatigue exemption conditions in N-415.1 of Reference 1 are satisfied for the tube-wall undercut area. Thus, an explicit calculation of the usage factor for this area is not required. The fatigue exemption considers the specified normal and upset thermal transients for the EPU.

Conclusions

Shop-Installed Weld Plug

The shop-installed weld plugs satisfy all ASME Code structural limits in Reference 1 and remain qualified for use in the Unit 1 Model 44F Steam Generator A for the EPU. There are no shop-installed weld plugs in steam generator B of Unit 1 or the SGs in Unit 2.

Ribbed Mechanical Plug

The Westinghouse ribbed mechanical plugs satisfy all ASME Code structural limits in Reference 1 and remain qualified for use in the PBNP Unit 1 Model 44F Steam Generators for the EPU.

Rolled Mechanical Plug

The test program used to qualify the rolled mechanical tube plugs remains valid for use of the plugs in the PBNP Units 1 and 2 steam generators under EPU conditions.

Collared-Cable Stabilizers

The Westinghouse collared-cable stabilizers remain qualified for use in PBNP Units 1 and 2 steam generators under EPU conditions.

Bare Cable Stabilizers

The Westinghouse straight leg bare cable stabilizers remain qualified for use in fully degraded and severed host tubes in either the PBNP Unit 1 Model 44F or Unit 2 Δ47 steam generators for the maximum flow induced vibration loading due to the EPU.

Tube-Wall Undercut

The tube-wall undercut area satisfies all ASME Code structural limits and is thus qualified for use in the PBNP Unit 1 Model 44F Steam Generators for the EPU. No hardware that would be associated with a tube undercut is installed in the Unit 2 steam generators.

2.2.2.5.10 Steam Drum Component Evaluation

Technical Evaluation

Introduction

An assessment has been performed to determine the impact of the EPU on the steam drum components in the Model 44F steam generators (SGs) at Unit 1 and the Δ47 SGs at Unit 2. This report section provides:

1. A general description of steam drum components
2. A summary of field inspection results of the steam drum region within the PBNP Unit 1 and Unit 2 steam generators as well as in identical or similar model Westinghouse SGs at other plants
3. Assessment of EPU effects on degradation mechanisms that could be relevant to steam drum components of the PBNP Unit 1 and Unit 2 SGs

General Operation of the SG

The vertically-oriented original Westinghouse Model 44 steam generators at PBNP Units 1 and 2 were designed in accordance with the 1965 Edition through the Summer of 1966 Addenda of the ASME Code (Reference 1) for operation in a closed cycle pressurized light water nuclear power plant. The vertically-oriented replacement Westinghouse Model 44F and Δ47 SGs at PBNP Units 1 and 2, respectively, were also designed and certified in accordance with the 1965 Edition, through Summer 1966 Addenda. Later ASME Codes were used for materials that were not included in the 1965 ASME Code edition, through Summer 1966 Addenda; The ASME Code 1977 Edition through Winter 1978 Addenda (Reference 14), and ASME Code 1986 Edition (Reference 15), for Units 1 and 2 respectively. These SGs use high temperature pressurized water on the primary side as the heat source for producing essentially dry, saturated steam on the secondary side. During normal steady-state operation, the liquid inventory on the secondary side is maintained by the balanced addition of feedwater through an internal feedwater piping header. The addition of cooler secondary-side water within the SG forces the steam water mixture to rise within the vessel and eventually reach the steam drum. This wet steam mixture then passes through two moisture separation stages within the steam drum to mechanically remove water and produce essentially dry steam for the downstream turbine-generator.

Steam Drum Operating Principles

Various components introduce and direct the flow of steam and water in the steam drum. The feedwater ring is an internal piping assembly that delivers water to the secondary side of the SG. The lower deck plate provides physical separation between the tube bundle region of the SG and the steam drum region. The mid-deck plate serves as the physical barrier between the "wet" steam environment below and the drier steam environment above after the first stage of moisture separation.

The steam drum contains special equipment to remove water from the water/steam mixture exiting the top of the tube bundle. The liquid-to-vapor phase of the water/steam mixture produced within the tube bundle occurs just above the top of the tube bundle, but below the first stage of moisture separating equipment. The first stage of equipment for separating water from the water/steam mixture is the primary moisture separators. The "wet" steam enters the primary separators and is forced through swirl vane blades. The stationary swirl vane blades cause the vertical linear velocity of the "wet" steam to be converted into a rotary (i.e., circular) velocity, creating a centrifugal acceleration. The heavier water droplets within the "wet" steam collect along the inner surface of the barrel wall of the primary separator by centrifugal force. Eventually these droplets travel down the surrounding downcomer barrel to be returned to the liquid inventory. The remaining "dry" steam exits the top of the primary separator through an orifice to continue to the second stage of moisture separation.

The second stage of equipment for separating water from the water/steam mixture is the secondary moisture separator assembly. This equipment operates on the principle that a change in flow (momentum) direction will remove additional water droplets from the steam/water mixture. The secondary separator assembly employs various surfaces to create a tortuous flow path for the water/steam mixture to create dry steam.

Input Parameters, Assumptions and Acceptance Criteria

Plant thermal-hydraulic inputs considered in this assessment of the performance of the steam drum components in the Model 44F and Δ47 SGs during normal and EPU plant operating conditions are as described LR Section 1.1, Nuclear Steam Supply System Parameters.

PBNP Units 1 and 2 specific field inspection data considered in this assessment of the performance of the steam drum components are based upon inspections conducted at various times since March 1998.

Steam drum component field inspection data from other operating plants with identical or similar model Westinghouse SGs are used.

The relevant acceptance criteria for the assessments are as follows:

- Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the thermal performance or moisture separation function of the affected component.
- Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the structural integrity of the component.
- Degradation, if found to exist in any steam drum component, will not create a loose part that will adversely impact or compromise the safe operation of the plant.

Description of Analyses and Evaluations

In this section, a summary explanation of the field inspection data of the steam drum components in the Model 44F and Δ47 SGs at PBNP Units 1 and 2, respectively, is provided. Likewise, field inspection data of steam drum components in identical or similar models of Westinghouse SGs is summarized to provide a comparison of PBNP SGs to industry experience inspection results.

PBNP-Specific Steam Drum Inspection Experience

No anomalies were reported following inspection of the steam drum region of SG B of Unit 1 in March 1998, although slight evidence exists of loss of magnetite at the junction between the swirl vane blade and the primary riser barrel wall. The same visual inspection was performed on SG A and SG B in Unit 2 in December 1996 during the steam generator replacement outage and prior to service. No anomalies were reported during the inspection.

The most recent visual inspections of the steam drum regions were performed during U1R30 (April 2007), U2R29 (April 2008), and U1R31 (Fall 2008) outages.

During the U1R30 inspection, flow impingement patterns were noted on the OD surface of the feedwater ring in SG A. Visually, no loss of feedring wall thickness was detected. In addition, scouring patterns caused by J-nozzle discharge were also noted on the OD surface of several primary separators. It was noted that one of the perforated plate assemblies on Bank "E" in SG A was warped, creating an offset of approximately 0.25-inch relative to the adjacent perforated plate. A similar condition was reported during the inspection of SG B with the offset approximately 9/16-inch. Another observation noted evidence of "rust" on several swirl vane blades in a number of primary moisture separator assemblies in SG A. The presence of rust indicates that the protective magnetite coating has been removed, exposing the base metal (carbon steel). Visual inspection performed on the ID of the feedwater rings in both SGs noted several J-nozzles with "burn-through," apparently caused during the field installation of the Alloy 600 J-nozzles. No additional anomalies were detected, and the remaining components observed were reported to be in good condition.

During the U2R29 outage, visual inspection revealed no anomalies within either the feedwater rings or the primary moisture separators. No anomalies were expected since these components have been fabricated from materials which are inherently resistant to flow accelerated corrosion (FAC). No anomalies were reported in any other components inspected during U2R29.

During the fall 2008 outage at PBNP Unit 1, visual inspections were performed on steam generator (SG) carbon steel components in the separator/dryer area. In addition, ultrasonic testing (UT) was performed on SG components including selected primary separators and feedrings. No significant visual or measured indications of erosion/corrosion were observed. This data will be used as part of the benchmark for post-EPU inspections.

Industry-Related Steam Drum Field Inspection Data for Westinghouse Model SGs

Steam generator inspections have included examination of the secondary moisture separators, mid-deck plate (primary separator discharge end), downcomer barrels, tangential nozzles, under side of the intermediate deck plate, primary separator OD, feedwater ring, feedwater nozzle and SG shell. Inspections included SG Models 44, 51, 51F, D4, D5, F and delta 75. Conditions such as scouring and material loss due to erosion/corrosion (including reduction of wall thickness and through-wall holes in various locations) have been found.

Assessment - Specific Steam Drum Components

An assessment was performed to evaluate the impact of increased EPU water/steam flow would have on carbon steel components of the steam drum region. Fluid velocities were calculated specifically for PBNP for current operating conditions and for EPU conditions. These flow velocities were then compared to flow velocities in other SG models where degradation (i.e., FAC or erosion/corrosion) has been observed. It was concluded that flow velocities in the PBNP SGs would equal or exceed the flow velocities in SGs exhibiting degradation and, therefore, the carbon steel components in the steam drums of the Unit 1 SGs may be susceptible to future material degradation at uprated plant operating conditions. Erosion-corrosion of steam drum components is also a function of chemistry conditions. Chemistry is discussed in LR Section 2.2.2.5.11.

2.2.2.5.10.1 Results

Assessment of the steam drum components of Unit 1 SGs relative to the criteria provided above produced the following results. The Unit 2 steam generators' steam drum components are fabricated of corrosion/erosion resistant material and, therefore, are not considered to require evaluation.

Thermal-Hydraulic Performance

Criterion: Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the thermal performance or moisture separation function of the affected component.

Minor erosion-corrosion conditions on the OD surface of the feedwater ring and adjacent primary separators and evidence of "rust" on the swirl vane blades in some of the Unit 1 primary separators have been reported. However, no adverse conditions with respect to any other steam drum components have been reported and, therefore, all steam drum components are believed to be intact and in good operating condition. Hence, it is expected that these components will maintain the thermal-hydraulic performance of the SG steam drum region within the originally specified design requirements, as well as within the originally specified design conditions.

Industry experience on similar steam drum component structures in other plants does, however, indicates that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25% of the original wall thickness, and 50% in isolated spots. A worst-case scenario would be through-wall holes in these structures.

Based on industry data, the potential exists that the steam drum structures in the PBNP Unit 1 SGs may experience similar degradation under current operating conditions. If the steam drum components experience similar degradation to that recently found in other plants, even with a reduced wall thickness, these structures could still maintain the thermal-hydraulic conditions within the originally specified design requirements. Therefore, the thermal performance and moisture separation function of the SG should also be maintained within the originally specified design conditions.

With the increased flow conditions within the steam drum expected from EPU conditions, material loss in the carbon steel steam drum components may be initiated or accelerated. Periodic steam generator inspections will detect degradation that may occur.

Structural Adequacy

Criterion: Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the structural integrity of the component.

Minor erosion-corrosion conditions on the OD surface of the feedwater ring and adjacent primary separators and evidence of rust on the swirl vane blades in some of the Unit 1 primary separators have been reported. However, no adverse conditions with respect to any other steam drum components have been reported and, therefore, all steam drum components are believed to be intact and in good operating condition. Hence, it is expected that these components will maintain the thermal-hydraulic performance of the SG steam drum region within the originally specified design requirements, as well as within the originally specified design conditions.

Industry experience on similar steam drum component structures in other plants does, however, indicate that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25% of the original wall thickness, and 50% in isolated spots. A worst-case scenario would be through-wall holes in these structures.

Based on industry data, the potential exists that the steam drum structures in the PBNP Unit 1 SGs may experience similar degradation under current or EPU operating conditions. If the steam drum components experience similar degradation as recently found to exist in other plants, the degradation will have a negligible impact upon the structural adequacy of the steam drum components affected. Most material loss observed in other plants thus far has been in specific localized areas that do not have significant applied loadings. The amount of observed material loss in these other plants is not currently considered to be significant with respect to the major load conditions (e.g., steamline break, seismic). The loads used to originally qualify the steam drum components were the design basis event (DBE) seismic event combined with blowdown loads from a secondary coolant line break. These loads conditions will not change significantly under EPU conditions and, therefore, will not have an effect of the original analysis. Furthermore, flow-induced vibration of these components during uprated conditions is considered to be enveloped by the original design basis evaluations due to the limited change in flow parameters within the steam drum under EPU conditions. Prior analysis performed for SGs with more significant erosion indicates that large margins are typically present for erosion of this type when occurring at these specific locations. As a result of the observed levels of material loss and prior analysis performed for other model SGs, it is expected that any operational loads imposed upon these components considering further erosion potential will not adversely impact or compromise their structural integrity.

With the increased flow conditions within the steam drum expected from EPU conditions, material loss in the carbon steel steam drum components may be initiated or accelerated. Periodic steam generator inspections will detect degradation that may occur.

Loose Parts

Criterion: Degradation, if found to exist in any steam drum component, will not create a loose part that will adversely impact or compromise the safe operation of the plant.

Minor erosion-corrosion conditions on the OD surface of the feedwater ring and adjacent primary separators and evidence of rust on the swirl vane blades in some of the Unit 1 primary separators have been reported. However, no adverse conditions with respect to any other steam drum components have been reported and, therefore, all steam drum components are believed to be intact and in good operating condition. Hence, it is expected that these components will maintain their integrity and not generate loose parts.

Industry experience on similar steam drum component structures in other plants does, however, indicate that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25% of the original wall thickness, and 50% in isolated spots. A worst-case scenario would be through-wall holes in these structures.

Based on industry data, the potential exists that the steam drum structures in the Unit 1 SGs may experience similar degradation under current operating conditions. The steam drum components which could potentially have erosion-corrosion degradation are non-nuclear safety class parts. As noted in Section 3.3.1.4 of ANSI-51.1-1983, the design of non-nuclear safety class equipment must resist failure that could prevent safety class equipment from performing its nuclear safety function. In the case of potential erosion-corrosion of the steam drum components, the most significant condition, from a plant safety perspective, would be the potential for generating a loose part and subsequent impacting and sliding wear on the SG tubes.

If degradation does exist in the steam drum components in the PBNP Unit 1 SGs in a manner similar to that experienced in other plants, based on the geometry of the components, such degradation will have a negligible impact upon the structural adequacy of the steam drum components affected. If continued wall loss were to cause thinned areas to connect, the fragment(s) generated would not be expected to be of sufficient size to wear a tube to the minimum allowable wall thickness during one operating cycle. Routine visual examinations on the secondary side of the tubesheet have successfully detected and retrieved foreign objects before safe operation has been compromised. Moreover, in the unlikely event that a loose part should come in contact with an SG tube during subsequent plant operation, the consequences of impacting and sliding wear on a tube by the loose part would be bounded by the accident analysis for a single tube rupture event.

If a foreign object were generated in the steam drum region, the potential for it to exit the SG and enter the main steam or main feedwater systems is negligible based on the following:

- For an object to exit the SG and enter the main steam system, it must pass through the secondary moisture separator's perforated plates and chevron vanes as well as the main steam venturi nozzles, all while overcoming the effects of gravity. An object capable of passing through this tortuous path would be of negligible size.

- An object would not be expected to enter the main feedwater system due to the design of the feedwater ring. The forward flow of feedwater through the J-nozzles would preclude an object from entering this system during plant startup and power operations.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached for the evaluation of the Steam Generator as part of the Steam and Power Conversion Systems in Section 3.4 of the PBNP License Renewal SER. PBNP has concluded that the existing aging management evaluations remain valid following implementation of the EPU.

Conclusions

Inspection results have been evaluated for the steam drum components in the Model 44F SGs at Unit 1 and the Δ47 SGs at Unit 2 and for the same or similar SGs at other plants. Results of these evaluations and ongoing, periodic inspections of the PBNP Units 1 and 2 SGs ensure acceptable operation of the SGs under EPU conditions.

2.2.2.5.11 Steam Generator Chemistry Evaluation

Technical Evaluation

Introduction

Water chemistry of both the primary and secondary sides in nuclear power plants is controlled to maximize the long-term availability of pressurized water reactor (PWR) plants. Primary water chemistry control can, and has been, effectively used to control radiation field buildup on ex-core surfaces also. Guidelines have been provided to utilities by the Electric Power Research Institute (EPRI) for primary and secondary chemistry (References 2 and 3). In addition, other organizations such as the Nuclear Energy Institute (NEI) have provided guidelines with respect to specific equipment (e.g., steam generators) which are incorporated into the EPRI guidelines. These documents form an industry consensus approach for chemistry programs which are embodied in and augmented by the plant-specific strategic water chemistry plans for the primary and secondary systems (References 4 and 5). Plant-specific strategies must consider plant design, ability to support chemistry control philosophies and targets, and cost-benefit trade-offs.

Uprates in power potentially affect water chemistry in the steam generator of the nuclear power plant because of changes in temperature and/or flow rates. This document provides a generic evaluation of previous chemistry history or detailed review of chemistry procedures.

Input Parameters, Assumptions and Acceptance Criteria

Input parameters include the operational parameters provided in the LR Section 1.1, NSSS Parameters, EPRI primary and secondary chemistry guidelines (References 2 and 3), PBNP strategic water chemistry optimization plans for the primary and secondary sides (References 4 and 5), and the primary and secondary chemistry monitoring programs for PBNP (References 6 and 7).

The strategic water chemistry plans for both the primary system chemistry and the secondary system chemistry are based on EPRI guidelines. The PBNP chemistry monitoring program is also based on those guidelines.

The PBNP secondary strategic water chemistry optimization plan discusses a number of initiatives currently contained in the secondary water chemistry monitoring program (Reference 6). These include:

- ALARA chemistry
- Hydrazine program
- pH and corrosion product control
- Wet layup chemistry - Steam generators
- Wet layup chemistry - Feedwater system
- Use of Boric acid as secondary side IGA/SCC inhibitor

Exceptions from EPRI PWR Secondary Water Chemistry Guidelines are also discussed.

The PBNP primary strategic water chemistry optimization plan discusses a number of initiatives currently contained in the primary water chemistry monitoring program (Reference 7) and provides a history of the current plan content. These initiatives include:

- pH program
- Dissolved oxygen control
- Hydrogen control
- Chloride/fluoride/sulfate control
- Silica shutdown chemistry
- Start-up chemistry practices

Core design and its effect and chemistry changes that effect fuel integrity are also discussed.

PBNP will continue to control the primary and secondary chemistry in accordance with the strategic optimization plans in References 4 and 5 and the monitoring programs presented in References 6 and 7.

Acceptance Criteria

No specific changes in chemistry of either the primary or the secondary side are expected due to the EPU because the chemistry will continue to be controlled after the upgrade by plant procedures and specifications conforming to industry accepted guidelines and embodied in the PBNP strategic water chemistry guidelines.

Description of Analyses and Evaluations

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP Water Chemistry Control Program is credited for controlling degradation of both primary and secondary portions of SG components for License Renewal. The EPU activities do not add any new components nor do they introduce any new functions for existing components that would degrade the effectiveness of the Water Chemistry Control Program. Therefore, the effects of the EPU do not impact the conclusions of the License Renewal SER.

EPRI guidelines recognize the difference in design and operating characteristics of nuclear plants and prescribes that each plant generate strategic water chemistry plans for the primary and secondary water chemistries. This allows chemistry programs specifically tailored for each plant. References 4 and 5 provide those strategic plans for PBNP.

Results

PBNP chemistry is controlled based upon strategies contained in its primary and secondary strategic chemistry optimization plans and implemented through the primary and secondary water chemistry monitoring programs.

Conclusions

No significant changes in the bulk chemistry of either the primary or secondary side are expected due to the uprating because the bulk chemistry will continue to be controlled after the upgrade by plant procedures and specifications conforming to industry accepted guidelines and embodied in the PBNP strategic water chemistry plans and the chemistry monitoring programs.

In addition, the temperatures stated in LR Section 1.1, NSSS Parameters, are in the range where other plants control bulk chemistry based on the same industry guidelines. The PBNP secondary water guidelines address possible concerns about chemical species accumulation and deleterious effects.

2.2.2.5.12 Regulatory Guide 1.20 Evaluation - Vibration Assessment Program for Reactor Internals

Technical Evaluation

Introduction

Regulatory Guide (RG) 1.20 (Reference 9) provides specific examples of SG internals and indicates that both past operating experience and analysis may be used to support the determination of adequate design margin for the stresses on PWR SG internal components.

The analysis and evaluation performed for PBNP Unit 1 and 2 SGs for RG 1.20 Reference 21) compliance takes into account operating experience, comparative evaluations, and analytical results. This information and these analytical methods are combined to develop overall conclusions regarding potential adverse effects of acoustic resonances and flow-induced vibrations on the PBNP Units 1 and 2 SG steam dryer components. Figure 2.2.2.5-1 is a diagram of the PBNP Units 1 and 2 SG two tier steam dryer design. The conclusions developed follow the RG 1.20 guidelines and evaluation methodology, and provide a comprehensive vibration assessment of the potential adverse effects of operating the Units 1 and 2 Westinghouse Model 44F and Δ47 two tier SG steam dryer components at EPU conditions.

Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

- PBNP Units 1 and 2 SGs operate at EPU conditions
- The planned moisture carryover (MCO) SG modifications for PBNP Units 1 and 2 have been successfully implemented

Acceptance Criteria

Any acoustic or flow-induced vibration potential will not compromise the continued safe operation of the PBNP Units 1 and 2 SGs at the EPU conditions.

Description of Analyses and Evaluation

The method of analysis and evaluation addresses the following three areas:

- Historical operating experience
- Comparative evaluation
- Modal vibration analysis of the PBNP Model 44F SG two tiered steam dryers

These methods together represent the manner in which RG 1.20 (Reference 21) compliance is demonstrated for PBNP. These methods are briefly described in the following LR sections.

History and Operating Experience Review Method

This method consists of a comprehensive review of historical pressurized water reactor issues including responses to NRC requests for additional information on power uprate projects similar to the PBNP EPU. The review also covers open literature, industry papers, Units 1 and 2 SG inspection records, and NRC documentation related to steam dryer vibration issues potentially relevant to this evaluation. Conclusions using this method will be focused on the relation of both industry experience and historical issues to the particular design of the PBNP Units 1 and 2 Model 44F and Δ47 two tier steam dryer banks under extended power uprate operating conditions.

Steam Dryer Acoustic Pressure Wave Comparative Assessment

The Unit 1 and 2 dryers and their supports will experience increased flow under EPU conditions. The assessment uses available literature to compare the PNPB Unit 1 and 2 dryer bank and support structure geometry to boiling water reactor (BWR) dryers and supports that experienced vibration issues as described in RG 1.20. Conclusions of this method focus on geometry and support structure differences and discuss the effect of these differences on the acoustic pressure-loading induced vibration potential of the PBNP Units 1 and 2 dryer bank assemblies.

Natural Frequency and Modal Analysis Method

This method takes an analytical approach to evaluating the vibration potential of the Units 1 and 2 SG steam dryer bank assemblies. Finite element analysis (FEA) has been used to determine the natural frequencies and resulting mode shapes of the three-dimensional dryer bank assemblies. Classical vibration analysis relationships are then used to scope the deformation, stresses, and fatigue failure potential resulting from dryer bank assembly vibration at the critical mode shapes. This analytical method assumes that the dryer bank assembly will vibrate at a natural frequency. This analytical method has evaluated whether a dryer bank assembly seeing significant vibratory excitation will compromise the structural condition of the SG dryer bank support structure.

Results

The results for each of the three methods discussed above are as follows:

- Historical Review - Plant operation of the Units 1 and 2 SGs, with the two tiered steam dryer equipment, shows no indication of flow or acoustical type vibration issues.
- Evaluative Comparison - The comparative assessment performed shows that the geometrical differences in BWR designs, having experienced acoustic type vibration concerns, and the Units 1 and 2 Westinghouse Model 44F and Δ47 SG steam dryer components are substantial. A basis has been provided for concluding that acoustic type vibration is either unlikely to occur or inconsequential in this region of the steam generators.
- Vibration Analysis - Basic FEA methods of vibration analysis show that the steam dryer structures at both units have relatively high natural frequencies based on their rigid structure and relatively modest loadings. The stresses resulting from vibration are well below the fatigue endurance limit of the dryer bank material. Therefore, the steam dryer and support structure are determined not to be susceptible to vibrational fatigue failure and loose part generation.

Based on a strong historical database of issue-free operation, evaluated differences in steam dryer design type, analytically insignificant vibration potential and corresponding stress levels it is concluded that there are no significant vibration issues identified for operating the Units 1 and 2 SG steam dryer bank assemblies at EPU conditions.

Regulatory Guide 1.20 Evaluation Conclusions

The overall conclusions of the analysis qualitatively consider each of the three methods discussed (historical, evaluative, and analytical) to identify the flow and acoustic type vibration potential of the steam dyer bank assemblies and any impending detrimental structural effects on the steam dryer components. These methods are consistent with the requirements of Regulatory Guide 1.20, which recommends a review of past PWR operating experience of SG internal components as a minimum.

Based on a strong historical database of issue-free operation, evaluated differences in steam dryer design type, implementation of proposed mid-deck and secondary separator modifications to address MCO, and analytically insignificant vibration parameter and stress results, it is *concluded that there are no predicted vibrational issues identified for operating the Units 1 and 2* SG steam dryer bank assemblies at EPU conditions.

2.2.2.5.13 Structural Evaluation of Increased Primary-to-Secondary Pressure Differential

Technical Evaluation

Introduction

As determined in Section 2.2.2.5.5, the EPU increases the steam generator primary-to-secondary design pressure differential from 1550 psi to 1700 psi. The ASME Code structural evaluation of the Model 44F (Unit 1) and Δ47 (Unit 2) replacement steam generators' tubesheets, channel heads, and lower cylinders was performed based on a secondary pressure of 785 psig. This pressure corresponds to the increased design ΔP of 1700 psi acting coincident with the maximum primary side design pressure of 2485 psig.

Input Parameters, Assumptions, and Acceptance Criteria

The tubesheet, channel head, and cylinder were conservatively simulated using an axisymmetric finite element (FE) model to calculate the ΔP pressure stresses. Elements of FE evaluation included the following key assumptions, inputs, and acceptance criteria:

The structural evaluation was performed at the primary side design temperature of 650°F and primary-to-secondary side ΔP of 1700 psi. Although the tubes act to stiffen the tubesheet and increase the effective minimum ligament, the stiffening effect on the tubesheet holes was conservatively neglected. The effect of secondary pressure, in the interfaces between the tubes and tubesheet (assuming a tube mouth seal), was also conservatively neglected. The dead weight and seismic loads were assumed to be negligible when compared to the pressure stresses since they result in relatively small additional stresses in the tubesheet, channel head, and cylinder.

The elastic stiffness of the perforated region of the tubesheet was evaluated using effective elastic constants (E^* and μ^*), determined from the effective bending curves of Reference 12. This was determined to be an accepted state-of-the-art practice for performing perforated plate analysis (Reference 11, refer to appendices). The pressure stress intensity (P_m) allowable (S_m^*) *for the perforated region of the tubesheet was assumed to be the solid tubesheet material* allowable reduced by the ligament efficiency, which is consistent with the accepted practice in the ASME Code appendices (e.g., Article A-8142 of Reference 11). The pressure membrane-plus-bending stress intensity allowable (1.5 S_m^*) for the perforated region of the tubesheet was similarly calculated but included the biaxiality ratio factor, K, (Figure A-8142-1 of Reference 11), consistent with accepted practice in the ASME Code Appendices (e.g., Equation 18 of Article A-8142 in Reference 11).

Both elastic and elastic-plastic acceptance criteria were defined. The elastic stresses calculated in Cases 1 and 2 were evaluated to the primary membrane, primary membrane plus bending, and primary membrane plus secondary bending structural criteria given in the ASME Code (Reference 1). *The ASME Code acceptance criterion for the Case 3 FE model required the* specified differential pressure loading (ΔP = 1700 psi) not to exceed two-thirds of the lower bound limit (collapse) ΔP loading.

Description of Analyses and Evaluations

The pressure stresses in the Unit 1 Model 44F SG and the Unit 2 Δ47 SG tubesheet, channel head, and cylinder were calculated using finite element (FE) methods. A conservative axisymmetric model (without the divider plate) was assumed (See Figure 2.2.2.5-2). Due to the outcome of stress results (see Tables 2.2.2.5-4 and 2.2.2.5-5), the analysis approach required three different FE models for each unit to be used in order to demonstrate full ASME Code compliance:

Case 1: Elastic model

Case 2: Elastic model with pin connection between tubesheet and channel head

Case 3: Elastic-perfectly plastic model

The more conservative elastic stresses calculated in Cases 1 and 2 were evaluated against the structural criteria given in the 1965 Edition of Section III of the ASME Code (Reference 1). The pressure stress intensity and membrane-plus-bending allowables for the perforated region of the tubesheet included the ligament efficiency reduction (and the biaxiality stress factor K, for the membrane-plus-bending case). This is consistent with the ASME Code guidelines for perforated plates.

As permitted by later editions of Section III of the ASME Code (e.g., Reference 11) the aforementioned elastic limits (P_m and $P_m + P_b$) do not need to be satisfied if the specified loadings (i.e.,ΔP = 1700 psi) remain below two-thirds of the lower bound collapse load. As noted in the results section that follows, not all of the analyzed locations met the ASME Code acceptance criteria on a fully elastic basis. Thus, the less conservative Case 3 FE model approach was used to cover these discreet locations. For the Case 3 FE model, all materials were simulated as elastic-perfectly plastic with a pseudo "yield" strength set to 1.5 S_m in order to perform the lower bound limit-load analysis.

Results

Elastic stress results for Cases 1 and 2 are provided in Tables 2.2.2.5-4 and 2.2.2.5-5. For both units, the Case 1 stress ratios are generally less than one (indicating compliance with the ASME Code limit). The Section A1-A1, Case 2 FE model stress ratios remained greater than 1.0 for both units, therefore use of the Case 3 FE model was required.

The elastic-perfectly plastic results for Case 3 (not shown) predicted a lower limit primary-to-secondary pressure differential of 4700 psi for Unit 1 and 4970 psi for Unit 2. The allowable differential pressures, being two-thirds of these values (3100 psi for Unit 1 and 3300 psi for Unit 2) were well above the actual design primary-to-secondary ΔP of 1700 psi. Thus, the ASME Code Section III acceptance criteria were satisfied for both units at the tubesheet, channel head, and cylinder locations.

Conclusions

The results of the EPU evaluation demonstrate that the SG Tubesheet, Channel Head and Cylinder continue to comply with the structural criteria of the ASME Code Section III, Subsection NB. The tubesheet, channel head, and cylinder meet ASME Code limits for the increased primary-to-secondary pressure differential of 1700 psi. The differential pressure loading did not exceed two-thirds of the lower bound limit (collapse) ΔP loading.

2.2.2.5.14 Steam Generator Supports

Technical Evaluation

Introduction

The primary equipment steam generator supports of the nuclear steam supply system (NSSS) as described in FSAR Sections 4.1,Reactor Coolant System, Design Basis, FSAR Section 4.2, RCS System Design and Operation, FSAR Section 4.4, Tests and Inspection, and Appendix A.5 are evaluated for the EPU program. The reactor coolant loop (RCL) piping loads on the primary equipment steam generator supports due to the parameters associated with the EPU as discussed in LR Section 2.2.2.1, NSSS Piping, Components and Supports, are reviewed for impact on the existing RCL primary equipment steam generator supports design. The RCL piping loads on the steam generator supports are obtained from the evaluation for the EPU program as described in LR Section 2.2.2.1, NSSS Piping Components and Supports.

The steam generator supports stress margin values are evaluated for the EPU conditions based on the stress margin data from the current design basis and the steam generator support loads obtained from the evaluation for the EPU program from the RCL piping system analyses as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports.

Input Parameters, Assumptions, and Acceptance Criteria

The evaluation uses all criteria and methods in the existing design basis for PBNP.

The RCL piping loads on the steam generator supports due to deadweight (DW), thermal (TH) expansion, seismic design basis earthquake (DBE) and loss-of-coolant accident (LOCA) loading cases are obtained from the piping system analyses for the EPU as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports. Operational basis earthquake (OBE) loads are also included in the support evaluation. The steam generator support assessment consisted of reviewing the support loadings and comparing the calculated combined loads "DW + TH + OBE", "DW + TH + DBE" and "DW + TH + LOCA" with the allowable loads for upset and faulted conditions. The seismic loads are not combined with pipe rupture loads (LOCA). The primary loop, surge line, residual heat removal (RHR) line and accumulator line break LOCA loads have been eliminated by the application of Leak Before Break (LBB) analysis as discussed in LR Section 2.1.6, Leak-Before-Break. The allowable stress acceptance criteria for the PBNP Plant RCL piping primary equipment steam generator supports followed the FSAR Appendix A.5, to the extend possible and was supplemented by other ASME Section III, Subsection NF, 1974 Edition (Reference 16) and the American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, (Reference 19) criteria as required. The acceptance criteria for component support as listed in Table A.5-3 of the FSAR, provides stress limits and specific values for defined loading conditions.

Description of Analyses and Evaluations

The steam generator support loads from the RCL piping system analyses as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports, and the current design basis steam generator support loads and stress margins are used to calculate the stress margins available for EPU for the steam generator supports. The steam generator upper, steam generator lower lateral frame, and the steam generator columns are evaluated for the stress margin values. The stress margin values are summarized in Table 2.2.2.5-6 for the loading combinations as specified in the acceptance criteria in the PBNP FSAR in Appendix A.5, to the extend possible and was supplemented by ASME Section III, Subsection NF, 1974 Edition (Reference 16) and the American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP has evaluated the impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the steam generator supports. The aging evaluations approved by the NRC in Section 3.5 of the License Renewal SER, NUREG-1839 (Reference 8), for the steam generator supports remain valid for the EPU conditions. The aging management evaluations for the steam generator supports in Section 3.5 of the SER, and in WCAP-14422 Revision 2-A, License Renewal Evaluation: Aging Management Evaluation for Reactor Coolant System Supports (Reference 18).

Results

The stress margins available for EPU for the steam generator upper supports, steam generator lower lateral frame, and the steam generator columns are evaluated and summarized in Table 2.2.2.5-6 for the upset and faulted conditions. In all cases, the calculated stresses are less than the allowable and there are margins available.

Conclusions

The evaluation concludes that there is no adverse effect on the ability of steam generator support to operate at the EPU conditions.

2.2.2.5.15 Steam Generators and Supports Overall Conclusion

Each of the preceeding subsections which presented the evaluation results for steam generator supports, structural integrity, thermal-hydraulic performance, and tube vibration and wear concluded that the pertinent acceptance criteria are met. The steam generators and supports will continue to perform acceptably under the proposed EPU conditions assuming the previously described modifications are implemented. Therefore, PBNP finds the proposed EPU acceptable to the operation of the steam generators.

2.2.2.5.16 References

1. ASME Section III, Rules for Construction of Nuclear Vessels, 1965 Edition through Summer 1966 Addenda

2. EPRI PWR Primary Water Chemistry Guidelines, Volume 1, Revision 5, TR-105714-V1R5, March 2003

3. EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines, Revision 6, 1008224, Final Report, December 2004

4. Strategic Primary Water Chemistry Optimization Plan, NP 3.2.6, August 8, 2007

5. Secondary Strategic Water Chemistry Optimization Plan, NP3.2.5, August 1, 2007

6. Secondary Water Chemistry Monitoring Program, NP 3.2.3, May 10, 2006

7. Primary Water Chemistry Monitoring Program, NP 3.2.2, March 14, 2006

8. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Power Plant, Units 1 and 2, December 2005

9. Regulatory Guide 1.20, Revision 3, Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing, March 2007

10. NEI 97-06, Rev. 2, Steam Generator Program Guidelines, May 2005

11. ASME Section III, Rules for Construction of Nuclear Power Plant Components, 1980 Edition Winter 1982 Addendum or Later Editions

12. P. Meijers, Plates With a Doubly-Periodic Pattern of Circular Holes Loaded in Plane Stress or in Bending, Proceedings of the First International Conference on Pressure Vessel Technology, Part 1, Design and Analysis, ASME, 1969

13. WCAP 14602, Point Beach Nuclear Plant Unit 2 Steam Generator Replacement Engineering Report, March 1996

14. ASME Section III, Rules for Construction of Nuclear Power Plant Components, 1977 Edition through Winter 1978 Addenda

15. ASME Section III, Rules for Construction of Nuclear Power Plant Components, Subsection NB requirements,1986 Edition

16. ASME Section III, Rules for Construction of Nuclear Power Plant Components, Subsection NF, 1974 Edition

17. ASME Section III, Rules for the Construction of Nuclear Power Plant Components, 1989 Edition, through 1989 Addenda

18. WCAP-14422, Rev 2-A, License Renewal Evaluation: Aging Management Evaluation for Reactor Coolant System Supports, December 2000

19. American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, Eighth Edition

20. T.K. Emera and E.C. Rossow, Stresses in Elbows Created by Supporting Lug Load, ASME Pressure Vessels and iping Conference, San Francisco, California, June 1979

21. Regulatory Guide 1.20, Revision 3, Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing, March 2007

Table 2.2.2.5-1 PBNP Unit 1 Model 44F EPU Stress Summary

Component	Stress Category	Section (2)	Stress (ksi)/Fatigue		Allowable (ksi)/Fatigue	Comments
			Baseline	EPU		
Primary Side Components						
Divider Plate	P_m+P_b+Q	Section 1-IS	73.461	73.461	69.9	(1)
	Fatigue	Section 1-IS	0.1175	0.2708	1.0	
Primary Chamber, Tubesheet and Stub Barrel Complex	P_m+P_b+Q	Section A-A	51.56	59.81	90.0	
	Fatigue	Section A-A	0.0565	0.1104	1.0	
Tube-to-Tubesheet Weld	P_m+P_b+Q	Section B-B	53.807	62.42	79.8	
	Fatigue	Section A-A	0.9862	0.9831	1.0	
Tubes	P_m+P_b+Q	Section A-A	57.6	66.8	80.0	
	Fatigue	Section A-A	0.4452	0.9252	1.0	
Secondary Side Components						
Upper Shell Drain	Fatigue	Section S-S	37.19	43.13	52.35	
	P_m+P_b+Q	Section S-S	0.9352	0.9817	1.0	
Feedwater Nozzle	P_m+P_b+Q	Section A-A	57.2	68.68	90.0	
	Fatigue	Section A-A	0.7571	0.8981	1.0	
Remnant Upper Shell Components	P_m+P_b+Q	B-B – (OS)	28.34	30.82	68.1	
		ASN-5 (Bolts)	71.9	77.3	84.8	
	Fatigue	B-B – (OS)	0.0116	0.0156	1.0	
		ASN-5 (Bolts)	0.7599	0.9421	1.0	

Table 2.2.2.5-1 PBNP Unit 1 Model 44F EPU Stress Summary

Component	Stress Category	Section (2)	Stress (ksi)/Fatigue Baseline	Stress (ksi)/Fatigue EPU	Allowable (ksi)/Fatigue	Comments
Inspection Ports	P_m+P_b+Q	Maximum	23.6	23.6	58.5	
	Fatigue	Pad	0.7511	0.7610	1.0	
		Bolts (4)	0.9306	0.9906	1.0	
Steam Outlet Nozzle Flow Limiters	P_m+P_b+Q	Section F1-1	27.09	27.09	25.95	(3)
	Fatigue	Section F1-2	0.184	0.2643	1.0	
Wrapper Support System Components	P_m+P_b+Q	N/A(5)				
	Fatigue	N/A(5)				

Notes:

1. A plastic analysis was performed to address test conditions.
2. IS = Inside surface; OS = Outside surface
3. A simplified elastic-plastic analysis was performed.
4. The interval between bolt replacements shall be the lesser of the following intervals:
   a. Ten years of operation since the previous bolt replacement
   b. Five hundred complete cycles from 0% power to 100% power and back to 0% power since previous bolt replacement
   c. One thousand 10% step power changes since previous bolt replacement
   d. Ten secondary side hydrotest at 1356 psig since previous bolt replacement
   e. One hundred heatup and cooldown cycles since previous bolt replacement
   f. 80 cycles of the Secondary Side Pressure Test since previous bolt replacement
5. These non-pressure retaining components exhibit stresses below allowables and fatigue usage < 0.003 and are unaffected by the EPU.

Table 2.2.2.5-2 PBNP Unit 2 Model Δ47 EPU Stress Summary

Component	Stress Category	Section (2)	Stress (ksi) Fatigue Baseline	Stress (ksi) Fatigue EPU	Allowable (ksi)/ Fatigue	Comments
Primary Side Components						
Divider Plate	P_m+P_b+Q	HL Side - Center of TS	[ ] a,c	[ ] a,c	69.9	(1)
	Fatigue		[ ] a,c	[ ] a,c	1.0	
Primary Chamber, Tubesheet and Stub Barrel Complex	P_m+P_b+Q	Section 1 - (OS)	[ ] a,c	[ ] a,c	116.0	$2S_y$
		Section 3 - (IS)	[ ] a,c	[ ] a,c	90.0	$3S_m$
	Fatigue	Section 4 - (IS)	[ ] a,c	[ ] a,c	1.0	
Tube-to-Tubesheet Weld	P_m+P_b+Q	Section 2 - Weld Root	[ ] a,c	[ ] a,c	77.55	(3)
	Fatigue	Section 2 -Weld Root	[ ] a,c	[ ] a,c	1.0	
Tubes	P_m+P_b+Q	Section A-A	[ ] a,c	[ ] a,c	79.8	Test Conditions
	Fatigue	Section A-A	[ ] a,c	[ ] a,c	1.0	
Blowdown Pipe	P_m+P_b+Q	Section 4 - Weld Root	[ ] a,c	[ ] a,c	78.0	(3)
	Fatigue	Section 4 - Weld Root	[ ] a,c	[ ] a,c	1.0	
Secondary Side Components						
Feedwater Nozzle	P_m+P_b+Q	Section 3 - (IS)	[ ] a,c	[ ] a,c	124.9	$2S_y$
		Section 1 - (IS)	[ ] a,c	[ ] a,c	90.0	$3S_m$
	Fatigue	Section 5	[ ] a,c	[ ] a,c	1.0	
Secondary Manway	P_m+P_b+Q	ASN 1 - (IS)	[ ] a,c	[ ] a,c	90.0	
		ASN 5 - (Bolts)	[ ] a,c	[ ] a,c	84.8	
	Fatigue	ASN 2 - (IS)	[ ] a,c	[ ] a,c	1.0	
		ASN 5 - (Bolts)	[ ] a,c	[ ] a,c	1.0	

Table 2.2.2.5-2 PBNP Unit 2 Model Δ47 EPU Stress Summary

Component	Stress Category	Section (2)	Stress (ksi) Fatigue		Allowable (ksi)/ Fatigue	Comments
			Baseline	EPU		
Inspection Ports	P_m+P_b+Q	Section B-B - (IS)	[ ] a,c	[ ] a,c	90.0	
		Section F-F - (Bolts)	[ ] a,c	[ ] a,c	83.1	
	Fatigue	Section B-B - (IS)	[ ] a,c	[ ] a,c	1.0	
		Section F-F - (Bolts)	[ ] a,c	[ ] a,c	1.0	
Steam Outlet Nozzle, Elliptical Head, Upper Shell Complex	P_m+P_b+Q	Section 2 - (IS)	[ ] a,c	[ ] a,c	90.0	
		Section 10 - (IS)	[ ] a,c	[ ] a,c	58.5	(3)
		Section V1	[ ] a,c	[ ] a,c	78.9	
	Fatigue	Section 2 - (IS)	[ ] a,c	[ ] a,c	1.0	
		Section 10 - (IS)	[ ] a,c	[ ] a,c	1.0	
		Section V1	[ ] a,c	[ ] a,c	1.0	
Wrapper Supporting Structures	P_m+P_b+Q	≤ [ ] a,c Stress Ratio				No Impact from EPU
	Fatigue	<[ ]a,c				

Notes:
1. A plastic analysis was performed to address test conditions.
2. IS = Inside surface; OS = Outside surface
3. A simplified elastic-plastic analysis was performed.

Table 2.2.2.5-3 Delta-P Summary for PBNP Unit 1 (Model 44F SG) and Unit 2 (Model Δ47 SG) 10% Plugging

Case	Limiting Transient	Condition	Delta-P (psi)	Allowable (psi)
High T_{avg} -10% Plugging	10% Step Increase	Normal	[ ] a,c	1700
	100% Power at Initiation of Transients	Upset	[ ] a,c	1870
Low T_{avg} - 10% Plugging	Unit Loading – 0-100% Power	Normal	[ ] a,c (1)	1700
	100% Power at Initiation of Transients	Upset	[ ] a,c	1870

Notes:

1. Pressure differential was modified based on a conservative pressure drop of [ ]a,c psi determined from thermal-hydraulic data provided for this condition.

Table 2.2.2.5-4 PBNP Unit 1 Model 44F RSG Tubesheet, Channel Head and Cylinder Evaluation Results for Increased Primary-to-Secondary Design ΔP of 1700 psi

Analysis Section (1)	Case 1: Elastic Analysis – Full Bending Moment Capabilities at All Sections					
	P_m (ksi)	Allowable (ksi)	Ratio	$P_m + P_b$ (ksi)	Allowable (ksi)	Ratio
A-A	3.70	30	0.123	14.85	45	0.330
A1-A1	2.48	8.34	0.297	11.29	11.69	0.966
B-B	12.04	30	0.401	13.21	45	0.294
C-C	15.88	19.4	0.819	35.40	29.1	1.216(3)
C1-C1	15.92	30	0.531	45.19	45	1.004(3)
D-D	8.56	19.4	0.441	9.99	29.1	0.343
Analysis Section (1)	Case 2: Elastic Analysis – Pin Connection at Tubesheet to Channel Head Joint					
	P_m (ksi)	Allowable (ksi)	Ratio	$P_m + P_b$ (ksi)	Allowable (ksi)	Ratio
A-A	3.58	30	0.119	16.03	45	0.356
A1-A1	2.36	8.34	0.283	12.19	11.69	1.043(3)
B-B	13.60	30	0.453	16.23	45	0.361
C-C	15.88(2)	19.4(2)	0.819	35.40 (2)	58.2(2)	0.608
C1-C1	19.40	30	0.647	27.66	45	0.615
D-D	8.50	19.4	0.438	9.96	29.1	0.342

Notes:

1. See Figure 2.2.2.5-1 for location of analysis sections.
2. The P_m and $P_m + P_b$ values are from Case 1. The $P_m + P_b$ stress intensity is considered secondary ($P_m + Q_b$), and meets the $3S_m$ limit of 58.2 ksi.
3. Ratios greater than one exceed the elastic allowable, and positive compliance with NB-3228.1 of the 1980 + W82 ASME Code is demonstrated by lower bound plastic limit analyses.

Table 2.2.2.5-5 PBNP Unit 2 Δ47 RSG Tubesheet, Channel Head and Cylinder Evaluation Results for Increased Primary-to-Secondary Design DP of 1700 psi

Analysis Section (1)	P_m (ksi)	Allowable (ksi)	Ratio	$P_m + P_b$ (ksi)	Allowable (ksi)	Ratio
	Case 1: Elastic Analysis – Full Bending Moment Capabilities at All Sections					
A-A	3.54	30	0.118	15.01	45	0.334
A1-A1	2.40	8.43	0.285	11.07	11.5	0.963
B-B	13.09	30	0.436	14.36	45	0.319
C-C	16.63	26.7	0.623	37.84	40	0.946
C1-C1	16.62	30	0.554	46.30	45	1.029(3)
D-D	11.63	26.7	0.436	12.95	40	0.324
	Case 2: Elastic Analysis – Pin Connection at Tubesheet to Channel Head Joint					
Analysis Section (1)	**P_m (ksi)**	**Allowable (ksi)**	**Ratio**	**$P_m + P_b$ (ksi)**	**Allowable (ksi)**	**Ratio**
A-A	3.41	30	0.114	16.38	45	0.364
A1-A1	2.27	8.43	0.269	12.09	11.5	1.051(3)
B-B	14.97	30	0.499	18.00	45	0.400
C-C	16.63(2)	26.7(2)	0.623	37.84(2)	80(2)	0.473
C1-C1	20.70	30	0.690	28.15	45	0.626
D-D	11.57	26.7	0.433	12.82	40	0.321

Notes:

1. See Figure 2.2.2.5-1 for location of analysis sections.
2. The P_m and $P_m + P_b$ values are from Case 1. The $P_m + P_b$ stress intensity is considered secondary ($P_m + Q_b$), and meets the $3S_m$ limit of 80 ksi.
3. Ratios greater than one exceed the elastic allowable, and positive compliance with NB-3228.1 of the 1980 + W82 ASME Code is demonstrated by lower bound plastic limit analyses.

Table 2.2.2.5-6 RCL Primary Equipment Steam Generator Support Member Stresses Percent of Allowable = (Actual/Allowable) x 100%

Member	Upset		Faulted	
	Allowable	Stress Ratio, %	Allowable	Stress Ratio, %
Steam Generator Upper Supports	(Note 1)	(Note 1)	1500 kips	[ ] b,c
Steam Generator Lower Lateral Frame	32 ksi (2)	[ ] b,c	42 ksi (2)	[ ] b,c
Steam Generator Columns	514 kips (2)	[ ] b,c	856 kips (2)	[ ] b,c

Notes

1. The Steam Generator Upper Support OBE loads are 1/2 of the DBE loads. Faulted case governs.
2. Allowable load or stress is calculated based on ASME B&PV Code, Section III, Subsection NF, 1974 Edition.

Figure 2.2.2.5-1 PBNP Units 1 and 2 SG Two Tier Steam Dryer Layout

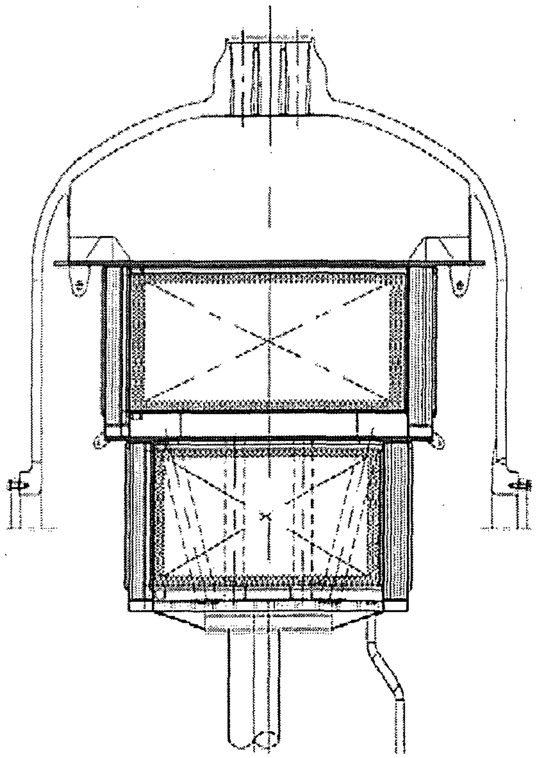
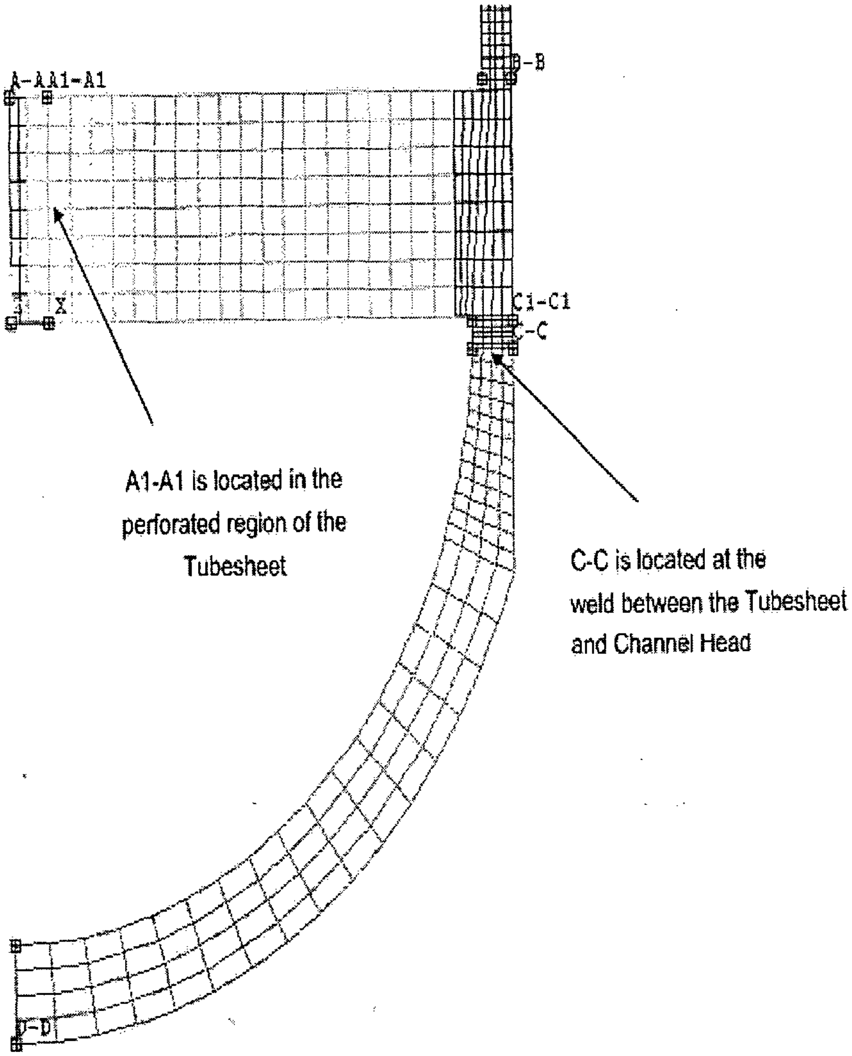


Figure 2.2.2.5-2 Analysis Sections for Tubesheet, Channel Head and Cylinder



2.2.2.6 Reactor Coolant Pumps and Supports

2.2.2.6.1 Regulatory Evaluation

The reactor coolant pumps (RCPs) are described in FSAR, Chapter 4. The RCP supports are described in FSAR Section 4.2. Each reactor coolant pump is a vertical, single stage, centrifugal pump equipped with a controlled leakage seal assembly. The functions of the RCPs are

- to maintain an adequate cooling flow rate by circulating a large volume of primary coolant water at high temperature and pressure through the reactor coolant system (RCS).
- to provide adequate flow coastdown to prevent core damage in the event of a simultaneous loss of power to both pumps.
- to provide a portion of the reactor coolant pressure boundary (the pressure boundary parts of the RCP).

The Reactor Coolant Pump Supports (RCP columns and lateral tie rods) were reviewed for the impact of Reactor Coolant Loop (RCL) piping loads under EPU conditions. Supports for the Reactor Coolant Pumps and for the RCL piping are discussed in FSAR in Section 4.2. The RCL piping loads under EPU conditions are discussed in LR Section 2.2.2.1, NSSS Piping, Components and Supports. The RCL piping loads on the RCP supports due to the deadweight, thermal expansion, seismic operational basis earthquake (OBE), and seismic safe shutdown earthquake (SSE) loading cases are obtained from LR Section 2.2.2.1. The LOCA and the pipe break analyses from the current design basis remain valid for the EPU program as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports.

The RCP supports stress margin values are evaluated for the EPU program based on the stress margin data from the current design basis and the RCP support loads obtained from the evaluation from the RCL piping system analyses for the EPU program as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports.

Current Licensing Basis

The generic Current Licensing Basis in Section 2.2.2, above, applies to the reactor coolant pumps and supports. In addition to the general discussion regarding review for plant license renewal in Section 2.2.2, the specific review for reactor coolant pumps and supports is documented in the license renewal safety evaluation:

- Safety Evaluation Report (SER) related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 5)

Section 2.3.1.1 of the SER identifies that the reactor coolant pump casing, main flange, thermal barrier flange, the bolting for the reactor coolant pump main closure, and the reactor coolant pump lugs are among the component groups of the reactor coolant system that require an aging management review. Section 3 of the SER identifies the aging management programs that are applicable to reactor coolant system components.

On the basis of its review, the staff concluded that PBNP had adequately identified the aging effects and the aging management programs credited for managing the effects of the reactor coolant (Class 1) components, such that there is reasonable assurance that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation.

Time-limiting aging analyses (TLAAs) are discussed in Section 4.0 of the SER. In particular, Section 4.3 of the SER discusses metal fatigue. The reactor coolant pump is included in the discussion of metal fatigue as it relates to meeting the intent of ASME Boiler and Pressure Vessel Code, Section III, Class 1 equipment. To address this issue, estimates were made that the expected number of transients to which the reactor coolant pump would be subject over the 60 year life of the plant with license renewal would be bounded by the number of transients considered in the analyses performed for the original 40 year life of the plant. A commitment was also made to implement a Fatigue Monitoring Program to provide assurance that the number of design cycles would not be exceeded during the period of extended operation.

It is also noted that where the reactor coolant pumps are placed are not among the fatigue sensitive component locations which are included in the evaluation of environmentally assisted fatigue discussed in Section 4.3.10 of the SER.

Section 4.4.2 of the SER discusses the reactor coolant pump flywheel TLAA. Westinghouse Topical Report WCAP-14535A, Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination (Reference 1), presents an evaluation of the probability of failure over an extended operating period of 60 years. Based on WCAP-15666 (Reference 3) and in accordance with NRC approval of license amendments 218/223 dated June 6, 2005, PBNP revised the ISI frequency of flywheel examination to once every 20 years. The staff concluded that the Inservice Inspection Program requirements for the reactor coolant pump flywheels at PBNP will continue to ensure that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

As stated in the SER, Section 4.4.3, Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis, Reference 2), was deleted by PBNP from the License Renewal Application (LRA). The NRC staff found deletion of LRA Section 4.4.3 acceptable. RCP casing analysis is not considered a TLAA, in accordance with the definition of 10 CFR 54.3.

2.2.2.6.2 Technical Evaluation

Evaluations were performed to assess the impact on the reactor coolant pumps (RCPs), motors and supports of Units 1 and 2 to support an uprate of the core thermal power to 1800 MWt. Revised operating conditions including temperature, flow and applicable transients were compared to existing conditions to determine if the current parameters bounded the uprated parameters. In the cases where the uprated conditions were not bounded or deemed to be minor changes with no significant impact, new evaluations were performed. In those conditions the evaluations proved the reactor coolant pumps, motors and supports were all adequate per the design documentation.

Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The major inputs used in this evaluation are the EPU Performance Capability Working Group (PCWG) parameters provided in LR Section 1.1, Nuclear Steam Supply System Parameters, and the EPU nuclear steam supply system (NSSS) design transients provided in LR Section 2.2.6. These Licensing Report sections provide the operating and transient conditions for the EPU. The RCPs are installed in the RCS cold leg, between the steam generator outlet and the reactor vessel inlet. Therefore, only the cold-leg temperatures and the cold-leg transients are applicable to the RCPs. These operating and transient conditions differ in some cases from those specified in the RCP equipment specification to which the PBNP RCPs were originally designed and analyzed.

Operational loads were determined to be less than or equal in magnitude to the loads that were previously analyzed with no changes to the load application points and numbers of occurrences.

Assumptions

Inputs for seismic analysis of the reactor coolant pump including seismic accelerations and pump component mass and stiffness have not changed due to the EPU conditions. Therefore, seismic analyses and nonpressure boundary component evaluations were unaffected by the EPU. The evaluation of the RCPs for the EPU compared the operating temperatures, flows and pressures defined in the EPU parameters to the pressures, temperatures and flows considered in previous analyses of the RCPs. In addition, the NSSS design transients for the EPU were compared to the transients considered in previous evaluations. Where temperatures, pressures, and NSSS transients considered in previous analyses enveloped the temperatures, pressures, and NSSS transients defined for the EPU, no additional analysis was required. For the inputs that were not enveloped by the previously analyzed parameters, RCP structural analyses and evaluations were performed as necessary to incorporate the revised design inputs.

Acceptance Criteria

Where these analyses and evaluations were required, the acceptance criteria were that the Point Beach RCP pressure boundary components meet the stress limits and fatigue usage requirements of the American Society of Mechanical Engineers (ASME) Code, Section III for plant operation with the EPU conditions. While the RCP is not an ASME Code pressure vessel, the pressure retaining parts of the RCPs were designed, fabricated, inspected, and tested in conformance with the ASME Code.

The reactor coolant pumps and motors were evaluated for the Point Beach EPU parameters provided in LR Section 1.1, Nuclear Steam Supply System Parameters, and best estimate flows at an assumed core power of 1800 MWt.

The steam generator outlet temperatures and best-estimate flows were considered in a hydraulic analysis using the operating characteristics of the PBNP reactor coolant pumps. This hydraulic analysis calculates the power requirements for the impeller that operates at the highest power for both hot and cold operation. The RCP motors were evaluated to confirm that they continue to meet their design requirements.

Description of Analyses and Evaluations

Operating Temperature and Pressure

The EPU PCWG parameters (see Licensing Report Section 1.1, Nuclear Steam Supply System Parameters) for PBNP were used to evaluate the acceptability of the RCPs. In the EPU PCWG parameters for PBNP, there were no changes from the current reactor coolant pressure of 2250 psia for any of the EPU cases. The maximum EPU RCS T_{cold} was less than the equipment specification operating temperature of 550°F. Since none of the temperatures exceeded the previously considered temperature and the pressure does not change, the EPU NSSS parameters were bounded by those defined in the equipment specification. No further evaluation of the pressure boundary integrity was required for the operating temperature and pressure associated with the EPU.

Transient Discussion

The NSSS design transients were recalculated for the EPU Program. The recalculated transients had some temperature and pressure changes that were different from the design transients given in the equipment specification or used in the original analyses.

The EPU NSSS design transients are provided in LR Section 2.2.6, NSSS Design Transients. Only the cold-leg transients were applicable to the RCP evaluation. Comparison of the old and new transients reveals that the majority of the new transients are either equal to the existing ones, bounded by the existing ones or are unaffected by the uprate. In the case of the Plant Heatup/Cooldowns (1), Large Step Load Decrease (4) and the Loss of Power (10) transients there were very minor increases to temperature or pressure. The increases have a negligible effect on the RCP.

Pump Casing Stress Analysis

The transients considered in the original analysis of the casing differed from the transients specified for the EPU and in most original cases the transients considered were more severe. The exception to this was the temperature range spanned by the heatup and cooldown transients. In the original stress analysis, the temperature range considered was 433°F, while the temperature range is 447°F, from 100°F to 547°F (547°F is the hot zero power temperature). The maximum values of the stress intensity occur at the suction nozzle area of the casing. Adjusting the calculated thermal stresses for this difference resulted in small increases in the primary-plus-secondary-stress intensity and the maximum thermal-plus-pressure-plus-mechanical-stress intensity. The stress intensities remain less than the ASME Code allowable values. The values of these stress intensities are shown in Table 2.2.2.6-1. Note that the hot zero power temperature has not changed as a result of the EPU.

The original calculations resulted in a cumulative usage factor of zero since the calculated stresses were below the lowest alternating stress value on the fatigue curve. This is still true for the EPU conditions.

Main Flange Stress Analysis

The main flange is protected from the high reactor coolant temperatures by the thermal barrier, and thus sees much lower temperatures than those in the parts of the pump directly exposed to the primary coolant. This protection also means that the effect of the primary system cold-leg transients on the main flange is small, except for the heatup and cooldown transients. As was the case for the main flange bolted joint analysis, the original analysis still envelopes the maximum stress levels for the EPU conditions. The stresses remain within the ASME Code allowable values. The values of the stresses and the cumulative usage factor are shown in Table 2.2.2.6-1.

Main Flange Bolted Joint Stress Analysis

The original analysis showed that the transients other than the heatup and cooldown transients did not affect the fatigue usage of the main flange bolted joint. In the case of the heatup and cooldown transients the design pressure and temperature (2485 psig and 650°F) envelop the transient conditions and therefore are bounded. The cumulative usage factor for the main flange studs thus remained as calculated. The highest stress in the studs occurred for the loss-of-load transient, which had a maximum pressure increase of 500 psi in the original analysis. This maximum pressure increase is now defined as 450 psi for the EPU, and thus the original analysis still envelopes the maximum stress levels for the EPU conditions. The stresses remain within the ASME Code allowable values. The values of the stresses and the cumulative usage factor are shown in Table 2.2.2.6-1, RCP Pressure Retaining Component Stresses and Usage Factors.

Flow Induced Vibration Analysis

Analysis of flow induced vibration is not included in the licensing basis for PBNP. Reactor coolant pumps were considered and all unaffected by EPU conditions due to their heavy construction.

RCP Motors

For the RCP motors, a hydraulic analysis was performed using best estimate flows and modeling the characteristics of the PBNP RCPs. The hydraulic analysis is used to calculate the required brake horsepower for the RCP motors and the loading on the thrust bearings. Application of these data revealed a worst case load condition of 5657 horsepower (hp) at operating temperature and a worst case load condition of 7212 hp at 70°F. Both of these conditions are well within the applicable nameplate ratings and therefore the uprated conditions were deemed acceptable.

Per the Equipment Specification the motor is required to drive the pump continuously under hot loop condition without exceeding a temperature rise of 75°C on the stator winding (reference NEMA MG 1, Section III, Part 20.8, Class B temperature rise limit with an ambient air temperature of 50°C). Temperature tests performed on an electrical duplicate RCP stator resulted in a calculated temperature rise at the Point Beach hot loop nameplate rating (6000 HP) of 61.9°C. Adequate margin exists for continuous operation of the unit at loads in excess of the original hot loop 6000 HP nameplate rating. Per the Equipment Specification the motor is required to start with a minimum 80% starting voltage, against the reverse flow of the other pump running at full speed, under cold loop condition. The limiting component for this type of starting duty is the rotor cage winding. A conservative all heat stored analysis is used to determine if the cage winding temperature rise exceeds the design limits of 300°C on the rotor bars and 50°C on the resistance rings. Using the load torque curve, the starting temperature for the rotor bars and resistance rings have been calculated. The results do not exceed design requirements and are calculated at 290.1°C on the rotor bars and 43.3°C on the resistance rings. The motor can therefore safely accelerate the load under worst-case condition.

The RCP motor thrust bearings were evaluated to address the change in cold-loop temperature. The cooler, denser RCS water (523.1°F vs. 550°F design criteria) increases the amount of downward thrust produced by the RCP. Per the original equipment specification the thrust bearings are designed to withstand 101,200 lbs of downward thrust during normal operating conditions with an expected loading off 55,000 lbs. The RCS temperature change produces a water density increase of 3.5%. Applying this increase to the original value of 55,000 lbs produces a net downward thrust of 56,923 lbs, far below the design value of 101,200 lbs. Consequently the thrust bearings are deemed acceptable for the uprated conditions.

RCP Supports

The RCL piping loads on the Reactor Coolant Pump Supports due to deadweight (DW), thermal (TH) expansion, seismic design basis earthquake (DBE) and loss-of-coolant accident (LOCA) loading cases are obtained from the piping system analyses for the EPU program as described in LR Section 2.2.2.1, NSSS Piping, Components and Supports. Operational basis earthquake (OBE) loads are also included in the support evaluation.

The Reactor Coolant Pump Supports (columns and tie rods) assessment consisted of reviewing the support loadings and comparing the calculated combined loads "DW + TH + OBE", "DW + TH + DBE" and "DW + TH + LOCA" with the allowable loads for upset and faulted conditions. The seismic loads are not combined with pipe rupture loads (LOCA). The primary loop, pressurizer surge line, residual heat removal (RHR) line and accumulator line break LOCA loads have been eliminated by the application of Leak Before Break (LBB) analysis as discussed in LR Section 2.1.6, Leak-Before-Break.

The allowable stress acceptance criteria for the RCL piping primary equipment Reactor Coolant Pump Supports (columns and tie rods) followed the FSAR in Appendix A.5, to the extent possible and was supplemented by other ASME Section III, Subsection NF, 1974 Edition and the American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, criteria as required.

Evaluation of Impact on License Renewal Programs

There is no change to the number of design transient cycles, and there is no change to the cumulative usage factors for the reactor coolant pump pressure boundary components based on those cycles. While a small increase in stress was calculated for the casing, as described above, stresses remain within ASME Code allowables. The operating temperature of the reactor coolant pump is not increasing. There is thus no impact on the License Renewal programs and renewed plant operating license evaluations as described in the License Renewal SER.

2.2.2.6.3 Results

The results of the evaluations of the RCP pressure retaining components are given in Table 2.2.2.6-1 for the major RCP pressure retaining components. Some of these components required the recalculation of stresses or cumulative usage factors for the EPU conditions, while for other major components, no changes to the stress and usage factor were necessary. All of the stresses and cumulative usage factors given in Table 2.2.2.6-1 are within the allowable values given in the ASME Code. In addition, the supports were confirmed to be acceptable under EPU conditions.

The reactor coolant pump motors were evaluated in the following three conditions for the under loadings of 5657 hp for worst-case hot-loop operation and 7212 hp for worst-case cold-loop operation:

- Continuous operation at hot-loop (100% power) conditions
- Continuous operation at cold-loop (70°F) conditions
- Thrust bearing loading conditions.

The RCP motor brake horsepower results are provided below. The worst-case hot-loop load under the EPU operating conditions is 5657 hp. The worst-case cold-loop load under the EPU operating conditions is 7212 hp. These loadings are less than the motor nameplate ratings of 6000 hp for hot-loop operation and 7500 hp for cold-loop operation. The motors have been shown by test and analysis to operate within the equipment specification limits at the nameplate ratings. Per design, motor operation is acceptable for any load up to the hot-loop nameplate rating of 6000 hp and the cold-loop nameplate rating of 7500 hp. Thus, the revised motor loadings are acceptable based on the loadings being within the nameplate ratings of the motors.

The thrust-bearing loading used for the motor design is given in the equipment specifications for the motor. Performance of the thrust bearings in a reactor coolant pump motor can be adversely affected by excessive or inadequate loading. The analysis for the EPU conditions indicates an increase in the downward impeller thrust from 55,000 lbs. to 56,923 lbs. for hot-loop operation due to the change in cold-leg temperature. For hot-loop operation, this increase in impeller down thrust results in a net decrease in the up thrust loading on the thrust bearing. In comparison to the design normal operating thrust-bearing load of 101,200 lbs given in the equipment specifications, this change is not considered significant and the thrust bearings are acceptable for the EPU loads.

The stress margins available for Reactor Coolant Pump Support columns and the Reactor Coolant Pump tie rods are evaluated and summarized in Table 2.2.2.6-2 for the upset and faulted conditions. In all cases, the calculated stresses are less than the allowable and there are margins available. The evaluation concludes that there is no adverse effect on the ability of Reactor Coolant Pump Support to operate at the EPU conditions.

Since the new reactor coolant pump motor loads are within the nameplate ratings of the motors, the motor temperature rise for hot and cold operating conditions will be within the NEMA requirements and the first two areas continue to meet these requirements. In comparison to the normal operating thrust-bearing load of 101,200 lbs, the thrust bearing load changes due to the EPU are not considered significant and the thrust bearings remain acceptable for the EPU loads. Therefore, the reactor coolant pump motors at Point Beach are acceptable for the EPU conditions.

2.2.2.6.4 Conclusions

Because the calculated stresses and cumulative usage factors remain below the allowable values given in the ASME Code, the structural integrity of the RCPs and supports remains adequate under the proposed EPU conditions. The EPU conditions, and the analyses and evaluations performed in support of the EPU, do not impact the aging management reviews, aging management programs, and TLAAs associated with the reactor coolant pumps and supports for the PBNP License Renewal. The reactor coolant pumps and supports continue to meet the current licensing basis with respect to PBNP GDCs 1, 2, and 9.

PBNP has reviewed the evaluations to the structural integrity of the RCPs and their supports. For the reasons set forth above, PBNP concludes that the effects of the proposed EPU have been adequately addressed. Therefore PBNP finds the proposed EPU acceptable with respect to the structural integrity of the RCPs and their supports.

2.2.2.6.5 References

1 WCAP-14535A, Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination, November 1996

2 ASME Code Case N-481, Alternate Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1, March 1990

3 WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination, July 2001

Table 2.2.2.6-1
RCP Pressure Retaining Component Stresses and Usage Factors

Component	EPU Stresses and Usage Factors		Allowable(1)	Comments
Casing	Primary Membrane Stress Intensity	16,359 psi	16,700 psi (S_m)	The original calculations had a zero usage factor since the calculated stresses were below the lowest S_a value on the fatigue curve. This is still true for the Point Beach EPU conditions. {Original stress intensities were 16,359 psi, 22,924 psi, and 41,898 psi, respectively.}
	Primary + Secondary Pressure and Mechanical Loads	23,664 psi	25,000 psi (1.5 S_m)	
	Maximum Steady State Thermal + Pressure and Mechanical Stresses	43,251 psi	50,100 psi (3 S_m)	
	Usage Factor	See Comment	1.0	
Main Flange	General Primary Membrane Stress Intensity	4370 psi	20,000 psi (S_m)	No changes from the original calculation.
	Local Primary Membrane Stress Intensity	10,979 psi	30,000 psi (1.5 S_m)	
	Primary + Secondary Stress Intensity	31,524 psi	60,000 psi (3 S_m)	
	Usage Factor	0.025	1.0	

Table 2.2.2.6-1
RCP Pressure Retaining Component Stresses and Usage Factors

Component	EPU Stresses and Usage Factors		Allowable[1]	Comments
Main Flange Studs	Maximum Service Stress, Averaged Across Section	35,901 psi	55,800 psi (2 S_m)	No changes from the original calculation. Allowable stresses are based on SA-193, Grade B7 material. Current drawings show the stud material is SA-540, Grade B24, Class 4, or Grade B23, Class 4. Both of these have higher allowable stresses than the SA-193, Grade B7 material originally considered.
	Maximum Service Stress at Periphery of Cross Section from Tension + Bending	76,224 psi	83,700 psi (3 S_m)	
	Usage Factor	0.29	1.0	

1. Allowables from ASME Section III 1965 code.

Table 2.2.2.6-2
RCL Primary Equipment Reactor Coolant Pump Support Member Stresses
Percent of Allowable = (Actual/Allowable) x 100%

Member	Upset		Faulted	
	Allowable	Stress Ratio, %	Allowable	Stress Ratio, %
Reactor Coolant Pump Tie Rods	(Note 1)	(Note 1)	900 kips(2)	[ ]b,c (3)
Reactor Coolant Pump Columns	543 kips(2)	[ ]b,c	894 kips(2)	[ ]b,c

Notes
1. There are no OBE/DBE loads on the RCP Tie Rods due to a 3/8 inch hot gap.
2. Allowable loads are calculated based on the ASME B&PV Code, Section III, Subsection NF, 1974 Edition.
3. RCP Tie Rod faulted stress ratio is due to the LOCA load.

2.2.2.7 Pressurizer and Supports

2.2.2.7.1 Regulatory Evaluation

Introduction

The PBNP Units 1 and 2 pressurizers are vertical, cylindrical vessels with hemispherical top and bottom heads, constructed of carbon steel with internal surfaces clad with austenitic stainless steel. The pressurizer is insulated to minimize heat loss from the pressurizer vessel. The insulation is removable to permit examination of the pressurizer as required for inservice inspection. The pressurizer vessel contains replaceable direct immersion heaters, multiple safety and pressurizer power operated relief valves (PORVs), a spray nozzle, and interconnected piping, valves and instrumentation. The heaters are sheathed in austenitic stainless steel.

The pressurizer functions to absorb any expansion or contraction of the primary reactor coolant due to changes in temperature and/or pressure and, in conjunction with the pressure control system components, to keep the Reactor Coolant System (RCS) at the desired pressure. The first function is accomplished by keeping the pressurizer approximately half full of water and half full of steam at normal conditions and allowing pressurizer inflow or outflow through the surge line as required. The second function is accomplished by keeping the temperature in the pressurizer at the water saturation temperature (T_{sat}) corresponding to the desired pressure. The temperature of the water and steam in the pressurizer can be raised by operating electric heaters at the bottom of the pressurizer and lowered by introducing relatively cool spray water into the steam space at the top of the pressurizer.

The components in the lower end of the pressurizer (such as the surge nozzle, lower head/heater well and support skirt) are affected by pressure and surges through the surge nozzle. The components in the upper end of the pressurizer (such as the spray nozzle, safety and relief nozzle, upper head/upper shell, manway and instrument nozzle) are affected by pressure, spray flow through the spray nozzle, and steam temperature differences.

The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot leg (T_{hot}) and cold leg (T_{cold}) temperatures are low. This maximizes the ΔT that is experienced by the pressurizer. Due to flow out of and into the pressurizer during various transients, the surge nozzle alternately sees water at the pressurizer temperature (T_{sat}) and water from the RCS hot leg at T_{hot}. If the RCS pressure is high (which means, correspondingly, that T_{sat} is high) and T_{hot} is low, then the surge nozzle will see maximum thermal gradients; and thus, experience the maximum thermal stress. Likewise, the spray nozzle and upper shell temperatures alternate between steam at T_{sat} and spray water, which, for many transients, is at T_{cold}. Thus, if RCS pressure is high (T_{sat} is high) and T_{cold} is low, then the spray nozzle and upper shell will also experience the maximum thermal gradients and thermal stresses.

Note the pressurizer surge line evaluation is documented in the LR Section 2.2.2.1, NSSS Piping, Components and Supports

PBNP Current Licensing Basis

The generic Current Licensing Basis in LR Section 2.2.2, above, applies to the pressurizer and supports, with the following amplifications.

Each PBNP pressurizer is designed, fabricated, inspected and tested in accordance with the 1965 Edition of Section III of the ASME Boiler and Pressure Vessel Code. Quality control techniques used in the fabrication of the reactor coolant system were equivalent to those used in the manufacture of the reactor vessel which conforms to Section III of the ASME Code. The pressurizer design pressure is 2485 psig. This design pressure allows for operating transient pressure changes. The pressurizer is designed to withstand the effects of cyclic loads due to reactor system temperature and pressure changes. These cyclic loads are introduced by normal unit load transients, reactor trip, and startup and shutdown operation. The number of thermal and loading cycles used for design purposes is shown in Table 4.1-8 of the FSAR. For the pressurizer, the heatup and cooldown rates do not exceed 100°F per hour. An additional limitation is that spray cannot be used if the temperature difference between the pressurizer and spray fluid is greater than 320°F.

NRC Bulletin 88-11 (Reference 1) requested licensees to take certain actions to monitor thermal stratification in the pressurizer surge line because measurements indicate that top-to-bottom temperature in the surge line can reach 250°F to 300°F in certain modes of operation, particularly during heatup and cooldown. Westinghouse performed a plant specific analysis of the PBNP pressurizer surge line to demonstrate compliance with NRC Bulletin 88-11 (Reference 1), and the results are reported in WCAP-13509 (proprietary, Reference 2) and WCAP-13510 (nonproprietary, Reference 3). The results indicate that for PBNP Units 1 and 2, each surge line meets the stress limits and usage factor requirements, and the pressurizer surge nozzle meets the code stress allowables under thermal stratification loading and fatigue usage requirements of ASME Section III, 1986 Edition. Plant operating strategies as discussed in WCAP-13588, Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients, dated March 1993 (Reference 4), have an effect on the frequency and severity of pressurizer flow surges.

In addition, a plant-specific insurge/outsurge fatigue analysis was performed as part of the PBNP License Renewal Application (LRA) to demonstrate adequate structural integrity for a projected 60 year operational period. The following locations were selected for analysis:

- pressurizer surge nozzle
- heater penetration well
- lower instrument nozzle

These locations were determined to represent the bounding fatigue locations in the lower head region. The pressurizer surge nozzle is subjected to thermal shock in combination with thermal expansion piping loads, thermal stratification piping loads in the horizontal portion of the surge line, and pressure. The pressurizer heater tube and instrument penetrations are subjected to thermal shock and pressure. The Electric Power Research Institute (EPRI) FatiguePro software program, part of the Fatigue Monitoring Program described in FSAR Section 15.3, Time Limited Aging Analysis Supporting Activities, was customized to monitor fatigue-critical locations in the pressurizer's lower head at PBNP. An analysis was performed based on available real plant data to determine the incremental fatigue usage factor for known plant transients, including the effects of insurge/outsurge. ASME Code Section III Class 1 CUFs for the operating life of the plant were computed based on the results of real plant data, and expected future usage was computed using projections of expected plant cycles through the period of extended operation.

The technical approach used by PBNP is based on determining flow rates and heat transfer rates from the incoming fluid to calculate the temperature transients in the lower head components by using the FatiguePro program. This approach has been verified to be conservative, based on thermocouple data from another plant, as well as plant-specific comparisons between the FatiguePro calculated water temperature and the surge line temperature instrument reading in the region of the surge nozzle. The temperatures at the nozzle and lower head are calculated in FatiguePro completely independently from the surge line temperature instrument. As part of FatiguePro, stress histories, using finite element models of the pressurizer surge nozzle and hot leg RCS surge nozzle (including thermal sleeves), were computed based on the calculated fluid temperatures histories. The stress histories were used to compute fatigue usage in FatiguePro.

Plant data from various heatup/cooldown cycles since 1994 were analyzed to compute incremental fatigue usage for a heatup/cooldown cycle. The location with the highest fatigue usage in the pressurizer bottom head was determined to be at a heater penetration weld. However, for this location, the primary stress transient is not due to insurge and outsurge, but rather due to the general thermal expansion stress that arises from the global heatup and cooldown of the pressurizer. This location is a stainless steel weld to the tube and clad, very close to the low-alloy steel pressurizer shell. A high steady-state dissimilar-metal thermal expansion stress is established during the heatup and is relaxed during the cooldown. It is of a magnitude that overwhelms the small stress additions coming from insurges and outsurges of fluid.

Historical data from actual plant heatup and cooldown cycles from startup to 1994 were reviewed to more accurately account for early plant operation. Using this data, and assuming projected plant heatup and cooldown cycles, the expected CUF for the limiting (heater penetration) location was determined as significantly less than 1.0. The analysis demonstrated acceptable structural integrity for these pressurizer locations for a 60 year projected life of the plant. The projected combined fatigue usage factors (including insurge/outsurge) for the three bounding locations are shown in the PBNP LRA Table 4.3.5-1, Pressurizer Lower Head Fatigue Results Including Insurge/Outsurge. The most limiting Units 1 and 2 CUF was determined as 0.057 for a heater penetration. The applicant also stated that, for confirmatory purposes, the Fatigue Monitoring Program will monitor fatigue usage at the fatigue-sensitive locations during the period of extended operation.

Each pressurizer is classified as Seismic Category I, requiring that there be no loss of function in the event of the assumed maximum potential ground acceleration in the horizontal and vertical directions simultaneously, when combined with the primary steady state stresses.

The pressurizer is described in FSAR Sections 4.1, Reactor Coolant System, Design Basis, and 4.2, RCS System Design and Operation.

In addition to the basis described in the regulatory evaluation, Section 2.2.2 above, the PBNP pressurizer and supports have been evaluated for plant license renewal. The intended functions are pressure boundary, structural support and closure integrity. The subcomponents of the pressurizer that require Aging Management Review (AMR) include the lower head, surge nozzle, surge nozzle safe end, heater well and heater sheath, shell, instrument nozzle thermal wells, upper head, spray nozzle and safe end, relief nozzle and safe end, manway cover, support skirt and flange, and manway cover bolts.

The WOG issued Generic Topical Report WCAP-14754-A, License Renewal Evaluation: Aging Management Evaluation for Pressurizers, to address the aging management of pressurizers. Also, the NRC staff issued License Renewal Safety Evaluation Report (SER) for the Point Beach Nuclear Plant Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 5). Details of the PBNP AMR are provided in FSAR Chapter 15, Aging Management Programs and Time Limited Aging Analysis.

2.2.2.7.2 Technical Evaluation

Input Parameters, Assumptions and Acceptance Criteria

Input parameters

The reactor vessel outlet (T_{hot}) and reactor vessel inlet (T_{cold}) temperatures define the normal operating temperatures for the surge and spray lines to the pressurizer, respectively. The reactor coolant pressure defines the pressurizer normal operating pressure (2250 psia) and saturation temperature (652.7°F). The minimum values of T_{hot} and T_{cold} in LR Section 1.1, Nuclear Steam Supply System Parameters are used in the pressurizer evaluations in order to maximize the difference between the surge and spray line temperatures and saturation temperature.

The pressurizer temperature and pressure variations, surge line flow rates, reactor vessel T_{hot} and T_{cold} for the NSSS design transients are applicable to the pressurizer.

The EPU NSSS parameters are in LR Section 1.1. The NSSS EPU design transients in LR Section 2.2.6, NSSS Design Transients, provide the operating and transient conditions that differ from those to which the PBNP Units 1 and 2 pressurizers were previously designed and analyzed.

Assumptions

Unless indicated otherwise, the transients are assumed to be initiated with the pressurizer at the normal conditions for power operation, that is, saturation at 2250 psia. The water and steam volumes are assumed to be saturated liquid and saturated vapor, respectively, and the temperature is approximately 653°F.

Where pressurizer water temperature and/or steam temperature curves are not provided, these parameters are assumed to be the saturation temperature for the existing pressurizer pressure.

The relatively stagnant water normally in the spray piping is swept through the piping and into the pressurizer ahead of the spray flow from the cold leg. The temperature of this stagnant water is assumed to be T_{cold}.

Step temperature changes are assumed for components in contact with the spray and surge line insurges.

Seismic analyses and non-pressure boundary component evaluations are not affected by the EPU.

Acceptance Criteria

Assessing the acceptability of EPU parameters affecting the pressurizer stress reports first involved comparing the EPU parameters with the design inputs considered in the stress reports. The EPU parameters are acceptable if the following criteria are met:

1. Hot and cold leg temperatures remain within the temperature ranges previously considered and justified in the pressurizer stress reports.

2. NSSS design transients are bounded by the design transients previously considered in the pressurizer stress reports in severity and number of occurrences. Additionally, no NSSS design transients not previously considered are identified. The pressurizer temperature and pressure variations for each transient were considered in this comparison review to determine the relative severity of the revised design transients compared to the existing design transients.

3. Design loads are less than or equal in magnitude to the loads that were previously considered in the pressurizer stress reports with no changes to the load application points and numbers of occurrences.

If comparison of the EPU design inputs to the design inputs considered in the pressurizer stress reports revealed hot and/or cold leg temperatures, NSSS design transients or design loads that do not comply with the above criteria, then pressurizer structural analyses and evaluations were performed as necessary to address the EPU design inputs. The acceptance criterion for these evaluations and analyses is that the PBNP Units 1 and 2 pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III, 1965 Edition with Addenda through Summer, 1966 for plant operation in accordance with the EPU.

Description of Analyses and Evaluations

Analysis was performed by modifying results from the original PBNP Units 1 and 2 pressurizer stress reports which were performed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, Summer 1966 Addendum. Analytical models of various sections of the pressurizer were subjected to pressure loads, external loads (such as piping loads), and thermal transients.

The input parameters associated with the PBNP EPU were reviewed and compared to the design inputs considered in the current pressurizer stress reports. In cases where revised input parameters did not meet the above acceptance criteria, pressurizer structural analyses and evaluations were performed. Impacts on the existing design basis analyses were determined by applying scaling factors developed through a comparative analysis of EPU inputs to design inputs considered in the pressurizer stress reports. This method involves a simplified engineering approach using the existing analyses as the basis of the evaluation. Scaling factors were used to assess the impact of parameters such as the system transients, temperatures, and pressures. New stresses and revised cumulative usage factors (CUF) were calculated, as applicable, and compared to previous results. The evaluation results were then compared with the ASME Code, Section III, 1965 Edition, Summer 1966 Addendum to confirm that allowable limits are met.

The Pressurizer is a bottom-skirt supported vessel. The Pressurizer is supported on heavy concrete slab spanning the concrete shield walls of its compartment. The bottom-skirt is supported by 24-1 1/2" diameter anchor bolts (A36).

The primary equipment pressurizer support of the nuclear steam supply system (NSSS) as described in the PBNP Final Safety Analysis Report (FSAR) in Section 4.2, and Appendix A.5 were evaluated for the EPU. The pressurizer bottom-skirt support loads due to the parameters associated with the EPU were reviewed for impact on the existing pressurizer bottom-skirt support design.

The acceptance criteria for PBNP, for the pressurizer support is contained in the American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, Eighth Edition.

The pressurizer supports were evaluated against the acceptance criteria for PBNP as used in the current design basis and the American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, Eighth Edition.

Evaluation of Impact on Renewed Plant Operating License Renewal Programs

The pressurizer performs the intended function of ensuring the integrity of the reactor coolant pressure boundary.

The WOG generic topical report on pressurizer aging management, WCAP-14574-A, (Reference 6) concluded that the only effect that required utility action is fatigue. The aging effects of irradiation embrittlement, thermal aging, erosion and erosion/corrosion, wear, and creep and stress relaxation have been determined to not be detrimental to the pressurizer at the current operating or at the EPU conditions. There are no pressure boundary materials in the pressurizer subject to thermal aging embrittlement, erosion, and mechanical wear. For creep and stress relaxation, the temperature during all plant conditions is well below the 1000°F limit of concern reported in Table 3-2 of WCAP-14574-A (Reference 6). The potential effects of SCC/PWSCC and boric acid corrosion can be managed by current industry programs. The only Time-Limited Aging Analysis for the pressurizer is fatigue.

As discussed in the License Renewal SER (NUREG-1839 Reference 5), PBNP provided calculated fatigue CUF values for key pressurizer components in response to RAI 4.3.5-5, In all cases, the cumulative fatigue usage values remained below 1.0 for the period of extended operation, including the insurge/outsurge transients. Consistent with Table 2.2.2.7-1, the limiting component was the spray nozzle.

The environmental fatigue effect was incorporated into separate fatigue evaluations using real-time plant operational transient data using the EPRI Fatigue Pro software monitoring software. These environmental CUFs were less than the ASME Code Section III Class 1 fatigue limit of 1.0. The NRC staff evaluation of environmental effects on the pressurizer lower head and surge nozzle is contained in Section 4.3.10 of the License Renewal SER (NUREG-1839).

The NRC staff concluded that the PBNP evaluation of pressurizer metal fatigue complies with staff's requirements and assures adequate safety margins through the extended period of operation.

The evaluations for EPU confirm that the conclusions reached in NUREG-1839 (Reference 5) for pressurizer fatigue and the pressurizer support remain valid for the EPU.

2.2.2.7.3 Results

The analysis shows that the PBNP Units 1 and 2 EPU transients will have a limited effect on the pressurizer components. Note the pressurizer surge line evaluation is documented in the LR Section 2.2.2.1, NSSS Piping, Components and Supports.

Most of the pressure fluctuations during the revised design transients (LR Section 2.2.6, NSSS Design Transients) are the same as, or are enveloped by, the pressures in the original evaluations. There were small increases in maximum pressure during the Large Step Load Decrease transient and the Loss of Load transient. These increases remain within the limit for Upset Conditions (within 110% of design pressure) and, therefore, are acceptable. The design primary stress evaluation still envelops the Upset primary stress evaluation. The maximum pressure within the Normal, Faulted, and Test categories has not changed from the value used in the original evaluations. Thus, the revised transients have no effect on the primary stress evaluations performed previously.

Analyses demonstrate that fatigue usage and primary plus secondary stress intensity ranges for pressurizer components and pressurizer supports meet ASME Code acceptance criteria for EPU. Fatigue and stress analysis results are provided in Tables 2.2.2.7-1 and 2.2.2.7-2.

PBNP Unit 1 and 2 pressurizer supports were evaluated for EPU and were found acceptable. Table 2.2.2.7-3 lists the critical component.

2.2.2.7.4 Conclusions

Critical components of the PBNP Units 1 and 2 pressurizers and supports were evaluated for operation at EPU conditions. Based on these evaluations, it is concluded that pressurizer components meet the stress intensity/fatigue requirements of the ASME Code Section III, 1965 Edition with Addenda through Summer, 1966 for all proposed EPU operation. The pressurizer support is found acceptable using the AISC, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, Eighth Edition criteria. The pressurizer and pressurizer supports continue to meet the current licensing basis with respect to PBNP GDCs 1, 2, 9,and 40. Therefore, PBNP finds the proposed EPU acceptable with respect to the pressurizer and supports.

2.2.2.7.5 References

1 NRC Bulletin (BL) 88-11, Pressurizer Surge Line Thermal Stratification, December 20, 1988

2 WCAP-13509, Structural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge Lines, Considering The Effects of Thermal Stratification", October 1992

3. WCAP-13510, Strucural Evaluation of the Point Beach Units 1 & 2 Pressurizer Surge LInes, Considering The Effects of Thermal Stratification, October 1992

4. WCAP-13588, Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients, dated March 1988

5. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

6. WCAP-14575, Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, dated December 2000

Table 2.2.2.7-1
PBNP Units 1 and 2 Fatigue Usage Comparisons

Component	Revised Fatigue Usage	Previous Fatigue Usage
Spray Nozzle	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Upper Head	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Surge Nozzle	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Safety and Relief Nozzle	[ ]$^{c,e)}$	[ ]$^{(c,e)}$
Support Skirt and Flange	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Lower Head	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Heater Well	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Manway	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Instrument Nozzle	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$
Immersion Heater	[ ]$^{(c,e)}$	[ ]$^{(c,e)}$

Table 2.2.2.7-2
PBNP Units 1 and 2 Primary plus Secondary Stress Intensity Ranges

Component	Calc./Allow*
Spray Nozzle	[ ](c,e)
Upper Head	[ ](c,e)
Surge Nozzle	[ ]c,e)
Safety and Relief Nozzle	[ ](c,e)
Support Skirt and Flange	[ ](c,e)
Lower Head	[ ](c,e)
Heater Well	[ ](c,e)
Manway	[ ](c,e)
Instrument Nozzle	[ ](c,e)
Immersion Heater	[ ]c,e)

* Ratio of calculated to allowable stress intensity.

1. Quantity shown is the ratio of stress intensity range, with thermal bending removed, to the allowable. The range of primary plus secondary stress intensity exceeded the $3S_m$ limit, but this is permitted, provided the rules of NB-3228.3 of the ASME Code are met. Those requirements have been satisfied for this component.

Table 2.2.2.7-3
RCL Primary Equipment Pressurizer Support Anchor Bolts Stresses Percent of Allowable = (Actual/Allowable) x 100%

Member	Upset		Faulted	
	Allowable	Stress Ratio, %	Allowable	Stress Ratio, %
Anchor Bolts	(Note 1)	(Note 1)	4.5 ksi(2)	[ ] b,c

Notes
1. Faulted case governs.
2. Allowable stress is calculated based on the AISC, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," Eighth Edition.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

2.2.3.1 Regulatory Evaluation

Reactor pressure vessel (RPV) internals consist of all the structural and mechanical elements inside the reactor vessel, including core support structures. PBNP 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 loss-of-coolant accidents (LOCAs), and the identification of design transient occurrences. PBNP's review covered the analyses of flow-induced vibration (FIV) for safety-related and nonsafety-related reactor internal components, as well as the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. PBNP's review also included a comparison of the resulting stresses and cumulative fatigue usage factors against the corresponding Code-allowable limits. NRC's acceptance criteria were 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 10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences

Specific review criteria are contained in the SRP, Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5 and guidance provided in Matrix 2 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 1, 2, 4 and 10 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

All piping, components and supporting structures of the Reactor Coolant System are designed as seismic Class I equipment. Seismic Design Classification details are given in FSAR Appendix A.5, Seismic Design Analysis.

The Reactor Coolant System is located in the containment building whose design, in addition to being a Seismic Class I structure, also considers accidents or other applicable natural phenomena.

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

As stated in FSAR Section 3.1, Reactor, Core Design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations.

The adequacy of the PBNP reactor pressure vessel internals and core supports are described in FSAR Chapter 1 Sections 1.3.1, Overall Plant Requirements, 1.3.2, Protection by Multiple Fission Product Barriers, 1.4, Quality Assurance Program, Chapter 3 Sections 3.1.2, Principle Design Criteria, 3.1.3, Safety Limits, 3.2.3, Mechanical Design and Evaluation, Chapter 4 Sections 4.1, Reactor Coolant System, Design Basis, 4.2, RCS System Design and Operation, 4.4, Tests and Inspections, and Chapter 15 Section 15.2.17, Reactor Vessel Internals Program.

In addition to the evaluations described in the FSAR, the PBNP reactor internals components were evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 6)

The reactor pressure vessel internals and core support structural components are discussed in the License Renewal SER in Section 3.1.

2.2.3.2 Technical Evaluation

2.2.3.2.1 Introduction

The RPV internal system consists of the reactor vessel, reactor internals, fuel, and control rod drive mechanisms (CRDMs). The reactor internals functional description is provided below. The reactor internals are designed to withstand forces due to normal, upset, emergency, and faulted conditions.

Changes in the primary coolant system operating conditions (e.g., increase in power) also produce changes in the boundary conditions; this includes loads and temperatures experienced by the reactor internal components. Ultimately, this results in changes in the stress levels in these components and changes in the relative displacement between the reactor vessel and the reactor internals. To ensure that the reactor internal components still maintain their design functions, and to ensure safety questions have been reviewed, a systematic evaluation of the reactor components has been performed to assess the impact of increased core power on the reactor internal components. The reactor internal core support structure is defined as follows:

Upper Core Support Assembly (consisting of the following components)

- Upper support plate/deep beam structure
- Upper core plate
- Upper core plate fuel pins
- Upper support columns

Lower Core Support Assembly (consisting of the following components)

- Lower support plate
- Lower core plate
- Lower core plate fuel pins
- Lower support columns
- Core barrel assembly
- Baffle-former assembly
- Radial keys and clevis insert assembly

- Upper core plate alignment pin

The internal structures are defined as all those other structures within the reactor vessel that are not core support structure, fuel assemblies, control assemblies, and instrumentation. These structures are attached to and supported by the core support structure.

Reactor Internals Functional Description

The reactor internals core support structure is within the confines of the reactor vessel. The function of the structure is to provide the direct support and restraint of the core, i.e., fuel assemblies. The core support, together with the internal structures, provides:

- The orientation of the reactor core
- The orientation, guidance, and protection of the reactor control rod assemblies
- A passageway for directional and metered control of the reactor coolant flow through the reactor core
- A passageway, support, and protection for any in-vessel/core instrumentation
- A secondary core support for limiting the downward displacement of the core support structure in the event of a postulated failure of the core-barrel assembly
- Reactor vessel neutron shielding

Function of Core Support Structure

Upper Core Support Assembly

The upper core support assembly provides the vertical and lateral restraint and lateral alignment of the top of the core through its primary components (upper support plate/deep beam structure, support columns, and the upper core plate) and its interface with the reactor vessel. The assembly also provides the support for the internals structures, such as the instrumentation conduit and supports, and reactor control rod guide tubes.

The upper support subassembly, which is supported on its outer edges, transfers the loading of the upper core support assembly to the reactor vessel. Keyways, with customized inserts to maintain required gaps, are located in the outer edges of the subassembly to provide the upper-core-support-assembly to reactor vessel to lower-core-support assembly alignment, and to limit any transverse or rotational movement of the subassembly. There are penetrations through the subassembly for spray nozzles that allow limited flow into the reactor vessel upper head region.

The upper support columns transfer vertical and lateral loads to the upper support subassembly and support the upper core plate vertically. Guides are provided at the lower end of the upper columns for coolant flow.

The upper core plate, which is attached to the bottom of the upper support columns, forms the upper periphery of the core, transfers core loading to the support columns, and, when in place within the reactor vessel, rests on the fuel assembly springs causing the core preload. The plate is perforated to allow coolant flow while maintaining a uniform velocity profile. The underside of the upper core plate contains the upper fuel pins, which engage the top of the fuel assemblies.

The upper-core-periphery to lower-core-periphery alignment is provided through keyways in the outer edges of the upper core plate that contain customized inserts that provide the required pin engagement gaps. In addition, the keyway/insert system limits any rotation or translation of the upper core plate.

Lower Core Support Assembly

The lower core support assembly is the major supporting assembly of the total structure. The assembly functions to:

- Support the core and the attached internal structures
- Transfer these and other design loadings to the reactor vessel
- Provide the restraint and alignment of the core
- Provide the directional and metered control of the reactor coolant flow through the core
- Provide neutron shielding for the reactor vessel

Fuel assemblies are placed into the core-barrel subassembly and rest on the lower core plate. The lower core plate, is supported on the lower core barrel ledge and by the lower support columns, and contains the lower fuel pins that provide location and alignment for the bottom of the fuel assemblies. The lower core plate is perforated to allow directional and metered control of flow of the reactor coolant and is attached to the core barrel and the flange, forming the core barrel subassembly. The function of the core barrel subassembly is to transmit the loading to the reactor vessel. This is accomplished at the top by the core-barrel flange, which rests on a ledge provided on the reactor vessel and limited loading is transmitted at the bottom by the radial support system.

The radial support system consists of keys that are attached to the lower end of the core barrel subassembly on the lower support plate and that engage clevises provided in the reactor vessel. This system restricts the lower end of the core-barrel subassembly from rotational or tangential movement, but allows for radial thermal growth and axial displacement.

Inside the core barrel, above the lower support plate, is the baffle-former assembly. This assembly forms a radial periphery of the core and, through the dimensional control of the cavity, i.e., the gap between the fuel assemblies and baffle plates, provides directional and metered control of the reactor coolant through the core.

2.2.3.2.2 Input Parameters, Assumptions and Acceptance Criteria

The principal input parameters utilized in the analysis of the reactor internal components and core supports are the reactor coolant system (RCS) design parameters provided in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. For structural analysis/evaluations, the nuclear steam supply system (NSSS) design transients discussed in LR Section 2.2.6, NSSS Design Transients, were considered. The fuel considered is a full core of Westinghouse 14x14 422 V+ fuel without intermediate flow mixing (IFM) grids with the thimble plugging devices removed.

There are no assumptions as part of these evaluations/analyses.

Reactor Internals Heat Generation

The presence of radiation-induced heat generation rates in the reactor internals components, in conjunction with the reactor coolant fluid temperatures, results in thermal gradients within and between the components. The resultant material temperature gradients cause thermal stresses and thermal growth that must be considered in the design and analysis of the various components. The primary design considerations are to ensure that thermal growth is consistent with the functional requirements of the components and to ensure that the applicable ASME Code requirements are satisfied as part of the components evaluation.

The reactor internals components subjected to significant radiation-induced heat generation are the core baffle plates, former plates, core barrel, baffle-former bolts, barrel-former bolts, thermal shield, and the upper and lower core plates. However, due to the relatively lower heat generation rates in the thermal shield materials, this component experiences little, if any, temperature rise relative to the surrounding reactor coolant.

This section provides a description of the methodology that is used to determine the radiation-induced heat generation rates in the internals components and provides the results of the evaluation assessing the impact of the PBNP Units 1 and 2 core power uprate to 1800 MWt on these heating rates. The current evaluation included the impact on heat generation rates in the core baffle, barrel, thermal shield, and the upper and lower core plates. The impact on the heat generation rates applicable to the core formers is inferred from the data generated for the core baffle and barrel.

Description of the Evaluation of Heat Generation Rates

The initial design of the PBNP Units 1 and 2 reactor internals was based on a reactor core operating at 1518.5 MWt with spatial core power distributions designed to produce conservative results for components in radial locations outboard of the reactor core (baffle plates, barrel, and thermal shield) as well as for the core components located above and below the core (upper and lower core plates). These baseline heat generation rates were documented in WCAP-9620, Revision 1 (Reference 3).

Over time, it was noted that, in general, the heat generation rates calculated for the radial components remained conservative. One of the primary reasons for this observation is that the tendency within the industry to transition from out/in fuel management to low leakage core designs has resulted in greatly reduced heat generation at the core periphery which, in turn, has provided significant margin relative to the calculated design heating rates. For the core plates, however, evolving fuel assembly designs and core operation resulted in a tendency toward increased heating rates in these axial components. As a result, a new set of conservative heat generation rates were calculated for use in the assessment of upper and lower core plate structural integrity. These updated values were intended to supersede the core plate data provided in Reference 3 and to establish a new baseline for upper and lower core plate structural analysis.

For the evaluation of the PBNP Units 1 and 2 radial internals components at the uprated core power of 1800 MWt, it was anticipated that, due to the implementation of low leakage fuel cycle designs, the heating rates used in the original analysis would remain bounding at the uprated core power. To test this hypothesis, a set of heat generation rates based on the projected uprate fuel management strategy was calculated and the results compared directly with the corresponding data provided in Reference 3. The results of this comparison are discussed in Section 2.2.3.2.2, Input Parameters, Assumptions and Acceptance Criteria. The heat generation rate calculation for the radial components was completed using the DORT two-dimensional discrete ordinates code from the DOORS 3.2 Code Package (Reference 4). This suite of codes has been used to support numerous pressure vessel fluence evaluations and is accepted by the NRC for deterministic particle transport calculations. The transport cross-sections used in the calculations were taken from the BUGLE-96 coupled neutron/photon cross-section library (Reference 5) that was generated specifically for Light Water Reactor (LWR) applications.

In the case of the PBNP Units 1 and 2 radial internals, two sets of heating rate calculations were completed in order to accurately model the components being evaluated. The core baffle plates were analyzed using an x,y geometric model and the core barrel and thermal shield heating rates were determined using an r,θ geometry. All of the transport calculations used a P_5 expansion of the neutron scattering cross-sections and an S_{16} order of angular quadrature.

For the evaluation of the upper and lower core plates, no additional calculations were required. The data supplied in a previous generic evaluation as the updated baseline for axial component heating represent a bounding and conservative situation relative to both core power level and axial core power distribution. In the generic analysis for the 2-Loop internals designs, the assumed core power level was 2050 MWt and the axial distribution of core power was assumed to be uniform throughout the reactor core. Thus, the core power assumption in the baseline data exceeds that of the PBNP Units 1 and 2 uprate conditions by several hundred megawatts and, in addition, the assumption of a uniform axial power distribution increases the leakage from the top and bottom of the reactor core relative to any realistic core operating conditions.

Results of the Evaluation of Heat Generation Rates

The results of the radiation-induced heat generation rate evaluations are provided in Table 2.2.3-4, Comparison of Original Zone Average Heating Rates with Current Analysis, through Table 2.2.3-6, Spatial Distribution of Long-Term Heating Rates in the Lower Core Plate Reactor Power = 2050 MWt. In Table 2.2.3-4, a comparison of the radial component heating rates applicable to the PBNP Units 1 and 2 reactors operating at 1800 MWt with the corresponding data from Reference 3 is provided. This comparison shows that for all of the radial components significant margin exists between the EPU calculations and the original design values. The applicable heating rates for the upper and lower core plates are provided in Table 2.2.3-5, Spatial Distribution of Long-Term Heating Rates in the Upper Core Plate Reactor Power = 2050 MWt, and Table 2.2.3-6, Spatial Distribution of Long-Term Heating Rates in the Lower Core Plate Reactor Power = 2050 MWt, respectively. This was taken directly from a previous generic evaluation and represents bounding heat generation rates for the upper and lower core plates.

Evaluations/analyses

PBNP has performed evaluations/analyses to assess the effect of operating at 1800 MWt on the reactor pressure vessel/internals system of the PBNP. The description of these analyses and evaluations are provided in the following sections, which form the bases for the "Acceptance Criteria" given below.

Acceptance Criteria

- The design core bypass flow limit with the thimble plugging devices removed is 6.5% of the total vessel flow rate
- The RCCA drop time Technical Specification of 2.2 seconds is to be maintained
- For the structural and fatigue evaluations of core support components, the components stresses meet the allowable stress limits and the cumulative fatigue usage factors must be less than 1.0

2.2.3.2.3 Description of Analyses and Evaluations

The reactor vessel internals have been analyzed for the PBNP EPU revised design parameters and the design basis load combinations. The analysis of the components was performed for the normal, upset, emergency and faulted conditions (LOCA/Seismic). The results of these analyses confirm that there is no adverse impact on the structural adequacy of the reactor internals components for the EPU conditions.

In addition to the evaluations described above, the PBNP reactor internals components were evaluated for plant license renewal. System and system component materials of construction, operating history and programs used to manage aging effects are described and documented in NUREG-1839, Safety Evaluation Report (SER) Related to the License Renewal of the Point Beach Nuclear Plant Units 1 and 2, December 2005 (Reference 6).

Thermal-Hydraulic System

System Pressure Losses

The principal RCS flow route through the RPV system at PBNP begins at the inlet nozzles. At this point, flow turns downward through the reactor vessel/core-barrel annulus. After passing through this down-comer region, the flow enters the lower reactor vessel dome region. This region is occupied by the internals energy absorber structure, lower support columns, bottom-mounted instrumentation columns, and supporting tie plates. From this region, flow passes upward through the lower core support plate, and into the core region. After passing up through the core, the coolant flows into the upper plenum, turns, and exits the reactor vessel through the outlet nozzles. Note that the upper plenum region is occupied by support columns and rod cluster control assembly (RCCA) guide columns.

A key area in evaluation of core performance is the determination of hydraulic behavior of coolant flow within the reactor internals system, i.e., vessel pressure drops, core bypass flows, RPV fluid temperatures and hydraulic lift forces. The pressure loss data is necessary input to the LOCA and non-LOCA safety analyses and to overall NSSS performance calculations. The hydraulic forces are considered in the assessment of the structural integrity of the reactor internals, core clamping loads generated by the internals hold-down spring, and the stresses in the reactor vessel closure studs.

Thermal hydraulic evaluations were performed by solving the mass and energy balances for the reactor internals fluid system. These analyses determined the distribution of pressure and flow within the reactor vessel, internals, and the reactor core. Results were obtained with a full core of Westinghouse 14x14 422 V+ fuel without IFM grids with the thimble plugging devices removed, and at RCS conditions, as given in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1.

Core Bypass Flow

Bypass flow is the total amount of reactor coolant flow bypassing the core region and is not considered effective in the core heat transfer process. Variations in the size of some of the bypass flow paths, such as gaps at the outlet nozzles and the core cavity, occur during manufacturing or change due to fuel assembly changes. Plant-specific, as-built dimensions are used in order to demonstrate that the bypass flow limits are not violated. Therefore, analyses are performed to estimate core bypass flow values to either show that the design bypass flow limit for the plant will not be exceeded or to determine a revised design core bypass flow.

Fuel assembly hydraulic characteristics and system parameters, such as inlet temperature, reactor coolant pressure, and flow were used to determine the impact of EPU RCS conditions on the total core bypass flow. The results of this analysis calculated a best estimate core bypass flow value of 5.12% with the thimble plugging devices removed. Therefore, the design core bypass flow value of 6.5% with thimble plugging devices removed remains acceptable.

Hydraulic Lift Forces

An evaluation was performed to estimate hydraulic lift forces on the various reactor internal components for the EPU parameters shown in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. This is done to show that the reactor internals assembly would remain seated and stable. Based on the evaluation performed for EPU, the reactor internals will remain seated and stable for the EPU RCS normal operating conditions. The core barrel ledge contact loads of 1.5E+05 lbf (Unit 1) and 1.7E+05 lbf (Unit 2) exceeds the minimum allowable load of 1.0E+05 lbf for the reactor internals to remain seated and stable. These loads were conservatively calculated assuming no hold-down contribution from the fuel assemblies and increased spring relaxation.

Upper Head Region Fluid Temperatures

The average temperature of the primary coolant fluid that occupies the reactor vessel closure head volume is an important initial condition for certain dynamic LOCA analyses. Therefore, it was necessary to determine the upper head temperature when changes in the RCS conditions take place in the plant. Determination of upper head temperature stemmed from the THRIVE evaluations used to assess the core bypass flow. The THRIVE code models the interaction between all different flow paths into and out of the closure head region. Based on this interaction, it calculates the core bypass flow into the head region and average head fluid temperature for different flow path conditions. PBNP is configured such that the upper head region is at slightly below T_{hot}. These upper head temperatures were provided as inputs and were used in subsequent LOCA analyses.

RCCA Scram Performance

The RCCAs represent perhaps the most critical interface between the fuel assemblies and the other internal components. It is imperative to show that the EPU RCS conditions will not adversely impact the operation of the RCCAs, either during accident conditions or normal operation.

The analysis performed determined the potential impact of the conditions shown in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1 on the limiting RCCA drop time. The maximum estimated RCCA drop time was calculated to be 2.19 seconds to the top of dashpot including all uncertainties, which is still less than the current Technical Specification limit of 2.2 seconds.

Mechanical System

LOCA Loads

To perform the RPV LOCA analyses of PBNP, a finite element model of the RPV system was developed. The mathematical model of the RPV is a three-dimensional, nonlinear finite element model that represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model was developed using the WECAN code, a general purpose, finite element computer code that has been used for this analysis since the original plant design. For the EPU LOCA analyses were performed to generate core plate motions and the reactor vessel/internals interface loads. Because larger lines are to be excluded by leak-before-break methodology (see LR Section 2.1.6, Leak-Before-Break), the largest branch lines considered in this EPU analysis were the 3" Schedule 160 charging line break (cold leg or CLBRK) and 6" Schedule 120 capped line break (hot leg or HLBRK). Of these two breaks, the 6-inch schedule 120 capped line break (hot leg of HLBRK) was found to be more limiting.

The results of LOCA reactor vessel displacements and the impact forces calculated at vessel/internals interfaces are used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions for both breaks were used in fuel grid crush analysis and to confirm the structural integrity of the fuel as discussed in detail in LR Section 2.8.1.2.3, Seismic/LOCA.

Seismic Analyses

The EPU does not impact the seismic response of the reactor internals; however, due to the changes in vessel support stiffness which was much smaller than previously used, a nonlinear time history seismic analyses of the RPV system was performed. This analysis included the development of the system finite element model and the synthesized time history accelerations.

The results of the system seismic analysis include time history displacements and impact forces for all the major components. The reactor vessel seismic displacements and the impact forces calculated at vessel/internals interfaces are used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions were used in fuel grid crush analysis and to confirm the structural integrity of the fuel as discussed in detail in LR Section 2.8.1.2.3, Seismic/LOCA.

Flow-Induced Vibrations

Flow-induced vibrations (FIV) of pressurized water reactor internals have been studied for a number of years. The objective of these studies is to show the structural integrity and reliability of reactor internal components. These efforts have included in-plant tests, scale-model tests, as well as tests in fabricators' shops and bench tests of components, along with various analytical investigations. The results of these scale-model and in-plant tests indicate that the vibrational behavior of Westinghouse two-, three-, and four-loop plants is essentially similar, and the results obtained from each of the tests complement one another and make possible a better understanding of the FIV phenomena. Based on the analysis performed for the PBNP, reactor internals response due to FIV is extremely small and well within the allowable based on the high cycle endurance limit for the material. The results of FIV analyses due to EPU at PBNP are provided in Table 2.2.3-1, Lower Internal Critical Component Stresses Due to FIV –Thermal Shield (TS) PBNP Units 1 and 2 EPU Conditions, and Table 2.2.3-2.

Reactor Pressure Vessel Internals and Core Support Structure Components

In addition to supporting the core, a secondary function of the reactor vessel internals assembly is to direct coolant flows within the vessel. While directing primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and the internals structural components. Some of the parameters influencing the mechanical design of the internals lower assembly are the pressure and temperature differentials across its component parts and the flow rate required to remove heat generated within the structural components due to radiation (for example, gamma heating). The configuration of the internals provides adequate cooling capability. Also, the thermal gradients resulting from gamma heating and core coolant temperature changes are maintained below acceptable limits within and between the various structural components.

The PBNP reactor internals were designed and built prior to the implementation of Subsection NG of the ASME Code, and therefore, a plant-specific stress report on the reactor internals was not required. The structural integrity of the PBNP reactor internals design has been ensured by analyses performed on both generic and plant-specific bases to meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical PBNP reactor internal components for EPU RCS conditions and revised NSSS design transients.

Structural evaluations demonstrate that the structural integrity of reactor internal components is not adversely affected either directly by the EPU RCS conditions and NSSS design transients, or by secondary effects on reactor thermal-hydraulic or structural performance. Heat generated in reactor internal components, along with the various fluid temperature changes, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth, which must be considered in the design and analysis of the various components.

Component Analyses/Assessments

A series of evaluations/assessments for the PBNP were performed on reactor internal components for the EPU conditions. The most critical components that were evaluated are:

- Upper support plate/deep beam structure
- Upper core plate
- Upper core plate fuel pins
- Upper support column
- Lower support plate
- Lower core plate
- Lower support column
- Core barrel
- Radial keys and clevis insert assembly
- Baffle-former assembly

The results of these evaluations/assessments demonstrate that the above listed components are structurally adequate for the EPU conditions and the fatigue usage factors were less than 1.0. A summary of stresses versus allowable and corresponding fatigue usage factors is given in Table 2.2.3-3, Reactor Internal Components Stresses and Fatigue Usage Factors PBNP Units 1 and 2 EPU Conditions.

Baffle-Former Bolts

The bolts are evaluated for loads resulting from hydraulic pressure, seismic and LOCA loads, preload, and thermal conditions. The temperature difference between baffle and barrel produces the dominant loads on the baffle-former bolts and the loads that are most directly affected by the uprating. The EPU RCS conditions do not affect deadweight or preload forces and do not increase the seismic or LOCA loads on the bolts.

This evaluation has determined that baffle-former bolts remain acceptable for the license renewal extended period of operation at EPU conditions. The following summarizes the basis for this determination:

- Extended operation for a 60-year design life is acceptable based on the determination that 3,545 cycles of the plant loading and unloading design transient were qualified with 3,545 of these cycles at the EPU RCS conditions. This loading controls the fatigue life of the baffle-former bolts. All other design transients, except plant loading and unloading, listed in the FSAR, Table 5.1-4, or generated for the EPU RCS conditions were qualified for the specified number of cycles. In order to comply with the requirements of 10 CFR 54.21(c)(1)(iii), a Fatigue Monitoring Program is implemented at PBNP to ensure that the number of design cycles will not be exceeded during the period of extended operation.

This evaluation has taken into consideration that Unit 2 has replaced a portion of baffle bolts and Unit 1 uses the original bolts as intact. The fact remains that both Units have some original bolts as used in the analysis.

- Evaluation of environmental fatigue effects is not required for the baffle-former bolts

2.2.3.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

This LR section addresses the maximum stress intensity ranges and cumulative fatigue damage for critical reactor vessel internal components considering the impact of EPU conditions on license renewal and evaluates those ranges and fatigue damage against the ASME Code limits. Stress corrosion cracking (SCC) of RPV internals components is addressed in LR Section 2.1.5, Reactor Coolant Pressure Boundary Materials.

The evaluations (summarized in this section) of maximum stress intensity ranges and cumulative fatigue usage factors for the components of the reactor vessel internals, considering EPU conditions, show that the reactor vessel components continue to meet the ASME acceptable limits. Since the original 40-year design transient set has been shown to be bounding for 60 years of operation based on the finding that the number of original design cycles bounds the actual plant cycles, and the number of design cycles for the EPU has not changed from the original 40-year transient set, the fatigue evaluations of the reactor vessel internals components are valid for 60 years of operation.

Finally, the current ASME Section XI Inservice Inspection Program is considered to provide reasonable assurance that aging effects will be managed such that the intended functions of reactor pressure vessel (RPV) internal components will be maintained during the license renewal period. The NRC staff concluded that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of structure and components subject to an aging management review such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis, as required by 10 CFR 54.29(a).

In addition, as part of the License Renewal efforts, PBNP committed to submit an enhanced reactor vessel internals aging management program prior to the period of extended operation. The reactor internals program is anticipated to be modeled in accordance with current efforts now being developed by the industry through the EPRI Materials Reliability Program (MRP) Issues Task Group (ITG).

PBNP has evaluated the impact of the EPU on the conclusions reached in the PBNP License Renewal Application for the reactor vessel internals. The aging evaluations approved by the NRC in NUREG-1839 (Reference 6) for the reactor vessel internal components remain valid for EPU conditions.

2.2.3.3 Results

Analyses have been performed to assess the effect of changes due to EPU at PBNP. The various results reached are as follows:

- The design core bypass flow value of 6.5% of the total vessel flow with thimble plugging devices removed is maintained for the EPU conditions
- An RCCA performance evaluation was completed and the results indicated that the current 2.2-second RCCA drop-time-to-dashpot entry limit (from gripper release of the drive rod) is satisfied at the EPU conditions
- Evaluations of the critical reactor internal components were performed, which indicated that the structural integrity of the reactor internals is maintained at the EPU conditions and the cumulative fatigue usage factors were all shown to be less than 1.0

The results of component structural analyses are summarized in Table 2.2.3-3, Reactor Internal Components Stresses and Fatigue Usage Factors PBNP Units 1 and 2 EPU Conditions.

2.2.3.4 Conclusions

PBNP has reviewed the evaluations related to the structural integrity of reactor pressure vessel internals and core supports and concludes that the evaluations have adequately addressed the effects of the proposed EPU on the reactor pressure vessel internals and core supports. PBNP further concludes that the evaluations have demonstrated that the reactor pressure vessel internals and core supports continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1, 2, and 6 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the design of the reactor pressure vessel internals and core supports.

2.2.3.5 References

1. ASME Section III, Division 1, 1998 Edition with 2000 Addenda, Code Section NB-3222
2. ASME Section III, Division 1, 1998 Edition with 2000 Addenda, Code Section NB-3228.5
3. WCAP-9620, Revision 1 (Proprietary), Reactor Internals Heat Generation and Neutron Fluences, A.H. Fero, December 1983
4. RSICC Computer Code Collection CCC-650, DOORS 3.2, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System, April 1998
5. RSIC Data Library Collection DLC-185, BUGLE-96, Coupled 47 Neutron, 20 Gamma Ray Group Cross-Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications, March 1996
6. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.2.3-1
Lower Internal Critical Component Stresses Due to FIV –Thermal Shield (TS) PBNP Units 1 and 2 EPU Conditions

Component	Maximum Alternating Stress psi		ASME Code Endurance Limit[1] (high-cycle fatigue) psi
	Current AOR[2]	After EPU	
TS Top Support Bolts	[ ]a,c	[ ]a,c	23,700
TS Flexures	[ ]a,c	[ ]a,c	23,700

1. Basis is ASME Code Section NB-3222 and Figure I-9.2.2, Curve A and Table I-9.2.2.
2. Based on similar 2-loop plant, R.E. Ginna

Table 2.2.3-2
Upper Internal Critical Component Strains Due to FIV PBNP Units 1 and 2 EPU Conditions

Component	Maximum Mean Strain in./in. × 10^{-6} Current AOR[2]	Maximum Mean Strain in./in. × 10^{-6} After EPU	ACCEPTABLE[1] Mean Strain in./in. × 10^{-6}	Maximum Alternating Dynamic Strain in./in. × 10^{-6} Current AOR[2]	Maximum Alternating Dynamic Strain in./in. × 10^{-6} After EPU	ACCEPTABLE[1] Alternating Dynamic Strain in./in. × 10^{-6}
Guide Tubes with Core[3]	[ ]^{a,c}	[ ]^{a,c}	266.0	[ ]^{a,c}	[ ]^{a,c}	± 65.0
Guide Tubes without Core[3]	[ ]^{a,c}	[ ]^{a,c}	266.0	[ ]^{a,c}	[ ]^{a,c}	± 65.0

1. Basis of acceptance is from measured strain data
2. Based on similar 2-loop plant, R.E. Ginna
3. The description guide tube with core, means that the data used includes fuel in-place in the core region and guide tube without core, means that the data used is from original plant start-up hot functional testing, during which there was no fuel present in the core region.

Table 2.2.3-3
Reactor Internal Components Stresses and Fatigue Usage Factors
PBNP Units 1 and 2 EPU Conditions

	Stress Intensity (ksi) S.I. = ($P_m + P_b + Q$)		Allowable S.I. ($3 S_m$) ksi	Fatigue Usage Factor	
Component	**Current AOR**	**After EPU**		**Current AOR**	**After EPU**
Upper Support Plate	N/A	28.79	49.20	N/A	0.79
Deep Beam Structure	Small	Small	49.20	0.0	0.0
Upper Core Plate	28.80	45.70	48.60	0.0565	0.066
Upper Core Plate Alignment Pins	51.48[1]	38.507[1]	34.44[2]	0.30	0.583
Upper Support Columns	N/A	21.194	49.20	N/A	0.022
Upper Support Columns Fasteners and Welds	N/A	11.284	49.20	N/A	0.021
Lower Core Support Plate	36.825	36.624	49.20	0.067	0.024
Lower Core Plate	45.10	45.10	48.60	0.908	0.908
Lower Support Columns	40.833	20.21	49.20	0.144	0.023
Core Barrel Assembly:					
Upper Girth Weld	26.31	56.077[1]	49.20	0.21	0.029
Lower Girth Weld	31.95	53.878[1]	49.20	0.042	0.115
Outlet Nozzle	37.984[1]	32.076	34.44[2]	0.549	0.202
Core Barrel Flange	47.354	47.486	49.20	.023	0.021
Lower Radial Restraints–Key Base	N/A	40.482	49.20	N/A	0.076
Lower Radial Restraints–Key Weld	N/A	79.5001	34.442	N/A	0.140

Notes:
1. [ ]^{a,c}
2. Allowable based on weld quality factor

Table 2.2.3-4
Comparison of Original Zone Average Heating Rates with Current Analysis

Location	Region Average Long Term Heating Rates (Btu/hr-lbm)		
	WCAP-9620 Analysis	**Maximum From EPU Analysis**	**Ratio (EPU)/(Design)**
Baffle Plate 1	757	500	0.66
Baffle Plate 2	942	813	0.86
Baffle Plate 3	941	840	0.89
Baffle Plate 4	841	650	0.77
Baffle Plate 5	852	678	0.80
Core Barrel	260	246	0.94
Thermal Shield	45.2	43	0.95

Note: For each internals component, the heating rate value listed for the EPU analysis represents the maximum calculated value from the evaluation of the projected fuel management strategy.

Table 2.2.3-5
Spatial Distribution of Long-Term Heating Rates in the Upper Core Plate
Reactor Power = 2050 MWt

Radial Mesh Midpoint (inches)	Heat Generation Rate (BTU/hr-lbm)					
	Bottom Surface	Distance Through Plate (inches)				Top Surface
	0.00	0.19	0.56	0.94	1.31	1.50
0.59	500.0	470.6	397.0	338.2	290.7	280.0
1.77	490.0	459.9	389.7	333.4	287.9	277.9
2.95	488.4	457.1	386.3	330.4	285.5	275.7
4.13	488.0	457.1	385.2	329.1	284.2	274.5
5.31	486.9	456.0	384.5	328.3	283.4	273.7
6.50	486.0	455.2	383.6	327.6	282.8	273.1
7.68	484.9	454.2	382.9	326.9	282.3	272.5
8.86	484.2	453.5	382.1	326.3	281.7	272.0
10.04	483.4	452.7	381.5	325.7	281.1	271.4
11.22	482.8	452.1	380.9	325.1	280.6	270.9
12.40	481.9	451.3	380.2	324.5	280.0	270.3
13.58	481.0	450.4	379.4	323.8	279.3	269.6
14.76	479.8	449.3	378.4	322.9	278.5	268.8
15.94	478.4	448.0	377.3	321.9	277.6	267.9
17.13	476.7	446.4	375.9	320.8	276.6	266.8
18.31	474.7	444.5	374.3	319.3	275.3	265.6
19.49	472.2	442.2	372.3	317.6	273.7	264.1
20.67	469.3	439.5	370.0	315.6	271.9	262.3
21.85	466.0	436.3	367.3	313.2	269.8	260.2
23.03	462.0	432.5	364.1	310.4	267.4	257.8
24.21	457.3	428.1	360.3	307.2	264.5	255.0
25.39	451.8	422.9	355.8	303.3	261.1	251.7
26.57	445.5	416.9	350.8	298.9	257.3	247.9
27.76	438.1	410.0	344.9	293.9	252.8	243.6
28.94	429.6	402.0	338.1	288.0	247.7	238.7
30.12	419.8	392.8	330.3	281.3	241.9	233.0
31.30	408.7	382.3	321.4	273.8	235.3	226.7
32.48	396.2	370.6	311.5	265.2	228.0	219.6
33.66	382.1	357.4	300.3	255.8	219.8	211.7

Table 2.2.3-5
Spatial Distribution of Long-Term Heating Rates in the Upper Core Plate
Reactor Power = 2050 MWt

Radial Mesh Midpoint (inches)	Heat Generation Rate (BTU/hr-lbm)					
	Bottom Surface	Distance Through Plate (inches)				Top Surface
	0.00	0.19	0.56	0.94	1.31	1.50
34.84	366.3	342.6	288.1	245.2	210.9	203.0
36.02	349.4	326.9	274.7	234.1	201.2	193.7
37.20	331.5	310.0	260.9	222.1	190.8	183.7
38.39	313.1	293.1	246.0	209.1	179.7	173.0
39.57	292.9	273.5	229.3	195.3	167.8	161.7
40.75	269.4	251.7	212.2	180.8	155.6	149.9
42.52	237.3	222.6	187.7	160.1	137.7	132.7
44.09	212.9	199.1	167.5	142.7	122.6	118.1
44.88	199.6	186.6	155.9	132.6	113.9	109.6
45.67	184.9	173.1	145.1	122.9	105.3	101.3
46.46	169.6	159.1	133.5	113.0	96.5	92.8
47.05	158.3	148.4	124.1	105.0	89.5	86.0
47.44	149.0	139.6	116.6	98.5	84.0	80.7
47.83	137.8	129.1	108.1	91.4	78.0	75.0
48.23	125.6	117.6	98.6	83.7	71.7	69.1
48.71	95.5	89.3	76.1	65.1	56.4	55.9
49.27	67.9	64.3	56.4	48.8	43.3	44.1
49.96	58.9	54.2	44.0	37.6	33.5	34.6
50.79	57.6	52.0	38.4	31.0	27.3	28.2
51.61	55.5	50.2	36.0	27.6	23.4	24.2
52.44	50.9	46.1	32.9	24.9	20.6	21.1
53.26	45.1	40.8	28.8	21.7	18.0	18.4
54.09	38.5	34.6	24.2	18.2	15.2	15.6
54.50	32.9	30.0	21.8	16.5	13.7	13.8

Table 2.2.3-6
Spatial Distribution of Long-Term Heating Rates in the Lower Core Plate
Reactor Power = 2050 MWt

Radial Mesh Midpoint (inches)	Heat Generation Rate (BTU/hr-lbm)					
	Bottom Surface	Distance Through Plate (inches)				Top Surface
	0.00	0.19	0.56	0.94	1.31	1.50
0.59	944.3	977.0	1147.5	1372.6	1667.2	1756.9
1.77	944.1	975.6	1146.6	1371.0	1669.3	1759.0
2.95	944.8	976.2	1147.1	1372.2	1672.1	1761.0
4.13	945.6	977.2	1148.1	1373.3	1673.1	1762.0
5.31	946.4	978.0	1149.0	1374.0	1674.6	1763.5
6.50	947.1	978.8	1149.7	1374.9	1675.9	1764.7
7.68	947.5	979.3	1150.4	1375.9	1676.8	1765.5
8.86	948.0	979.8	1151.2	1376.6	1677.6	1766.3
10.04	948.6	980.5	1151.9	1377.5	1678.7	1767.3
11.22	949.2	981.2	1152.8	1378.6	1680.0	1768.6
12.40	949.9	982.0	1154.0	1380.0	1681.7	1770.3
13.58	950.9	983.2	1155.6	1382.1	1684.1	1772.8
14.76	952.0	984.4	1157.4	1384.4	1686.9	1775.7
15.94	952.8	985.4	1159.0	1386.5	1689.4	1778.4
17.13	953.2	986.0	1160.0	1387.9	1691.2	1780.2
18.31	952.8	985.7	1160.1	1388.2	1691.5	1780.6
19.49	951.4	984.4	1158.9	1386.9	1690.0	1779.1
20.67	948.5	981.5	1155.7	1383.3	1685.6	1774.4
21.85	944.2	977.1	1150.6	1377.0	1677.9	1766.3
23.03	938.7	971.4	1143.9	1368.9	1667.9	1755.7
24.21	932.4	964.8	1136.2	1359.6	1656.4	1743.5
25.39	925.6	957.9	1128.1	1349.8	1644.4	1730.7
26.57	918.7	950.8	1120.1	1340.2	1632.4	1718.0
27.76	911.6	943.8	1112.3	1331.0	1620.8	1705.6
28.94	904.4	936.8	1104.9	1322.6	1610.3	1694.5
30.12	896.3	929.0	1096.6	1313.5	1599.0	1682.6
31.30	886.2	919.1	1086.7	1302.0	1584.6	1667.4
32.48	872.7	905.8	1072.4	1285.7	1564.4	1646.2
33.66	854.3	887.4	1052.0	1262.1	1535.3	1615.7

Table 2.2.3-6
Spatial Distribution of Long-Term Heating Rates in the Lower Core Plate
Reactor Power = 2050 MWt

Radial Mesh Midpoint (inches)	Heat Generation Rate (BTU/hr-lbm)					
	Bottom Surface	Distance Through Plate (inches)				Top Surface
	0.00	0.19	0.56	0.94	1.31	1.50
34.84	829.4	862.0	1023.5	1228.8	1494.3	1572.8
36.02	797.0	828.9	984.6	1183.1	1438.7	1514.5
37.20	755.9	786.3	934.6	1122.8	1365.2	1437.4
38.39	706.2	734.5	872.8	1048.5	1274.1	1341.7
39.57	648.7	674.1	800.4	961.6	1168.5	1230.5
40.75	584.4	606.7	719.6	863.8	1049.6	1105.5
42.52	488.8	506.5	598.0	716.6	870.5	916.9
44.09	407.9	422.0	496.4	593.9	721.3	758.5
44.88	361.5	373.5	437.9	523.6	634.5	667.6
45.67	317.4	327.3	382.9	456.7	552.7	582.0
46.46	276.2	284.1	331.4	394.9	476.6	501.9
47.05	247.8	254.5	296.5	352.8	424.2	446.8
47.44	228.2	233.8	271.8	322.2	386.5	408.2
47.83	208.6	213.1	246.9	292.2	350.6	371.1
48.23	189.1	191.9	222.0	263.6	316.7	335.8
48.71	162.6	161.4	186.1	222.8	275.1	294.9
49.27	137.7	133.9	152.9	185.4	235.6	255.4
49.96	114.6	109.8	124.7	152.9	198.4	216.2
50.79	94.9	90.0	101.5	125.6	164.6	180.8
51.61	79.2	74.5	83.5	103.5	136.8	151.7
52.44	66.0	61.5	68.3	84.7	114.0	127.7
53.26	54.3	50.2	54.7	68.4	94.4	106.8
54.09	43.5	39.7	42.7	53.8	76.3	87.5
54.50	36.8	34.7	37.7	47.3	65.7	74.6

2.2.4 Safety-Related Valves and Pumps

2.2.4.1 Regulatory Evaluation

PBNP has reviewed safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Boiler & Pressure Vessel Code, within the scope of Section XI of the Code, and the ASME Operations and Maintenance Code, as applicable. The 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 PBNP's motor operated valve program related to Generic Letter (GL) 89-10, Consideration of the Results of NRC-Sponsored Tests of Motor-Operated Valves, GL 96-05, Periodic Verification Of Design-Basis Capability of Safety-Related Motor-Operated Valves, and GL 95-07,Pressure Locking And Thermal Binding of Safety-Related Power-Operated Gate Valves. Lessons learned from the motor-operated valve program and the applications of those lessons learned to other safety-related power-operated valves were also evaluated.

The NRC's acceptance criteria are based on:

- General Design Criterion (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.
- GDC 37, 40, 43, and 46, insofar as they require that the emergency core cooling system, 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.
- 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.
- 10 CFR 50.55a(f) insofar as it requires that pumps and valves subject to that section must meet the in-service testing program requirements identified in that section.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 3.9.3 and 3.9.6, and other guidance provided in Matrix 2 of RS-001

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR) Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50 Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion
(PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A, GDC 1, 37, 40, 43, 46 and 54 are as follows

CRITERION: Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

FSAR Section 1.3.1, Overall Plant Requirements describes the quality requirements applied to safety-related systems and components. Safety-related systems and components were designed, fabricated, inspected, and erected to the applicable provisions of the then-recognized codes, good nuclear practice, and the quality standards that reflected their importance.

CRITERION: All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public. (PBNP GDC 38)

A comprehensive program of plant testing is formulated for all equipment systems and system control vital to the functioning of engineered safety features. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system and periodic tests of the actuation circuitry and mechanical components to assure reliable performance, upon demand, throughout plant life.

The initial tests of individual components and the integrated test of the system as a whole complement each other to assure design of the system and to prove proper operation of the actuation circuitry.

The engineered safety features components are designed to provide for routine periodic testing.

CRITERION: Design provisions shall be made so that components of the emergency core cooling system can be tested periodically for operability and functional performance. (PBNP GDC 46)

The design provides for periodic testing of active components of the safety injection system for operability and functional performance. The safety injection pumps can be tested periodically during plant operation using the full flow recirculation test lines provided. The residual heat removal pumps are used every time the residual heat removal system is put into operation. Remotely operated valves can be exercised and are tested in accordance with the Inservice Testing Program filed OM Code.

CRITERION: Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits. (PBNP GDC 57)

Capability is provided to the extent practical for testing the functional operability of valves and associated apparatus during periods of reactor shutdown. Local leak re-testing of containment isolation valves are performed as required during periods of reactor shutdown.

Valves in the emergency core cooling systems (safety injection and residual heat removal) are not considered to be isolation valves in the usual sense in as much as the system would be in operation under accident conditions. The pressure boundary integrity of these closed systems outside containment is monitored by the leakage reduction and preventive maintenance program.

CRITERION: The containment pressure reducing systems shall be designed, to the extent practical, so that active components, such as pumps and valves, can be tested periodically for operability and required function performance. (PBNP GDC 59)

All active components in the containment spray systems are adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after any component maintenance.

The component cooling water pumps and the service water pumps which supply the cooling water to the residual heat exchangers are in operation on a relatively continuous schedule during plant operation. Idle pumps may be tested by changing the operating pump(s).

The containment air recirculation cooling system is designed to the extent practical so that the components can be tested periodically and, after any component maintenance, for operability and functional performance.

CRITERION: Design provisions shall be made to the extent practical so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance. (PBNP GDC 63)

All active components of the containment spray system are adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after component maintenance.

In addition to the evaluations described in the FSAR, systems and components have been evaluated for plant license renewal. Plant system and component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the PBNP, Units 1 and 2, (NUREG-1839), dated December 2005

The safety-related valves and pumps are addressed within the SER under the systems that contain them. In-service testing of safety-related valves and pumps was evaluated as part of the Periodic Surveillance and Preventive Maintenance Program.

Performance/Inservice Testing of Safety-Related Pumps and Valves

The PBNP Inservice Testing (IST) Program is discussed in FSAR Chapter 6, Engineered Safety Features, Chapter 9, Auxiliary and Emergency Systems and Chapter 11, Waste Disposal System. The PBNP Inservice Testing Program Document details the technical basis and provides the overall description of the activities planned to fulfill the IST requirements for pumps and valves as specified in 10 CFR 50.55a(f)(4)(ii), and required by PBNP Technical Specification 5.5.7.

As described in the PBNP Inservice Testing Program Document, the 4th 10-year Interval Pump and Valve IST Program was developed in accordance with the rules and requirements specified in the ASME OM Code, 1995 Edition with the 1996 Addenda (OMa Code 1996) as referenced by 10 CFR 50.55a(b)(2). In addition to the ASME Code, this IST Program was prepared using the guidelines provided in non-mandatory Appendix A of the OM Code, Preparation of Test Plans, NRC NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants, Generic Letter (GL) 89-04, Guidance on Developing Acceptable Inservice Testing Programs, and NUREG/CR-6396, Examples, Clarification, and Guidance on Preparing Requests for Relief from Pump and Valve Inservice Testing Requirements. These documents provide the basis for component selection, test requirements, relief requests, and format.

USAS B31.1 was the construction code for PBNP. Since PBNP was not constructed to Section III of the ASME Boiler and Pressure Vessel Code, components were originally neither designed to ASME Code Class 1, 2, and 3 requirements nor classified as such. The ASME Code classifications of systems and components at PBNP were established only to define components subject to inservice inspection and testing requirements. The PBNP Inservice Testing Program Document describes the selection methodology used to classify components in more detail.

PBNP TS 5.5.7, Inservice Testing Program, states that the Inservice Testing Program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components and that the program shall include testing frequencies specified in the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) and applicable Addenda.

Motor-Operated Valve Program

Generic Letters 89-10 and 96-05

PBNP's Motor-Operated Valves (MOV) program was established in response to IE Bulletin 85-03. The program was later expanded to address the recommendations of GL 89-10 (Reference 2) and GL 96-05 (Reference 1). The scope of the MOV program is described in Component Maintenance Procedure (CMP) 2.2, Motor Operated Valves, and encompasses three attributes:

- MOV that have active safety functions (as defined in the IST Background Document)
- MOV that are considered passive but are moved out of the safety related position without declaring the affected safety system inoperable
- MOV that are found to have a risk significance of medium or high as defined in GL 96-05 JOG guidance documents

The motor-operated valve program is described in the PBNP Motor-Operated Valve Program. The motor-operated valve program is used to establish torque switch and limit switch settings for safety-related AC and DC motor-operated valves, and to demonstrate valve operability during normal and abnormal design-basis events. The program also includes periodic and post-maintenance and repair testing to verify continued valve operability. This program includes periodic verification of motor-operated valve capability and trending of motor-operated valve problems. The motor-operated valve program and station procedures are designed to ensure that the switch settings of the motor-operated valves in the program are selected, set, and maintained correctly to accommodate the maximum differential pressures expected across the valves during both normal and abnormal design-basis events throughout the life of the plant.

The NRC closed out its review of PBNP's GL 89-10 Program in a letter dated July 13, 1995 (Reference: Letter from E.M. Kelly, NRC, to R. Link, WEPCO, Close-Out Inspection of GL 89-10 (NRC Inspection 50-266/95007 (DRS) and Inspection 50-301/95007 (DRS), July 13, 1995). In response to GL 96-05, the program was enhanced to include provisions for continually monitoring valve performance for degradation and periodic verification of program effectiveness. In a Safety Evaluation dated June 22, 2000 (Reference: Letter from Beth A. Wetzel, NRC, to Michael B. Sellman, WEPCO, Point Beach Nuclear Plant, Units 1 and 2 – Closeout of Licensing Action for GL 96-05, Periodic Verification of Design-Basis Capability of Safety Related Motor-Operated Valves (TAC NOS. M97087 AND M97088), the NRC stated that PBNP has established an acceptable program to verify periodically the design-basis capability of the safety-related MOVs at PBNP, including the licensee's participation in the JOG Program on MOV Periodic Verification and the additional actions described in its submittals, and is adequately addressing the actions required in GL 96-05.

Generic Letter 95-07

In response to GL 95-07 (Reference 3), PBNP considered the safety-related motor-operated gate valves, including all valves within the GL 89-10 Program that could be potentially susceptible to the phenomenon of pressure locking and thermal binding, and performed assessments, analyses, or identified previous valve modifications to justify continued operability of the valves. The assessments of each valve were based upon the operational configurations and conditions imposed.

- As addressed in FSAR Section 9.2, Residual Heat Removal, a 3/8-inch hole has been drilled in the RCS-side disc of each of the RHR loop isolation motor-operated valves (RH-700 and RH-701) and a 3/8-inch hole has also been drilled in the RCS-side disc of the RHR return isolation valve (RH-720) in order to minimize the effects of pressure locking.
- The Power Operated Relief Valves (PORV) block valves, (RC-5 15 and RC-5 16 on each unit), were identified as being susceptible to thermal binding and pressure locking. All four valves have been replaced with valves which are not susceptible to thermal binding
- The Containment Spray Pump Discharge Redundant Isolation Valves SI-860 A-D (four safety-related valves per unit) were noted to be susceptible to pressure locking during the performance of inservice tests. The long-term, permanent corrective action for these eight valves was to revise the inservice test procedures to include cycling of the associated valve after each containment spray pump is secured. This eliminated any valve bonnet pressure buildup caused during inservice testing.
- For applicable valves, an analysis was performed to show that the MOV actuator has sufficient thrust to overcome the pressure-locked bonnet condition

- For all other valves determined to be susceptible to pressure locking/thermal binding, the valves were justified based on valve design or upon the operational configuration and conditions imposed

In a Safety Evaluation dated January 8, 1998 (Reference: Letter from Linda L. Gundrum, NRC, to Richard R. Grigg, WEPCO, Point Beach Nuclear Plant, Unit Nos. 1 and 2 – Issuance of Safety Evaluation Re: GL 95-07 Pressure Locking and Thermal Binding of Safety-Related Power Operated Relief Valves (TAC NOS. M93505 AND M93506), the NRC stated that PBNP had adequately addressed the actions requested in GL 95-07.

2.2.4.2 Technical Evaluation

Introduction

PBNP valves and pumps important to safety are exercised and tested in accordance with the PBNP Inservice Testing Program filed with the NRC and based on the ASME OM Code. The program is specifically referenced for testing requirements in the FSAR on a system by system basis. Paragraph (f) of 10 CFR 50.55a requires that IST Programs be updated at ten year intervals to comply with the latest NRC approved edition and addenda of the ASME Code incorporated by reference in 10 CFR 50.55a, Paragraph (b), 12 months prior to the start of the interval. The 4th 10-year test interval for PBNP commenced September 1, 2002 for Unit 1 and October 1, 2002 for Unit 2. The 4th 10-year interval pump and valve IST Program was developed in accordance with the rules and requirements specified in the ASME OM Code, 1995 Edition with the 1996 Addenda (OMa Code 1996) as referenced by 10 CFR 50.55a(b)(2).

PBNP defines pumps and valves included in the IST Program as those in systems or portions of systems which are required to accomplish the following functions:

- Shutdown the reactor to Hot Shutdown/maintain Hot Shutdown condition (reactivity control, core heat removal, steam generator heat removal, pressure inventory and control, reactor coolant system pressure and inventory control)
- Mitigate the consequences of an accident (reactivity control, core heat removal, reactor coolant system integrity, containment integrity)
- Provide overpressure protection or vacuum relief for systems or portions of systems required to perform the above-described functions

The valves and pump testing frequency is in accordance with the Inservice Testing Program. Operating experience has shown that these components normally pass the surveillance when performed at the frequency required by the Inservice Testing Program. Therefore, the frequency is acceptable from a reliability standpoint.

Motor-Operated Valve Program

The PBNP Motor-Operated Valve Program implements the actions required to comply with the recommendations of GL 89-10 for safety-related motor-operated valves which meet the GL 89-10 selection criteria. In accordance with the IST program, PBNP screens motor-operated valves to identify which valves should be included within the scope of the Motor-Operated Valve

Program and which documents the "design basis" operating conditions under which these valves must perform their safety-related functions.

PBNP has established the MOV Program in response to GL 89-10 and subsequently GL 96-05. The Program utilizes periodic diagnostic testing, and preventative maintenance to ensure the continued operability of safety related and augmented quality motor-operated valves. The frequency of diagnostic testing and preventative maintenance is dependent on valve classification, service conditions and monitored test parameter margins. The PBNP MOV Program is subject to internal and external agency audit and inspection, and satisfies 10 CFR 50.55a(b)(3)(ii) requirements for ensuring the continued operability of motor-operated valves.

Description of Analyses and Evaluations

Performance/Inservice Testing of Safety-Related Pumps and Valves

The PBNP Inservice Testing Program includes pumps and valves required to perform the safety functions for the following systems:

System	Components in IST Program		System Conditions Changed by EPU
	Pumps	Valves	
Auxiliary Feedwater	X	X	X
Chemical and Volume Control		X	
Component Cooling Water	X	X	X
Condensate and Feedwater		X	X
Containment Isolation		X	X
Containment Spray	X	X	
Diesel Fuel Oil	X	X	
Diesel Starting Air		X	
Fire Protection		X	
Instrument Air		X	
Main Steam		X	X
Post-Accident Cont. Vent & Drain		X	
Reactor Coolant		X	
Residual Heat Removal	X	X	
Safety Injection	X	X	
Sampling		X	
Service Water	X	X	X
Spent Fuel Pool Cooling	X	X	
Waste Disposal		X	

The impact of EPU on components in the IST program and the associated testing requirements and acceptance criteria were reviewed and are not affected for most components within the program:

- The normal, transient and accident EPU operating conditions are essentially unchanged for the Chemical and Volume Control System (LR Section 2.1.11), Sampling valves connected to the RCS, and Residual Heat Removal System (LR Section 2.8.4.4). These IST requirements are not affected by EPU.
- The normal, transient and accident EPU operating conditions are unchanged for the Diesel Fuel Oil, Diesel Starting Air, Fire Protection, Instrument Air, and Waste Disposal systems. These components and their IST requirements are not affected by EPU.
- The normal, transient and accident EPU operating conditions are essentially unchanged for the Safety Injection system and the Containment Spray System (addressed as part of Containment Heat Removal, LR Section 2.6.5). However, as discussed in LAR 241 (ML083450683), valves in these systems are being modified to provide system throttling during ECCS recirculation mode. These modifications have no effect on the parameters affecting other safety related valves and pumps, and are therefore acceptable for EPU condition.
- The Reactor Coolant System operating pressure will not change for EPU as discussed in LR Section 2.2.2.6, Reactor Coolant Pumps and Supports; all valve evaluations are based on conservative system pressures which are still bounding for EPU.The pressurizer safety valves set point allowables are being changed. The IST program will be updated.
- The Spent Fuel Cooling system (LR Section 2.5.4.1) experiences higher heat loads at EPU conditions, but will be operated in the same temperature range as before EPU by controlling the decay time prior to refueling. There is no flow or other change to the system. These components and their IST requirements are not affected by EPU
- The normal, transient and accident EPU operating conditions for the Component Cooling Water system (LR Section 2.5.4.3, Reactor Auxiliary Cooling Water System), Service Water system (LR Section 2.5.4.2, Station Service Water Systems), and Post-Accident Cont. Vent & Drain (addressed in LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup) experience somewhat higher heat loads at EPU conditions and portions of the systems will operate at slightly higher temperatures than prior to EPU. However, there are no changes to the system operating pressures and system flow rates at EPU. Since the unchanged parameter form the basis for the IST program requirements (e.g., motor-operated valve thrust/torque values) these components and their IST requirements are not affected by EPU
- The design requirements for Containment Isolation valves are not affected by EPU, except as discussed for Main Steam, Auxiliary Feedwater and Condensate and Feedwater systems. However, the pending AST LAR 241 (ML083450683) reduces the overall acceptable containment leakage rate which may require changes to the individual valve leakage rate testing acceptance criteria. The tests which measure containment isolation valve leakage rates (Type C tests) are performed at the containment design pressure, which bounds the peak calculated containment internal pressure for the design basis loss-of-coolant accident, P_a. In accordance with the PBNP Technical Specifications Bases B 3.6.1, the value of P_a is

60 psig which is unchanged by EPU. Accordingly, no change is required in the containment leakage test pressure at EPU conditions

The systems that have changes significant to the IST program are discussed in more detail in following sections.

Main Steam System

The Main Steam system (LR Section 2.5.5.1, Main Steam) is operated at significantly higher mass flow rates at EPU conditions and slightly different temperature and pressure conditions, resulting in significantly increased system flow velocities. Safety-related valves in the main steam system include the main steam isolation valves, main steam check valves (non-return valves NRVs), main steam safety valves, main steam atmospheric relief valves, the turbine driven auxiliary feedwater pump steam isolation valves, and the check valves in the steam inlet lines to the turbine driven auxiliary feedwater pump.

- The EPU does not affect the main steam isolation valves closing time. The flow under EPU conditions will enhance the closing of these valves, thus ensuring that the Inservice Testing Program/Technical Specification required closing time is met. However, these valves are being modified for EPU conditions. Details are included in LR Section 2.5.5.1, Main Steam.
- The main steam check valves are free swinging gravity closing type check valves, which protect the main steam header against reverse flow from one steam generator to another in event of a steam line rupture. EPU does not affect the Technical Specification 3.7.2.1 closure time requirement for these valves. Because these valves protect the main steam header against reverse flow, the ability of the valves to close is not affected by the increased steam flow at EPU conditions. The EPU does not create a new condition which is not currently part of the existing testing criteria. Accordingly, the EPU does not affect the Inservice Testing Program performance criteria associated with these valves.
- The setpoints for the third and fourth banks of Main Steam Safety Valves (MSSVs) are changed from 1125 psig to 1105 psig for EPU. This change has no impact on the ability of the valves to perform their safety function but improves the plant response to certain transients. In addition, evaluation shows that the existing main steam safety valve capacities are acceptable for operation under EPU conditions as discussed in LR Section 2.5.5.1, Main Steam. Accordingly, a revision of the Inservice Testing Program/Technical Specification setpoint requirements for these valves is necessary.
- The set pressure of the atmospheric relief valves is based on plant no-load conditions and the lowest set pressure of the main steam safety valves. Since neither the no-load steam pressure nor the lowest main steam safety valve setpoint pressure is changing for the EPU, there is no need to change the atmospheric relief valve setpoint. The existing capacity of the main steam atmospheric relief valves is adequate to support operation under EPU conditions as discussed in LR Section 2.5.5.1, Main Steam. The Inservice Testing Program/Technical Specification test/operability requirements for these valves, which include periodic cycling of the valves, are not affected by the EPU.
- The check valves in the steam inlet lines to the turbine driven auxiliary feedwater pump function to isolate one steam generator from the other in the event of a main steam line

break. This performance requirement is not changed by the EPU. The EPU does not create a condition whereby the valves must operate against different forces than are currently applied.

Auxiliary Feedwater System

The Auxiliary Feedwater (AFW) system is being reconfigured for EPU operation as discussed in LR Section 2.5.4.5, Auxiliary Feedwater. The AFW pump flow rate requirements increase at EPU conditions and new motor driven (MD) AFW pumps are being installed. Additionally, the system is being "unitized" and new piping and several new valves (e.g., valves to allow auto switch over of the pump suction, flow control valves and check valves on each SG feed line) are being added. The IST requirements for these changes, including changing the MD AFW pump degradation curve will be evaluated and finalized as part of the plant modification process.

Condensate and Feedwater System

The Condensate and Feedwater system will operate at significantly increased flow rates and somewhat changed temperatures and pressures at EPU. The condensate and feedwater pumps are being replaced and new fast-closing isolation valves are being added on each feedwater line outside containment to isolate the steam generators (SGs) and minimize mass input to the SGs during main steam line breaks. Valves that perform a safety related function in the Condensate and Feedwater system include the feedwater isolation valves, feedwater regulating valves (FRV), FRV bypass valves, as discussed in LR Section 2.5.5.4, Condensate and Feedwater System. Any required changes to Inservice Testing Program requirements for the modified valves addressed below will be developed as part of the plant modification process.

- New fast closing (5 second) air operated Main Feedwater isolation valves (1/2CS 03124 & 03125) will be added to the system to limit the feedwater flow to the containment during a main steam line break event. These valves are classified as safety related and will be evaluated for addition to the IST program as part of the plant modification process, thereby assuring compliance with PBNP GDC 1, which states that Quality assurance programs, test procedures, and inspection acceptance criteria is required. New safety related air supply valves will also be added in conjunction with this modification.
- The Main Feedwater regulating valves (MFRV) will experience a higher operating flow at EPU conditions. Valves (1/2CS-00466 and 00476) have been evaluated and are being modified with higher CV trim and actuators for operation under EPU conditions. Valve closing time is changed from 5 seconds to 10 seconds.
- The MFRV bypass valves will experience the same differential design pressure at EPU conditions. They were evaluated and found acceptable at EPU conditions. The bypass valves are discussed in LR Section 2.5.5.4, Condensate and Feedwater.
- The feedwater check valves function as feedwater line containment isolation valves, and also function to prevent leakage of water from the auxiliary feedwater system into the main feedwater system. Physical changes to condensate and feedwater valves and piping that resulted from EPU conditions were incorporated into the system evaluation and verified as acceptable as discussed in LR Section 2.5.5.4, Condensate and Feedwater. Accordingly, the EPU does not affect the isolation functionality of these valves.

Motor-Operated Valve Program

- Generic Letter 89-10

  The EPU effect on maximum differential pressures/line pressures determined in the design analysis of GL 89-10 motor-operated valves in all systems have been evaluated and found acceptable based on calculations which determine motor-operated valve thrust and torque values. The MOV program includes valves in the following systems:

  - Auxiliary Feedwater System (AF)
  - Component Cooling System (CC)
  - Condensate System (CS)
  - Chemical and Volume Control System (CV)
  - Circulating Water System (CW)
  - Fuel Oil System (FO)
  - Fire Protection System (FP)
  - Gas Turbine System (GT)
  - Main Steam System (MS)
  - Cross Over Steam Dump System (OS)
  - Service Water System (SW)
  - Residual Heat Removal System (RH)
  - Safety Injection System (SI)
  - Reactor Coolant System (RC)

  The evaluation methodology includes the following criteria:

  - Determine if the system pressure and valve differential pressure is unchanged or decreased by EPU which precludes the need for further evaluation.
  - Determine if the valve has the potential for a larger pressure differential under EPU conditions.
  - Determine if the valve/system is undergoing restructuring and reconfiguration prior to EPU implementation, such as Containment Spray and Safety Injection as discussed in the pending AST LAR 241 (ML083450683) or Auxiliary Feedwater System (LR Section 2.5.4.5, Auxiliary Feedwater System). These valves were eliminated from further evaluation since the plant modification process will ensure the necessary qualification is achieved.

  MOVs in the GL 89-10 program in each system were evaluated by reviewing the impact of EPU on the functional qualification of the valves. The Reactor Coolant System operating pressure will not be changed for EPU, as addressed in Section 2.2.2.6, Reactor Coolant Pumps and Supports. Of the three MOVs included in the system, one is non safety related relative to operation and the other two are normally open and by design, start to close only at or below a preset pressure (lower than system operating pressure). This pre-set pressure is not changed by EPU. The results of EPU evaluations, show that EPU conditions have no effect on the maximum differential pressures / line pressures determined in the design analysis of GL 89-10 motor-operated valves in these systems, and therefore do not affect the calculations which determine motor-operated valve thrust and torque values. In addition the minimum voltage re quirements are met at the EPU conditions.

- Generic Letter 96-05

  Other than valves added as part of the Auxiliary Feedwater System reconfiguration, no motor-operated valves are required to be added to the Motor-Operated Valve Program as a result of the EPU. The EPU related changes in electrical demand are acceptable as discussed in LR Section 2.3.3, AC Onsite Power System. The EPU has negligible effect on the differential pressures/line pressures determined in GL 89-10 motor-operated valve design analyses. The risk significance of GL 89-10 MOVs is not affected by the EPU. Therefore, the EPU does not affect the requirements of the program for periodic verification of safety-related motor-operated valve capabilities in accordance with GL 96-05.

- Generic Letter 95-07

  Prior to EPU, all motor operated gate valves that were susceptible to pressure locking and/or thermal binding were previously either fixed by modifications or justified by evaluation. This included modifications by drilling a hole in the upstream disk and by venting the bonnet or by changing the type of valve that renders it not susceptible to pressure locking or thermal binding. Some valves were changed from gate valves to angle globe, plug, solid wedge gate, globe or other types that are not susceptible to the phenomenon. The remaining valves originally justified as acceptable due to operating conditions such as low temperature and pressure. The original disposition for each valve was assessed for EPU acceptability by reviewing the associated pressure, temperature and system condition changes caused by EPU. The existing disposition was determined to remain applicable for EPU conditions for all valves. Therefore, for valves susceptible to pressure locking and/or thermal binding and justified on the basis of valve design, or on operational configuration/conditions imposed, the EPU does not affect valve design or function, or the operational considerations/conditions imposed.

  The EPU does not create any new conditions which would require motor operator modifications or result in valves becoming susceptible to pressure locking or thermal binding phenomena.

Lessons Learned

Regulatory requirements, other utility experience, EPRI guidelines, User Group recommendations, and vendor information are reviewed and factored into the preventive maintenance/test frequencies to the extent practical. In particular, preventive maintenance procedures are enhanced as appropriate to include User Group and EPRI recommendations and updates/notices from vendors.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Systems and components have been evaluated for plant license renewal. Plant system and component materials of construction, operating history, and programs used to manage aging effects are documented in Safety Evaluation Report Related to the License Renewal of the PBNP, Units 1 and 2, (NUREG-1839), dated December 2005.

The safety-related valves and pumps are addressed within the SER under the systems that contain them. Inservice testing of safety-related valves and pumps was evaluated as part of the Periodic Surveillance and Preventive Maintenance Program. Aging effects of safety-related valves and pumps are primarily managed by the Periodic Surveillance and Preventive Maintenance Program. Because no new materials are being added within existing evaluation boundaries, outside the modification process, and because component internal and external environments remain within parameters previously evaluated, implementation of the EPU does not diminish the ability of this program to provide reasonable assurance that the aging effects of safety-related valves and pumps will be effectively managed and that their functional performance will be maintained through the period of extended operation.

Results

The proposed EPU has no or minimal effect on most of systems that affect operational requirements of safety related pumps and valves. For the system impacted by EPU, justification for acceptance of the new condition was found and documented in this report. For all other systems with requirements falling under GL 89-10, GL 95-07 and GL 96-05, valves have been reviewed and found acceptable. The IST Program requirements for the safety related pumps and valves require some changes as identified in this section or will be confirmed as part of the plant modification process.

2.2.4.3 Conclusion

PBNP has assessed the effects of EPU related to the functional performance of safety-related valves and pumps and concludes that the safety-related pumps and valves are adequate to operate at EPU. PBNP further concludes that the effects of the proposed EPU on motor-operated valve programs related to GL 89-10, GL 96-05, and GL 95-07 have been adequately evaluated, and that the lessons learned from those programs to other safety-related power-operated valves has been addressed. Based on this, PBNP concludes that it has been demonstrated that safety-related valves and pumps will continue to meet PBNP GDCs 1, 38, 46, 57, 59 and 63 and the current PBNP licensing basis requirements following implementation of the proposed EPU. The proposed EPU is acceptable with respect to safety-related valves and pumps.

2.2.4.4 References

1. NRC Generic Letter 96-05, Periodic Verification of Design Basis Capability of Safety Related Power Operated Valves, dated September 18, 1996

2. NRC Generic Letter 89-10, Safety Related Motor Operated Valve Testing and Surveillance, dated June 28, 1989

3. NRC Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety Related Power Operated Gate Valves, dated August 17, 1995

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

2.2.5.1 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 release of radioactive materials to the environment is also covered by this section. The PBNP 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 safe shutdown earthquake (SSE) are not affected by an EPU.

The NRC's acceptance criteria are based on:

- GDC 1, insofar as it requires that Structures, Systems, and Components (SSC's) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed;
- GDC 30, insofar as it requires that components that are part of the Reactor Coolant Pressure Boundary (RCPB) be designed, fabricated, erected, and tested to the highest quality standards practical;
- GDC 2, insofar as it requires that SSC's important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions;
- 10 CFR 100, Appendix A, which sets forth the principal seismic and geological considerations of the seismic and geologic characteristics of the plant site;
- GDC 4, insofar as it requires that SSC's 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;
- 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;
- 10 CFR 50, Appendix B, which sets quality assurance requirements for equipment important to safety

Specific review criteria are contained in SRP Section 3.10.

PBNP Current Licensing Basis

Compliance with 10 CFR 50, Appendix B, Quality Assurance Criteria is described in FSAR Section 1.4, Introduction and Summary, Quality Assurance Program.

Site location, description, and information on the geology and seismology of the site that pertain to 10 CFR 100, Appendix A Seismic and Geologic Siting Criteria are described in FSAR Chapter 2 Sections 2.0, Site and Environment, 2.1, Site and Environment Site Location and Boundaries, 2.2, Site and Environment, Topography, 2.8, Site and Environment, Geology, and 2.9, Site and Environment Seismology.

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the seismic and dynamic qualification of mechanical and electrical equipment are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System and the Containment System structure are of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice. Particular emphasis is placed on the assurance of quality of the reactor vessel to obtain material whose properties are uniformly within code specifications. The concrete structure of the reactor containment conforms to the applicable portions of ACI-318-63 (Reference 2).

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

All piping, components, and supporting structures of the Reactor Coolant System are designed as Seismic Class I equipment. The Reactor Coolant System is located in the containment building whose design, in addition to being a Seismic Class I structure, also considers accidents or other applicable natural phenomena.

All electrical systems and components vital to plant safety, including the emergency diesel generators, are designed as Seismic Class I and designed so that their integrity is not impaired by the maximum potential earthquake, wind storms, floods or disturbances on the external electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a nuclear system accident or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event that their use is required.

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

This plant-specific General Design Criterion is very similar to 10 CFR 50 Appendix A GDC 4. Under the provisions of that criterion, the dynamic effects associated with postulated pipe ruptures of the RCS may be excluded from the design basis when appropriate analyses approved by the NRC demonstrate that the probability of such ruptures is extremely low. Analyses have been completed for the reactor coolant loop piping, the pressurizer surge line, the accumulator injection line piping including a portion of the RHR return line piping, the RHR return line and the RHR suction line. The NRC has approved the analyses. As such, the original design features of the facility to accommodate the dynamic effects of a pipe rupture associated with these lines are no longer applicable.

A loss-of-coolant accident or other plant equipment failure might result in dynamic effects or missiles. The steam generators are supported, guided, and restrained in a manner which prevents rupture of the steam side of a generator, the steam pipelines, and the feedwater piping as a result of forces created by a reactor coolant system pipe rupture. These supports, guides, and restraints also prevent rupture of the primary side of a steam generator as a result of forces created by a steam or feedwater pipeline rupture. The mechanical consequences of a pipe rupture are restricted by design such that the functional capability of the engineered safety features is not impaired.

For engineered safety features which are required to ensure safety in the event of such an accident or equipment failure, protection is provided primarily by the provisions which are taken in the design to prevent the generation of missiles. In addition, protection is also provided by the layout of plant equipment or by missile barriers in certain cases.

Injection paths leading to unbroken reactor coolant loops are protected against damage as a result of the maximum reactor coolant pipe rupture by layout and structural design considerations. Injection lines penetrate the main missile barrier, which is the loop compartment wall, and the injection headers are located in the missile protected area between the loop compartment wall and the containment wall. Individual injection lines, connected to the injection header, pass through the barrier and then connect to the loops. Separation of the individual injection lines is provided to the maximum extent practicable. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the loop compartment is possible.

The containment structure is capable of withstanding the effects of missiles originating outside the containment and which might be directed toward it so that no loss-of-coolant accident can result.

All hangers, stops and anchors are designed in accordance with USAS B31.1, Code for Pressure Piping, ACI 318, Building Code Requirements for Reinforced Concrete and AISC Specifications for the Design and Erection of Structural Steel for Buildings, which provide minimum requirements on material, design and fabrication with ample safety margin for both dead and dynamic loads over the life of the plant.

CRITERION: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes. (PBNP GDC 34)

The reactor coolant pressure boundary is designed to reduce to an acceptable level the probability of a rapidly propagating type failure. All pressure containing components of the reactor coolant system are designed, fabricated, inspected, and tested in conformance with the applicable codes at the time of order placement.

Generic Letter 87-02, Supplement 1, dated May 22, 1992, transmitted Supplemental Safety Evaluation Report No. 2 (SSER No. 2) on the Seismic Qualification Utility Group (SQUG) Generic Implementation Procedure, Revision 2, dated February 14, 1992 (GIP-2). SSER No. 2 approved the methodology in the SQUG generic implementation procedure for use in verification of equipment seismic adequacy; including equipment involved in future modifications and replacement equipment. In a letter dated July 7, 1998, the NRC accepted PBNP's response to Generic Letter 87-02, Supplement 1.

Additional information on the seismic and dynamic qualification of mechanical and electrical equipment is provided in FSAR Sections 4.1, Reactor Coolant System, Design Basis, 4.2, Reactor Coolant System, RCS System Design and Operation, 4.3, Reactor Coolant System, System Design Evaluation, 4.4, Reactor Coolant System, Tests and Inspections, 5.1, Containment System Structure, 5.6, Containment System Structure, Construction, 6.1, Engineered Safety Features, 7.2.3.4, Seismic Qualification of Protection System Equipment, 8.0, Introduction to the Electrical Distribution System and 9.0, Auxiliary and Emergency Systems. FSAR Appendix A.5, Seismic Design Analysis provides details with respect to the seismic qualification of piping and piping components.

In addition to the evaluations described in the FSAR, PBNP's systems and components have been evaluated for plant license renewal. Plant systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

2.2.5.2 Technical Evaluation

Introduction

Engineered safety features at PBNP Station are designed for both seismic and dynamic events as described in FSAR Sections 3.1,Reactor, Design Basis, 5.1, Containment System Structure, 6.1, Engineered Safety Features, Criteria, and Appendix A5, Seismic Design Analysis. FSAR Appendix A5, Seismic Design, provides the general requirements for seismic design. FSAR Section 14.1, Safety Analysis, Core and Coolant Boundary Protection Analysis, includes discussions regarding safety analysis of accident conditions. FSAR Section 7.1, Instrumentation and Control, Introduction and 8.0, Introduction to the Electrical Distribution System, describes the seismic qualification of safety-related instrumentation and electrical equipment respectively. FSAR Section 15.4.6, Aging Management Program Descriptions, Evaluation of Time-Limited Aging Analyses - Environmental Qualification of Electrical Equipment, provides details regarding environmental qualification of safety-related electrical equipment.

Description of Analyses and Evaluations

Seismic input and qualification requirements for safety-related equipment are not affected by EPU. Quality Assurance requirements related to 10 CFR 50, Appendix B are also not affected by EPU. Effects of changes in pressure, temperature and fluid flow on safety-related equipment, component and supports have been found to be within the rated capacity or have been evaluated to comply with the appropriate qualification requirements. Subsequent modifications to the Main Steam and Feedwater systems resulting from EPU are addressed in LR Section 2.2.2.2, BOP Piping, Components & Supports (NSSS Aux. System).

Dynamic effects of internally and externally generated missiles under EPU have been evaluated and are addressed in LR Section 2.5.1.2, Missile Protection. Dynamic effects of pipe-whip and jet impingement under uprate conditions have been evaluated and are addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures. Based on these evaluations, EPU will have no adverse impact on essential equipment as a result of pipe whip, jet impingement, or internal and external missiles.

The Auxiliary Feedwater (AFW) system is being modified as part of the plan to implement EPU. The existing turbine-driven AFW pumps remain unchanged by this system modification. Thus, the existing seismic and dynamic effects evaluations for these pumps and the steam supply lines to these pumps will not be affected. New motor-driven AFW pumps and piping will be installed to support plant operation at EPU conditions. Seismic and dynamic effects evaluations will be performed for these pumps and their associated piping as part of the AFW modification process. The AFW system is addressed in LR Section 2.5.4.5, Auxiliary Feedwater System.

The Main Feedwater (FW) system is being modified to install new main feedwater isolation valves as part of the plan to implement EPU. New feedwater isolation valves and piping will be installed to support plant operation at EPU conditions. Seismic and dynamic effects evaluations will be performed for these valves and their associated piping as part of the main feedwater modification process. The main feedwater system is addressed in LR Section 2.5.5.4, Condesate and Feedwater.

Evaluations related to dynamic and environmental effects of the EPU are addressed in the following LR sections:

- NSSS piping and supports – LR Section 2.2.2.1, NSSS Piping, Components and Supports
- Piping and supports – LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports. This LR section addresses modifications to Main Steam and Feedwater pipe supports resulting from EPU.
- Protection against dynamic effects, including PBNP GDC-40 requirements, of missiles, pipe whip and discharging fluids, and Pipe Rupture Locations and Associated Dynamic Effects - LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects
- Environmental qualification of electrical equipment – LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- Protection against turbine missiles and internal missiles - LR Section 2.5.1.2, Missile Protection
- Piping failures – LR Section 2.5.1.3, Pipe Failures

Results

The evaluation of changes in system design configurations that are required for the proposed EPU concluded that safety-related equipment will continue to be protected from seismic and dynamic events, and will continue to meet the PBNP current licensing basis.

There is no change to seismic inputs (amplified response spectra) or seismic loads resulting from EPU. The existing seismic design basis for piping and supports remains valid and unaffected by EPU. Piping and support seismic loadings will continue to meet the PBNP current licensing basis. Therefore, seismic design is not impacted by EPU.

Dynamic qualification of equipment is not impacted since operating conditions such as pressure, temperature, and fluid flow are not changing significantly as a result of EPU, except for the Main Steam and Condensate/Feedwater Systems. Changes in operating conditions are minor and do not impact the ability of essential safety-related equipment to withstand the effects of pipe-whip, jet impingement, or internal and external missiles of equipment in close physical proximity. Current analyses are bounding under EPU conditions with the exception of the Main Steam and Condensate/Feedwater Systems. Modifications to existing or the addition of new pipe whip restraints and/or pipe supports to the Main Steam and Condensate/Feedwater systems are discussed in LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports and LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects. Missile affects are discussed in LR Section 2.5.1.2, Missile Protection and LR Section 2.5.1.3, Pipe Failures.

The modification process will verifiy that the existing seismic and dynamic criteria are applied to any components or piping added by modifications required to support EPU.

Evaluation of Impact on Renewed Plant Operation Licensing Evaluations and License Renewal Programs

With respect to the licensing renewal described in NUREG-1839, EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries.

The changes associated with operating the Plant at EPU conditions do not add any new or previously unevaluated materials to the plant systems.

The plant changes proposed for the EPU have been evaluated to ensure that there are no additions to the scope of non-safety-related SSCs whose failure could prevent the satisfactory accomplishment of a function required by 10 CFR 54.4(a)(1) and (a)(3).

System and component internal and external environments remain within the parameters previously evaluated. No new aging effects requiring Aging Management Review (AMR) are identified.

2.2.5.3 Conclusion

PBNP has evaluated the effects of the proposed EPU on the seismic and dynamic qualification of mechanical and electrical equipment and concludes that PBNP 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 PBNP GDCs 1, 2, 34, and 40, 10 CFR Part 100, Appendix A, and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Piping support modifications will be made, as discussed in the LR Sections reference in the results section above, to meet the current licensing basis seismic requirements. Therefore, PBNP finds the proposed EPU acceptable with respect to the seismic and dynamic qualification of the mechanical and electrical equipment.

2.2.5.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2. American Concrete Institute (ACI) 318-63, SP-10 Commentary on ACI 318-63 Building Code, January 01, 1965

2.2.6 NSSS Design Transients

2.2.6.1 Regulatory Evaluation

Nuclear Steam Supply System (NSSS) design transients are developed for use in the analyses of the cyclic behavior of the NSSS SSCs. To provide the necessary high degree of integrity for them, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the transients resulting from various plant operating conditions. PBNP's review focused primarily on the effects of the proposed EPU on NSSS design parameters that are used in transient analyses, and how those differences in design parameters required revising NSSS design transients.

The NRC's acceptance criteria for this review are based on:

- GDC 1 insofar as it relates to safety-related components being designed, fabricated, erected, constructed, tested and inspected in accordance with the requirements of applicable codes and standards commensurate with the importance of the safety-function to be performed
- GDC 2 insofar as it relates to safety-related mechanical components of systems being designed to withstand seismic events without loss of capability to perform their safety function
- GDC 14 insofar as it relates to the reactor coolant pressure boundary being designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture
- GDC 15 insofar as it relates to the mechanical components of the reactor coolant system being designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences

Specific review criteria are contained in the SRP, Section 3.9.1, and other guidance provided in Matrix 2 of RS-001.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the design basis transient analyses are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The Reactor Coolant System and the Containment System are of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes at the time of construction and good nuclear practice. The concrete structure of the reactor containment conforms to the applicable portions of ACI-318-63 (Reference 2).

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

All piping, components, and supporting structures of the Reactor Coolant System are designed as Seismic Class I equipment. The Reactor Coolant System is located in the containment building whose design, in addition to being a Seismic Class I structure, also considers accidents or other applicable natural phenomena.

All components and supporting structures of the reactor containment are designed so that there is no loss of function of such equipment in the event of maximum potential ground acceleration acting in the horizontal and vertical directions simultaneously, or other extraordinary natural phenomena referred to in the criterion above. The dynamic response of the structure to ground acceleration, based on the site characteristics and on the structural damping, is included in the design analysis. Its structural members have sufficient capacity to accept, without exceeding specified stress limits, a combination of normal operating loads, functional loads due to a loss of coolant accident, and the loadings imposed by the safe shutdown earthquake (SSE).

CRITERION: The reactor coolant pressure boundary shall be designed, fabricated, and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. (PBNP GDC 9)

The Reactor Coolant System, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits. The materials of construction of the pressure boundary of the Reactor Coolant System are protected from corrosion phenomena which might otherwise significantly reduce the system structural integrity during its service lifetime by the use of noncorrosive materials (such as stainless steel) and by the maintenance of proper chemistry control. System conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The system is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME Boiler and Pressure Vessel Code. The system is also protected from overpressure at low temperatures by the Low Temperature Overpressure Protection System.

CRITERION: The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (PBNP GDC 33)

The reactor coolant boundary is shown to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. The operation of the reactor is such that the severity of an ejection accident is inherently limited.

The adequacy of the PBNP NSSS design parameters that are used in transient analyses relative to conformance to the PBNP specific general design criteria (PBNP GDC) are described in FSAR Chapter 1 Section 1.3.1, Overall Plant Requirements, Section 1.3.2, Protection by Multiple Fission Product Barriers, Section 1.4, Quality Assurance Program, Chapter 4 Section 4.1, Reactor Coolant System, Design Basis, Chapter 5 Section 5.1.1, Containment Systems Structure, Design Basis, Chapter 14, Safety Analysis, and Appendix A5.6, Seismic Design and Verification of Modified, New, and Replacement Equipment.

In addition to the evaluations described in the FSAR, the PBNP's NSSS and associated auxiliary system components were evaluated for the continued acceptability and applicability of the design basis transients for the purpose of plant license renewal. The results of that review are found in NUREG-1839, Safety Evaluation Report (SER) Related to the License Renewal of Point Beach Nuclear Plant, Units 1 and 2, December 2005. System and system component materials of construction, operating history and programs used to manage aging effects are documented in the SER. The SER considers the frequency and severity of the operating transients assumed in the design of the SSCs of the PBNP NSSS and associated auxiliary systems over the extended term of the operating license.

2.2.6.2 Technical Evaluation

2.2.6.2.1 Introduction

As discussed in Chapter 4, Reactor Coolant System, of the FSAR, the systems, structures and components important to safety in the Reactor Coolant System (RCS) are designed to withstand the effects of the cyclic loads from the RCS temperature and pressure changes. These cycling loadings are the results of the normal unit loading and unloading, reactor trips and startup and shutdown operations and other postulated transients. This evaluation compares the PBNP design parameters for the proposed Extended Power Uprate (EPU) to the design parameters used in the current design basis transients. Where revisions were necessary, analyses or evaluations were performed and the transient revised as needed to reflect the design conditions for the proposed EPU.

As part of the original design and analyses of the Nuclear Steam Supply System (NSSS) components for PBNP Units 1 and 2, NSSS design transients (i.e., temperature and pressure transients) were specified for use in the analyses of the cyclic behavior of the NSSS components. These original design transients were subsequently evaluated and revised, as needed, for the replacement steam generators, Measurement Uncertainty Recapture and the plant life extension to 60-year programs. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients selected for use in component fatigue analyses are representative of operating conditions which, when used as a basis for component fatigue analysis, provide confidence that the component is appropriate for its application over the operating license period of the plant.

2.2.6.2.2 Input Parameters and Assumptions

NSSS design transients are based primarily on the NSSS design parameters for the proposed EPU as presented in Licensing Report (LR) Section 1.1, Nuclear Steam Supply System Parameters. The key design parameters upon which the current applicable NSSS design transients are based were compared to the design parameters for the EPU and are shown to be different in RCS vessel average temperature, steam pressure and feedwater temperature. The differences are primarily due to the revised RCS vessel average temperature window and feedwater temperature window. These differences required an assessment of the current NSSS design transients. Where appropriate, revised NSSS design transients for the EPU were developed.

2.2.6.2.3 Description of Analyses and Evaluations

The PBNP design parameters for the proposed EPU were compared to the design parameters used in the current design transients. Where revisions were necessary due to differences in the design parameters, current NSSS design transients were analyzed or evaluated at EPU conditions. As shown in Table 2.2.6-1, List of Design Basis NSSS Design Transients, all transients noted as "yes" (except # 8, steady-state initial fluctuations and # 10, boron concentration equilibrium) that were revised for EPU were analyzed using the LOFTRAN computer code (Reference 1). The steady-state initial fluctuations and the boron concentration equilibrium transients were evaluated and revised to reflect the EPU conditions. The remaining transients evaluated at EPU conditions were determined to be bounded.

2.2.6.2.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The NSSS design transients considered for License Renewal analyses are only impacted if there is some plant change associated with EPU that results in a change in plant operating conditions (i.e., design condition T-hot, T-cold, RCS/pressurizer pressure, steam generator steam pressure, or feedwater temperature). Since the numbers of cycles remain the same for EPU (i.e., valid for

60 years) and there are no significant changes to plant operating methods or procedures, then the transient set considered for plant license renewal remains applicable for EPU. Any changes to the design transient responses are provided within the LR sections that evaluate the components of concern.

2.2.6.2.5 Acceptance Criteria

The acceptance of the revised design transients for each component is determined by the component stress and fatigue analyses discussed in LR Section 2.2, Mechanical and Civil Engineering.

2.2.6.2.6 Results

A list of NSSS design transients with their associated frequencies of occurrences applicable to PBNP is shown in Table 2.2.6-1. The transients listed and their associated frequencies of occurrence are unchanged from those in the current design basis list. The revised design transients parameters are determined at the proposed EPU conditions for use in the component stress and fatigue analyses as discussed in LR Section 2.2, Mechanical and Civil Engineering. Consistent with the current NSSS design transients, the revised NSSS design transient parameters for EPU are conservative representations of transients that, when used as a basis for component fatigue analyses, provide confidence that the component is appropriate for its application over the plant operating life of 60 years.

2.2.6.3 Conclusions

PBNP has reviewed the evaluation of the effects of the EPU on the NSSS design transients and concludes that the required design transient revisions have been adequately addressed. PBNP further concludes that the revised NSSS design transients have been incorporated into the transient analysis of the safety-related NSSS systems and components and that the plant will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1, 2, 9, and 33 following implementation of the EPU. Therefore, PBNP finds the EPU acceptable with respect to the NSSS design transients.

2.2.6.4 Reference

1. WCAP-7907-PA, LOFTRAN Code Description, April 1984

2. American Concrete Institute (ACI) 318-63, SP-10 Commentary on ACI 318-63 Building Code, January 01, 1965

Table 2.2.6-1
List of Design Basis NSSS Design Transients

Transient Description	Number of Occurrences[a] for 60-year Units 1 and 2	Transient Revised due to EPU
1. Plant heatup at 100°F per hour	200	No
2. Plant cooldown at 100°F per hour	200	No
3. Unit loading at 5% of full power per minute	18,300[1]	Yes
4. Unit unloading at 5% of full power per minute	18,300[1]	Yes
5. Step load increase of 10% of full power	2000	Yes
6. Step load decrease of 10% of full power	2000	Yes
7. Large step load decrease with steam dump	200	Yes
8. Steady-state fluctuations		
Initial fluctuations	1.5×10^5	Yes
Random fluctuations	5.0×10^6	No
9. Feedwater cycling at hot standby	25,000 (Unit 1)[2] 10,000 (Unit 2)[2]	No
10. Boron concentration equilibrium	23,360	Yes
11. Loss of load	80	Yes
12. Loss of power	40	Yes
13. Loss of flow	80	Yes
14. Reactor trip from full power	400	Yes
15. Inadvertent auxiliary spray	10	No
16. Turbine roll test	10	No
17. Primary side hydrostatic test, pressure 3106 psig (Unit 1), 3107 psig (Unit 2), temperature cold	5	No
18. Primary side hydrostatic test, pressure 2485 psig, temperature 400°F	94	No
19. Secondary side hydrostatic test	5	No

Table 2.2.6-1
List of Design Basis NSSS Design Transients

Transient Description	Number of Occurrences[a] for 60-year Units 1 and 2	Transient Revised due to EPU
20. Primary-to-secondary leak test	27	No
21. Secondary-to-primary leak test	128	No

Notes:

a. For equipment design purposes (NRC SE dated 12/2005, NUREG-1839).

1. For all components except for pressurizer and reactor vessel internal baffle former bolts. For pressurizer 11,600 (consistent with FSAR Table 4.1-8) and for reactor vessel internals baffle former bolts 3545.
2. All components except reactor vessel. 2000 for reactor vessel for Units 1 and 2 (consistent with FSAR Table 4.1-8).

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

2.3.1.1 Regulatory Evaluation

Environmental Qualification of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from Design Basis Accidents. The PBNP review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation including anticipated operational occurrences, and design bases accidents. The PBNP review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed EPU.

The NRC's acceptance criteria for environmental qualification of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for 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.

PBNP Current Licensing Basis

The environmental qualification program is embedded in procedures for design, installation, and maintenance of systems and components.

IE Bulletin 79-01B transmitted the, Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors, (Division of Operating Reactor (DOR)) for evaluating environmental qualification and for identifying safety-related equipment for which environmental qualification was to be addressed. PBNP provided several submittals concerning Environmental Qualification of Safety Related Electrical Equipment for the PBNP Units 1 and 2. The NRC concluded that the Environmental Qualification Program complied with 10 CFR 50.49 and the NRC issues were satisfactorily resolved in the NRC SER dated August 30, 1984.

FSAR Section 7.3.3.7, Environmental Qualification of Protection System Equipment, summarizes the environmental qualification of protection system equipment and FSAR Section 7.3.3.8, Environmental Qualification of ESF Equipment, summarizes the environmental qualification of ESF equipment.

PBNP has submitted LAR 241, Alternative Source Term (ML083450683), as outlined in 10 CFR 50.67 and Regulatory Guide 1.183 for post accident dose assessments associated with the site boundary, and on-site locations that require continuous occupancy such as the Control Room. The source terms used to establish post-accident radiation and vital area access environments were not impacted by LAR 241.

In addition to the evaluations described in the FSAR, PBNP's systems and components have been evaluated for plant license renewal. Plant systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the PBNP, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the environmental qualification of electrical equipment is covered in the Time-Limited Aging Analysis Section 4.8.

The Cable Condition Monitoring Program was established specifically for license renewal. As described in FSAR Section 15.2.8, Cable Condition Monitoring Program, this program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The program requires visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation. The scope of this program includes accessible non-EQ electrical cables and connectors, including I&C circuit cables. Although the scope of this program is aimed at non-EQ electrical cables and connectors, it is equally applicable to EQ electrical cables, since no distinction is made as to whether the cables being inspected are EQ or non-EQ.

2.3.1.2 Technical Evaluation

Introduction

Safety-related structures, systems and components (SSCs) at PBNP are designed for environmental events as described in FSAR Section 1.0, Introduction and LR Section 2.2.5, Seismic and Dynamic Qualification of Mechanical and Electrical Equipment.

The constituent parts of the EQ Program include the program basis, verification of equipment operability during and following exposure to plant environmental conditions, and proper installation and maintenance of equipment in the plant. These elements are controlled through a set of administrative documents consisting of a program description, implementing procedures, and reference documents.

The following PBNP documents are used to manage the EQ Program:

NP 7.7.1, Environmental Qualification of Electrical Equipment, provides administrative control of activities performed when Environmental Qualification (EQ) of electrical equipment is required to comply with 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.

DG-G11, Environmental Qualification Service Conditions (ESC), summarizes the available data regarding the specific environmental parameters (i.e., temperature, radiation, etc.) for each specific plant location as a result of normal, abnormal and accident operating conditions. The ESC provides a single source of design basis references for the environmental data used in the EQ Program. This document also implements a commitment to the NRC to manage the effects of aging for systems and components within the scope of license renewal.

As described in NP 7.7.1, EQ documentation is controlled under the PBNP Quality Assurance (QA) program. EQ files are retained in an auditable form for the duration of the installed life of the component. EQ documentation includes:

- Master List of Electrical Equipment to be Environmentally Qualified (EQML)
- Equipment Qualification Checklists (EQCK)

- Equipment Qualification Summary Sheets (EQSS) which are historical documents that are no longer used
- Equipment Qualification Maintenance Requirement Sheets (EQMR)
- Supporting documentation references (e.g., test report etc.)

The evaluations for EPU conditions demonstrate the continued qualification of the equipment or identifies the requirement for equipment upgrades or changes to ensure the margins required by the Institute of Electrical and Electronic Engineers (IEEE) 323-1974 and the PBNP Equipment Qualification Program are maintained. The acceptance criterion is the continued qualification of the equipment under the requirements of 10 CFR 50.49.

Description of Analyses and Evaluations

Radiation Environments

The current normal operation dose estimates utilized for equipment qualification inside containment are based either on survey data scaled up to 1683 MWt, or on radiation source terms corresponding to a core power level of 1683 MWt, an 18 month fuel cycle and 1% fuel defects. For outside containment, the environmental dose estimates are based on plant survey data scaled up to 1683 MWt. With the exception of a few selected components, the current integrated doses are based on 40 years of normal operation and reflect an assumed capacity factor of 100%.

PBNP is currently in the process of updating its post-accident dose assessments associated with the site boundary and on-site locations that require continuous occupancy, such as the Control Room to reflect Alternative Source Terms (AST) as outlined in 10 CFR 50.67, and Regulatory Guide 1.183. However, the EPU assessment for the post-LOCA integrated doses for equipment qualification continues to be based on the original licensing basis (TID-14844 Source Terms). This approach is acceptable per Section 1.3.5 of Regulatory Guide 1.183 which indicates that although EQ analyses impacted by plant modifications associated with AST implementation should be updated to address the impacts, no plant modification is required to address the impact of the difference in source term characteristics (i.e. AST vs TID 14844) on EQ doses.

The current accident dose estimates used for equipment qualification for locations inside and outside containment are based on a core power level of 1683 MWt, an 18 month fuel cycle, and with the exception of a few selected components, an integration period of one year. The accident that controls post-accident environments is the LOCA. The radiation source terms used reflect the conservative assumptions of NUREG-0578, i.e., following a LOCA, 100% of the core noble gases, 50% of the core halogens and 1% of the core remainder are assumed to be instantaneously available and homogeneously mixed in the containment atmosphere and in the sump water.

The EPU will typically increase the radioactivity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing radioactive fluids, and the corresponding radiation zone doses, will increase accordingly. Additional factors that impact the equilibrium core inventory and consequently, the estimated dose, are fuel enrichment and burn up.

The normal service condition radiation levels are updated for the EPU utilizing plant survey data, and take into account a 60 year plant life to reflect life extension. The survey data at the current plant power level is adjusted by the EPU core power scaling factor. Due to the EPU, the core power level will increase from 1540 MWt to 1810.8 MWt which includes 0.6% uncertainty (conservatively assumed to be approximately 20% for purposes of analyses). Since the units went on line in 1970 and 1973, the 60-year normal operation doses are estimated reflecting the past 35 years (conservatively based on Unit 2) at the dose rate listed in the survey data, and 25 years at the EPU power level. An additional 10% factor is included in order to account for uncertainty in the survey dose rate values.

The impact of EPU on the accident environmental dose estimates is developed using scaling techniques that reflect a comparison of the source terms developed based on the core inventory utilized in the original analyses of record, to the corresponding source terms developed using the EPU core inventory. Since the relative abundance of each isotope and the average gamma energy of each isotope are the key parameters that affect direct exposure, having a scaling factor that addresses the change in these parameters is sufficient to assess the radiological impact of the EPU. Consideration is given to the fact that dose scaling factors will vary with radiation source, time after accident, as well as shielding, therefore bounding values are utilized.

The EPU core inventory is based on a core power level of approximately 1811 MWt (includes a power uncertainty of 0.6%) and an 18-month fuel cycle. In addition to the EPU power level, the estimated change in radiation levels, reflect the following:

1. Use of an additional 4% margin in the EPU core inventory to address potential future fuel cycle variability.

2. Use of post-LOCA radiation source term guidance provided in NUREG-0737, Clarification of TMI Action Plan Requirements (specifically in Section II.B.2, Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems which maybe used in Post Accident Operations), and repeated below:

   a. Containment Atmosphere Source: 100% core noble gases and 50% core halogens are assumed to be instantaneously available and homogeneously mixed in the containment atmosphere (instead of the conservative assumption currently used of 100% core noble gases, 50% core halogens and 1% core remainders instantaneously available and homogeneously mixed in the containment atmosphere).

   b. Sump water Source: 50% core halogens and 1% core remainders are assumed to be instantaneously available and homogeneously mixed in the sump fluid (instead of the conservative assumption currently used of 100% core noble gases, 50% core halogens and 1% core remainders instantaneously available and homogeneously mixed in the sump fluid).

As a result, the calculated EPU dose scaling factor values are different from just the simple EPU/Pre-EPU power level ratio.

Results - Radiation

The normal operation service radiation doses inside and outside containment are increased due to the EPU and life extension. Except as noted, the estimated post-accident radiation doses inside and outside containment remain bounded by the current values due to the change in source terms from NUREG-0578 to NUREG-0737. The only exception is in the containment facade, see Table 2.3.1-4, EPU Impact on Containment Facade Environmental Parameters. Revised total integrated doses in each environmental zone that combine normal operation service conditions with the DBA have been compared to the original qualification value.

Additional detailed analysis will be performed to qualify the following components for EPU conditions or they will be replaced with qualified components prior to the implementation of EPU:

- EQCK-HONEYW-001: Four (4) Honeywell Microswitches;Containment Façade, -10' EL, [1(2) POS-00850A, 1(2) POS-00850B], RHR Pump Sump B Suction Position Switch
- EQCK-PANEL-001: One (1) Nutherm Panel; PAB, outside charging pump cubicle. [1 N-11], Charging Pump/PZR Heater Local Control Station

Inside Containment Evaluation

With the exception of radiation and temperature, normal service conditions and operational occurrences (that is, for pressure and humidity) do not change. The normal operation radiation environments are increased to reflect the EPU and life extension to 60 years.

There is no change in the normal operating design basis temperature for containment (HVAC cooling) as a result of the EPU. Since the weighted average annual temperature is less than the design temperature, this change will have no impact on design temperature. The normal containment temperature increases less than 1°F.

The estimated post accident radiation doses inside containment remain bounded by current values due to the change in source terms from NUREG 0578 to NUREG 0737. The EPU DBA containment analysis demonstrates that the LOCA equipment qualification peak temperature is bounded by the Composite EQ Profiles as shown on Figure 2.3.1-1 with margin as defined in IEEE 323-1974. The Composite EQ profile is a composite profile developed from individual equipment EQ qualification profiles and is used to screen the impact of the new accident curves and provide a graphic representation of the current qualification values against the new accident curves.

The Double Ended Hot leg (DEHL) Reactor Coolant System (RCS) break had the highest temperature while the Double Ended Pump Minimum Safety Injection (DEPMINSI) and Double Ended Pump (DEPMAXSI) had longer durations. The peak MSLB temperature is higher than the peak LOCA temperature (284.4°F vs. 279.9°F, but for shorter duration, 600 seconds). However, both remain bounded by the peak Composite EQ Profile temperature of 311°F for 3,600 seconds.

The LOCA and long-term temperature profile for the Post Accident Operability Time (PAOT) is also lower than the typical Composite EQ profile as shown on Figure 2.3.1-1.

The LOCA pressure curve is also lower than the current plant EQ pressure curve, as shown on Figure 2.3.1-2. The Double Ended Hot leg (DEHL) Reactor Coolant System (RCS) break had the highest pressure of 70.05 psia; the Double Ended Pump Minimum Safety Injection

(DEPMINSI) and Double Ended Pump (DEPMAXSI) had longer durations, but slightly lower peak pressures of 67.7 psia and 67.9 psia respectively. The Composite EQ Profile pressure is at 74.7 psia, as shown on Figure 2.3.1-2. The peak MSLB pressure is higher than the peak LOCA pressure (73.4 psia vs 70 psia). However, both remain bounded by the peak Composite EQ Profile pressure of 74.7 psia.

Pressure effects are generally stress-related rather than age degradation related. Qualification to the high-pressure peak ensures that there are no stress related component failures. For the EPU LOCA temperature and pressure impact, the post-accident operating time has been evaluated and found acceptable.

The submergence level inside containment increases only slightly due to increased temperature at EPU, but is essentially unchanged from the pre-EPU evaluation of 15'-2" (Elevation of Sump B is El.8') and no EQ equipment is affected by this slight change.

Other parameters that affect the qualification of equipment are humidity and chemical spray and they will not change due to EPU.

Results – Inside Containment, LOCA

The results of the LOCA and MSLB comparison shows that all the Equipment Qualification Program electrical equipment will continue to be qualified at the EPU conditions, and thus will continue to meet the requirements of 10 CFR 50.49. Table 2.3.1-1 shows the changes in the plant parameters evaluated for EPU.

Outside Containment Evaluation

Normal service conditions and operational occurrences for temperature, pressure, and humidity do not change following implementation of the EPU. The normal radiation dose for some rooms and cubicles will increase slightly to account for the EPU and for life extension to 60 years.

With the exception of the containment facade, the estimated post-accident radiation doses outside containment remain bounded by the current values due to the change in source terms from NUREG-0578 to NUREG-0737. Revised total integrated doses in each environmental zone that combine normal operation service conditions with the DBA have been compared to the original qualification value. The results of the comparison shows that all the electrical equipment in the EQ Program will continue to be qualified at the EPU conditions and thus will continue to meet the requirements of 10 CFR 50.49., with the exception of the Honeywell microswitches and no Therm panel.

The high energy line break (HELB) evaluation was reconstituted, including HELB methodology and results, as discussed in LR Section 2.5.1.3, Pipe Failures. Environmental conditions resulting from the reconstituted HELB evaluations were included in the EQ evaluation for EPU. The equipment required to respond to, monitor, or mitigate each HELB event was also reviewed in the reconstitution effort and included in the EQ program.

Results - HELB

Based on the resulting environmental conditions for HELB events at EPU, all equipment currently in the EQ program remains qualified.

Only one HELB area contains equipment that requires inclusion in the EQ program, the lower elevation of the containment facade. The items are:

1(2) LT-972	Refueling Water Storage Tank Level (post accident monitoring)	
1(2) LT-973	Refueling Water Storage Tank Level (post accident monitoring)	
1(2) CS-2042-S	SOV for AOV MS-2042, SG 1A & 2A	Blowdown Header Control Valve (isolation)
1(2) CS-2045-S	SOV for AOV MS-2045, SG 1B & 2B	Blowdown Header Control Valve (isolation)

Review of these items indicates that they are the same model type as those presently in the EQ files, and as such, can be qualified to the reconstituted HELB conditions and will be documented in the EQ program prior to EPU implementation. Table 2.3.1-2, EPU Impact on Primary Auxiliary Building Environmental Parameters, Table 2.3.1-3, EPU Impact on Turbine Building Environmental Parameters, and Table 2.3.1-4, EPU Impact on Containment Facade Environmental Parameters, show the changes in the plant parameters evaluated for EPU.

2.3.1.3 Conclusions

PBNP has performed an assessment of the effects of the proposed EPU on EQ of electrical equipment and concludes that the assessment has adequately addressed the affects of EPU on the environmental conditions for and the qualification of electrical equipment. PBNP further concludes that the electrical equipment will continue to meet the PBNP current licensing basis requirements following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the Environmental Qualification of electrical equipment.

2.3.1.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.3.1-1
EPU Impact on Containment EQ Parameters

Plant Condition	Parameter	Current EQ Parameters	EPU Results	Change
Normal Operation	Temperature	135 °F	135 °F	0 °F
Accident (LOCA)	Temperature	291 °F	279.9 °F	(-)11.1 °F
Accident (MSLB)	Temperature	285.0 °F	284.4 °F	(-) 0.6 °F
Post Accident	Temperature (at 24 hours)	210 °F	156.2 °F	(-) 53.8°F
Normal Operation	Pressure	0 psig	0 psig	0 psig
Accident (LOCA)	Pressure	60 psig	55.35 psig	(-) 4.65 psi
Accident (MSLB)	Pressure	59.8 psig	58.67 psig	(-) 1.33 psi
Normal Operation	Humidity	10-90%	10-90%	0%
Accident	Humidity	100%	100%	0%
Post Accident	Humidity	100%	100%	0%
Normal Operation	Radiation (gamma only)	2.3E7 Rads (40 yrs)	2.85E7 Rads (60 yrs)	+ 0.55 E7
Accident	Radiation (gamma + beta)	2.8E8 Rads	2.42E8 Rads	(-) 0.38 E8
Accident plus Normal (TID)	Radiation (gamma + beta)	3.03E8 Rads	2.71E8 Rads	(-) 0.32 E8
Accident	Spray pH	7.0 - 10.5	7.0 - 10.5	No Change
Accident	Submergence	14'-10" elevation level	15'-2" elevation level	+ 4 inches

Table 2.3.1-2
EPU Impact on Primary Auxiliary Building Environmental Parameters

Plant Condition	Parameter	Pre-EPU	EPU	Change
Normal Operation	Temperature	104.5 °F	104.5 °F	0 °F
Accident (30" MS crack)	Temperature	309.5 °F	363 °F	(+) 53.5 °F
Post Accident	Temperature (at 24 hours)	104.5 °F	104.5 °F	0 °F
Normal Operation	Pressure	0 psig	0 psig	0 psig
Accident	Pressure	0.45 psig	0.67 psig	+ 0.22 psig
Normal Operation	Humidity	10-90%	10-90%	0%
Accident	Humidity	100%	100%	0%
Post Accident	Humidity	100%	100%	0%
Normal Operation	Radiation (gamma)	400 Rads (40 yrs)	6.3E5 Rads (60 yrs)	(+) 6.26E5 Rads
Accident	Radiation (gamma)	1.31E7 Rads	1.16E7 Rads	(-) 0.15 Rads
Accident plus Normal (TID)	Radiation (gamma)	1.31E7 Rads	1.22E7 Rads	(-) 0.09E7 Rads
Accident	Submergence / Flood	N/A	N/A	N/A

Table 2.3.1-3
EPU Impact on Turbine Building Environmental Parameters

Plant Condition	Parameter	Pre-EPU	EPU	Change
Normal Operation	Temperature	100.5 °F	100.5°F	0 °F
Accident	Temperature	314 °F	243 °F	(-)71 °F
Post Accident	Temperature (at 24 hours)	90 °F	90 °F	0 °F
Normal Operation	Pressure	0 psig	0 psig	0 psia
Accident	Pressure	1 psig	0.5 psig	(-) 0.5 psig
Normal Operation	Humidity	10-70%	10-70%	0%
Accident	Humidity	100%	100%	0%
Post Accident	Humidity	100%	100%	0%
Normal Operation	Radiation (Gamma)	400 Rads (40 yrs)	1300 Rads (60 yrs)	No impact, remains mild
Accident	Radiation (Gamma)	N/A	N/A	No impact, remains mild
Accident plus Normal (TID)	Radiation (Gamma)	400 Rads	1300 Rads	No impact, remains mild
Accident	Submergence/ Flood	N/A	N/A	N/A

Table 2.3.1-4
EPU Impact on Containment Facade Environmental Parameters

Plant Condition	Parameter	Pre-EPU	EPU	Change
Normal Operation	Temperature	85 °F	85 °F	0 °F
Accident	Temperature	298 °F	200 °F	(-) 98 °F
Post Accident	Temperature (at 24 hours)	85 °F	85 °F	0 °F
Normal Operation	Pressure	0 psig	0 psig	0 psig
Accident	Pressure	1 psig	0.561 psig	(-) 0.439 psig
Normal Operation	Humidity	10-70%	10-70%	0%
Accident	Humidity	100%	100%	0%
Post Accident	Humidity	100%	100%	0%
Normal Operation Note 2	Radiation (Gamma)	1.14E3 Rads (40 yrs)	1.70E3 Rads (60 yrs)	+ 0.56E3
Accident	Radiation (Gamma)	1.45E6 Rads	7.6E6 Rads	+ 6.15E6 Rads
Accident plus Normal (TID)	Radiation (Gamma)	1.45E6 Rads	7.6 E6 Rads	+ 6.15E6 Rads
Accident	Submergence / Flood	N/A	N/A	N/A

Figure 2.3.1-1
LOCA vs. Plant EQ Profile

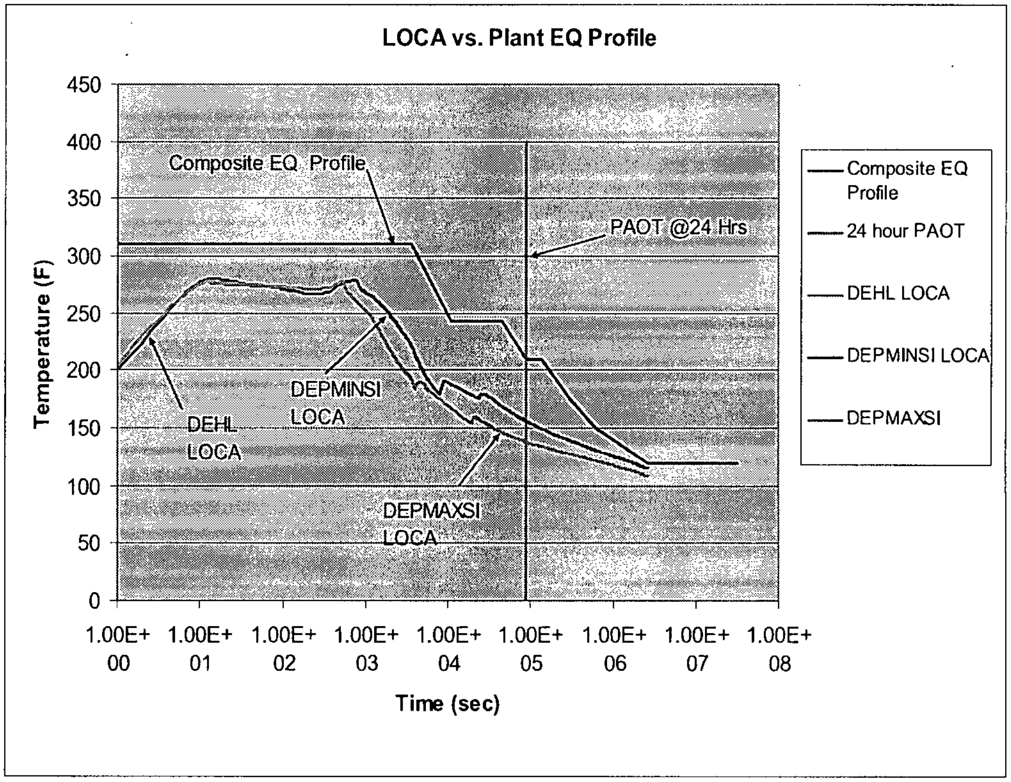
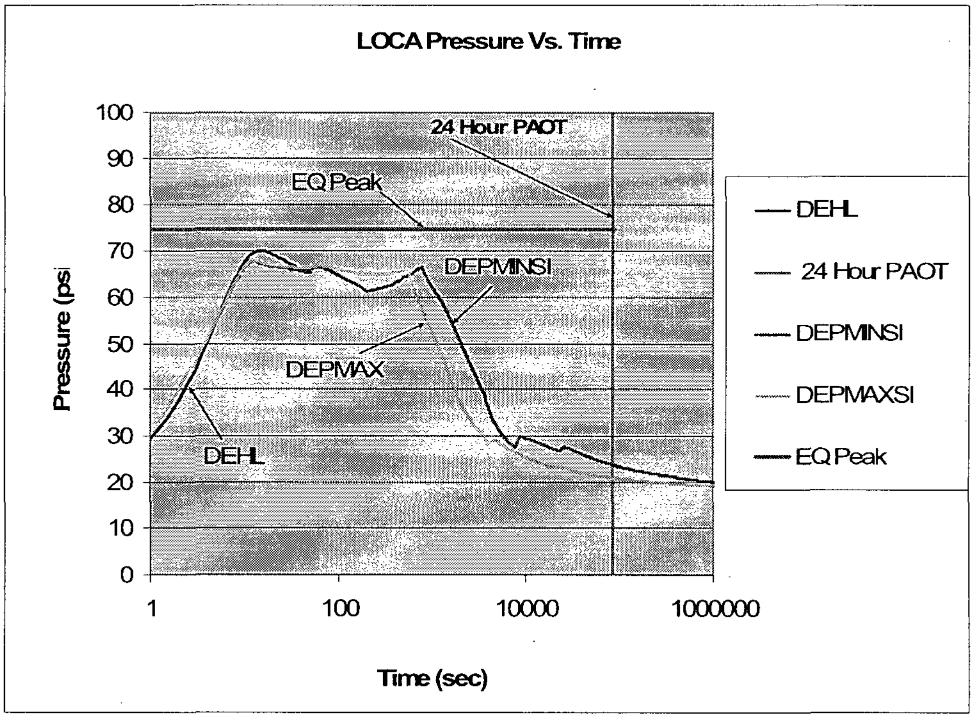


Figure 2.3.1-2
LOCA Pressure Vs. Time



2.3.2 Offsite Power System

2.3.2.1 Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The PBNP review covered the descriptive information, analyses, and referenced documents for the offsite power system, as well as the stability studies for the electrical transmission grid. The PBNP review focused on whether the loss of the nuclear unit, the largest operating generating facility on the grid, or the most critical transmission line will result in the loss-of-offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC 17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, and Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

PBNP Current Licensing Basis

As noted in the Final Safety Analysis Report (FSAR) Section 1.3, the GDC used during the licensing of PBNP predate those provided today in 10 CFR 50 Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 17 is as follows:

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (PBNP GDC 39)

As described in FSAR Section 8.1, 345kV AC Electrical Distribution System (345kV) does not perform any safety related function and is classified as non-safety related. The 345kV distribution system performs the following functions:

1. Transmits power generated at PBNP to the 345kV grid
2. Provides standby power to PBNP auxiliaries during unit(s) startup, shutdown, and after reactor trip
3. Provides a reliable source of normal power to PBNP engineered safeguards equipment
4. Acts as an interconnecting terminal for the four 345kV lines at PBNP

FSAR Section 8.1.3, System Evaluation, discusses the required analysis to ensure the offsite power system remains stable. The section states that analysis of the interconnected 345kV system must show that a fault on any one of the four transmission lines or any bus section at Point Beach, or the loss of both Point Beach units will not cause a cascading failure of the 345kV transmission system, provided all four transmission lines and five bus sections at Point Beach are in service. Additional studies show that when one or more of the transmission lines is out of service, there is a potential for cascading failure of the transmission system, given the loss of one of the remaining transmission lines or the occurrence of a fault on one of the remaining transmission lines or any bus section at Point Beach. Operating procedures have been developed and implemented which limit the operation of the Point Beach Units, such that a cascading failure of the transmission system described above will be minimized.

FSAR 8.1.3 also states that comprehensive studies of the interconnected transmission network in the Mid-America Interconnected Network (MAIN) under contingency conditions have been made. These studies showed that the sudden loss of any single unit, including the nearby Kewaunee unit, will not affect the ability of the transmission system to supply power to the Point Beach Nuclear Plant auxiliary systems.

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power. To ensure continuity of power to safety related loads during plant transients the safety related buses are normally powered from offsite power (through the high voltage and low voltage station auxiliary transformers).

In addition to the evaluations described in the FSAR, the offsite power system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- License Renewal Safety Evaluation Report for the PBNP Nuclear Power Plant, (NUREG-1839), dated December 2005 (Reference 1.)

The above SER, determined portions of the offsite power system are within the scope of the license renewal. Components subject to age management review are evaluated on a plant wide basis as commodities, where the generic commodity groups are described in SER Section 2.5 and aging management is described in SER Section 3.6.

2.3.2.2 Technical Evaluation

2.3.2.2.1 Introduction

The offsite power system and its components are discussed in the FSAR Section 8.1.2, System Description and Operation. The system consists of four lines connected to the plant switchyard. Each line is carried on a separate line structure in order to minimize the possibility of fault propagation due to lightning or other physical damage. The output of the units main generators are connected to the 345kV system through the main generator output breakers and the generator step up transformers (1/2-X01). The 345kV system supplies the high voltage auxiliary transformers (1/2-X03) which are used to supply sufficient power to each unit for associated safeguards equipment. The normal supply for auxiliary loads, associated with the plant engineered safeguards, is the 345kV system. The auxiliary electrical system functions to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation. One of the four 345kV transmission lines can supply all the plant auxiliary power.

An initial Interconnection System Impact Study report was performed for Midwest Independent System Operator (MISO) by American Transmission Company (owner of the local grid) to evaluate the impact of increased electrical output of PBNP on the reliability of the local 345kV transmission system and MISO bulk power systems. The report is being transmitted to NRC for information under a separate letter. Note that this study is being revised based on updated design input for the main generator ratings and outputs from the generator excitation model planned to support the EPU.

The function of the 345kV Switchyard, is to interconnect the station output to the transmission grid, and provide two independent offsite power sources to the station high voltage auxiliary transformers (1/2X-03).

The function of the generator step up transformers (1/2X-01) for each unit is to provide a means to transmit the generator output power to the switchyard by stepping up the generator voltage from 19kV to the switchyard voltage of 345kV. New main generator output breakers will be provided to isolate the generator from the distribution system when generator trips are required. This allows the existing 345kV breakers, F52-122 and F52-142, to remain closed to feed auxiliary power to the plant's AC auxiliary system via the Unit Auxiliary Transformers (UAT, 1/2X-02) after a generator trip. The 1/2A-01 and 1/2A-02 buses will remain powered from the 345kV system for any plant transients other than a loss of 1/2X-01, 1/2X-02, or main generator breaker. Installation of this modification on each unit is tracked as a commitment in Attachment 4, Item 6.

The function of the 345kV lines is to deliver the station output power from the generator step up transformer to the switchyard and also provide power from the switchyard to high voltage station auxiliary transformers 1/2X-03. These lines will also supply grid power to the 1/2X-02 Unit Auxiliary Transformers during unit shutdown following EPU implementation.

The function of the two separate three-phase high voltage station auxiliary transformers (HVSAT) 1/2X-03 is to step down the offsite voltage from 345kV to 13.8kV and power the 13.8kV system during all conditions except during a station blackout or plant fire. The HVSAT also provides a means to transmit the output power from the station gas turbine (G-05) to the switchyard.

2.3.2.2.2 Description of Analyses and Evaluations

The offsite power system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. This evaluation is based on the system's required design functions and attributes, and upon a comparison between the existing equipment ratings and the anticipated operating requirements at EPU conditions. Continuing analysis of the PBNP associated transmission system grid stability is being monitored as a commitment for this LAR submittal as indicated in Attachment 4. Updates to the study will be evaluated if a revised grid study analysis is recieved.

2.3.2.2.3 Results

2.3.2.2.3.1 Grid Stability

The transmission system is discussed in FSAR Section 8.1, 345kV AC Electrical Distribution System (345kV). An initial Interconnection System Impact Study Report was performed to evaluate the impact of the PBNP EPU on the reliability of the local 345kV and MISO bulk power systems. Thermal, voltage, stability, and circuit breaker fault duty results, with and without PBNP at EPU, were compared to determine any detrimental impact of the proposed EPU. NERC

(North American Electric Reliability Corporation) pre-contingency and contingencies were evaluated with load flow analysis. This analysis involved an extensive examination of contingencies of local and cross-state transmission facilities located around the PBNP plant area. A contingency as defined by NERC. The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. The Interconnection Study Impact Report will also evaluate the possibility of cascading failures as discussed in section 8.1.3 of the FSAR.

The initial analysis determined that voltage levels and breaker duty remain adequate after the implementation of the EPU. However, there are thermal and stability limits that will be exceeded by the implementation of the PBNP EPU. These initial issues can be resolved by a combination of breaker protection improvements, installation of a switching station, line segment upgrades, and operating restrictions. Interim conditions are being identified by PBNP and American Transmission Company (ATC) to allow PBNP to operate at EPU conditions prior to the completion of all of the final required system upgrades. These interim conditions are tracked as commitment of Attachment 4.

The results of the initial study indicate that with a combination of system upgrades along with operating restrictions, the thermal, voltage, and stability performance of the 345kV system will not be degraded by implementation of the EPU. Continuing analysis of the PBNP associated transmission system grid study is being monitored as a commitment for this LAR submittal as indicated in Attachement 4. The results of the study will also ensure that EPU will not cause cascading failures as discussed in section 8.1.3 of the FSAR.

2.3.2.2.3.2 Offsite Power System Components

PBNP Owned Portion of 345kV Switchyard

The 345kV circuit breakers and disconnect switches located in the PBNP owned portion of the 345kV switchyard have been evaluated (in addition to the switchyard equipment evaluated in the Interconnection System Impact Study Report) for EPU conditions. The 345kV circuit breakers F52-122 and F52-142, their associated 345kV disconnect switches (F89-112B and F89-142B) were evaluated and proved to be acceptable at EPU conditions.

Generator Step-Up Transformer

The generator step up transformer is discussed in FSAR Section 8.3.2, 19K VAC Electrical Distribution System (19kV). The equipment has been evaluated for EPU conditions. The evaluation confirms that the existing generator step up transformer design rating at 65°C is inadequate to support unit operation at EPU conditions. As a result a modification will be performed to replace the existing step up transformers rated 609 MVA 65°C with new transformers rated 755 MVA at 65°C, which envelops the anticipated worst-case generator step up transformer loading at EPU conditions. Refer to Table 2.3.2-1,GSU Maximum Input loading Unit, for worst-case loading and rating comparison. The required modifications include replacement of single phase transformers for each unit with new higher rated single phase transformers (1/2 X-01). The modifications will be implemented prior or concurrently with EPU.

The station's ability to use offsite power via the generator step up (1/2-X01) and unit auxiliary transformers (1/2-X02) from the 345kV switchyard will be improved due to the installation of new

19 kV generator output breakers. The installation of the generator output breakers also involves upgrades to improve the protective relaying and monitoring capability to maintain functionality of equipment at EPU output levels. The 345kV monitoring equipment upgrades and protective relay schemes and setting associated with the 345kV switchyard are tracked as commitment 6 in Attachment 4.

Switchyard Cables

The 345kV switchyard cables have been evaluated for EPU conditions. These cables include the tie lines from the generator step up transformers (1/2X-01) to the 345kV switchyard and also the tie lines from the high voltage station auxiliary transformers (1/2X-03) to the 345kV switchyard. The evaluation indicates that the existing tie line design rating is not exceeded by the tie line loading required at EPU.

High Voltage Station Auxiliary Transformers

High voltage station auxiliary transformers 1/2X-03 are discussed in FSAR Sections 8.1, 345kV AC Electrical Distribution System (345kV), and 8.2, 13.8K VAC Electrical Distribution System (13.8kV).The evaluation confirms that the high voltage station auxiliary transformers (1/2X-03) design rating of 37.3 MVA at 55°C (FA) is adequate to support unit operation at EPU conditions. The loading on the high voltage station auxiliary transformers will be reduced under EPU conditions due to the installation of new generator output breakers, which eliminates the fast bus transfer of balance of plant loads to the high voltage station auxiliary transformer after a generator trip. The calculated worst-case transformer loading is shown in Table 2.3.2-2,1X-03 Maximum Input Loading on the H Winding, and Table 2.3.2-3,2X-03 Maximum Input Loading on the H Winding.

Subject to completion of required interim or final grid system upgrades being identified by PBNP and ATC, EPU evaluations have determined that after implementing the modifications and 345kV grid upgrades identified above, the offsite power system will continue to have sufficient capacity and capability to supply power to all safety loads and other preferred operating equipment. Two separate and independent offsite power sources will continue to be maintained in accordance with the PBNP current licensing basis.

License Renewal

As discussed above, portions of the offsite power system are within the scope of license renewal. However, the changes associated with operating the offsite system at EPU conditions do not add any new or previously unevaluated materials to the system, nor require any changes to the Aging Management Program. No new aging effects requiring management are identified.

2.3.2.3 Conclusions

PBNP has assessed the effects of proposed EPU on the offsite power system and concludes that it will adequately account for the effects of the proposed EPU on the system's functional design. PBNP further concludes that the offsite power system will continue to function as designed and continue to meet the requirements of PBNP licensing basis with respect to PBNP GDC 39 and FSAR section 8.1.3 following implementation of the proposed EPU. This conclusion considers the effect of replacements of the generator step up transformers, installation of the generator output breakers, and any interim or final required 345kV system upgrades identified by PBNP and ATC. There is adequate physical and electrical separation and the offsite power system has the capacity and capability to supply power to all safety loads. Subject to implementation of the required system upgrades, the impact of the proposed EPU does not degrade grid stability. Therefore, the proposed EPU is acceptable with respect to the offsite power system.

2.3.2.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.3.2-1 GSU Maximum Input loading Unit

Operating at Lagging Power Factor (Exporting VARs)					
				Rating	
	MW	**MVAR**	**MVA**	**MVA**	**Reference**
Existing	583	172	608.9	655/755 @55°C/65°C (OFAF)	Note 1
EPU	641.6	235	683.3		Note 1,2
Increment	58.6	63	74.4		
Total Input Load	641.6	235	683.3	655/755 @55°C/65°C (OFAF)	
Unit Operating at Leading Power Factor (Importing VARs)					
				Rating	
	MW	**MVAR**	**MVA**	**MVA**	**Reference**
Existing	583	100	608.9	655/755 @ 55°C/65°C (OFAF)	Note 1
EPU	641.6	220	678.3		Note 1,2
Increment	58.6	120	69.4		
Total Input Load	641.6	220	678.3	655/755 @55°C/65°C (OFAF)	

Notes:
1. The existing and EPU main generator output is provided from LR Section 2.3.3, AC Onsite Power System
2. The GSU rating is after specified transformer modifications

Table 2.3.2-2 1X-03 Maximum Input Loading on the H Winding

Primary Winding	H-Winding			Rating	Reference
	MW	MVAR	MVA	MVA	
Existing	33.6	22.1	40.2	28/37.3 @55°C (OA/FA)	Note 1,4
EPU	13.7	7.4	15.5		Note 2,4
Increment	-19.9	-14.8	-24.7		Note 3,4
Total Input Load	13.7	7.3	15.5	37.3@55°C (FOA)	

Notes:

1. Existing loading is derived from load flow/voltage profile analysis. These values represent the present calculated loading on the transformer prior to EPU.
2. EPU+Existing loading is derived from load flow/voltage profile analysis. These values represent the total calculated loading on the transformer after EPU.
3. Increment loading is the difference between the Existing loading (Note 1) and EPU + Existing loading (Note 2). These values represent the additional loading on the transformer as a result of EPU.
4. $MVA = \sqrt{MW^2 + MVAR^2}$

Table 2.3.2-3 2X-03 Maximum Input Loading on the H Winding

Primary Winding	H-Winding MW	H-Winding MVAR	H-Winding MVA	Rating MVA	Reference
Existing	34.1	22.4	38.2	28/37.3 @55°C (OA/FA)	Note 1
EPU	13.4	7.2	15.2		Note 2
Increment	-20.7	-15.2	-23.0		Note 3
Total Input Load	13.4	7.2	15.2	37.3@55°C (FOA)	

Notes:

1. Existing loading is derived from load flow/voltage profile analysis. These values represent the present calculated loading on the transformer prior to EPU.
2. EPU+Existing loading is derived from load flow/voltage profile analysis. These values represent the total calculated loading on the transformer after EPU.
3. Increment loading is the difference between the Existing loading (Note 1) and EPU + Existing loading (Note 2). These values represent the additional loading on the transformer as a result of EPU.
4. $MVA = \sqrt{MW^2 + MVAR^2}$

2.3.3 AC Onsite Power System

2.3.3.1 Regulatory Evaluation

The alternating current (AC) onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems to supply power to safety-related equipment. The PBNP review covered the descriptive information, analyses, and referenced documents for the AC onsite power system. The NRC's acceptance criteria for the AC onsite power system are based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the AC Onsite Power System is as follows:

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component (PBNP GDC 39).

As described in FSAR Chapter 8, Introduction of the Electrical Distribution Systems, independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

Additional information is provided in LR Section 2.3.5, Station Blackout.

In addition to the evaluations described in the FSAR, the AC onsite power system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, the AC onsite power-system was determined to be within the scope of the license renewal and components subject to age management review are evaluated on a plant-wide basis as commodities, where the generic commodity groups are described in SER Section 2.5 and age management is described in SER Section 3.6.

2.3.3.2 Technical Evaluation

Introduction

The AC onsite power system and its components are discussed in FSAR Section 8.0, Introduction of the Electrical Distribution Systems. The AC onsite power system consists of unit auxiliary transformers 1/2-X02, low voltage station auxiliary transformers 1/2-X04, the 19 kV, 13.8 kV (including gas turbine, G05), 4160 V, 480 V, 120 V systems (including rectifier/inverters and regulator transformer), emergency diesel generators, associated buses, cables, non-segregated phase bus, electrical penetrations (where applicable), circuit breakers and protection relays. In addition, the main generators 1/2-TG01, new generator circuit breakers, and isolated phase bus (IPB) duct are included in the AC onsite power system evaluations.

The function of the three-phase, three-winding unit auxiliary transformers (UAT) 1/2-X02 is to provide power from the main generator output stepped down from 19 kV to 4.16 kV to supply the onsite AC electrical distribution system normal loads for power operation during normal, abnormal, unit startup, unit shutdown and after reactor trip conditions.

The function of the 19 kV system is to distribute the energy developed by the unit's main generators 1/2-TG01 to main transformers 1/2-X01 and unit auxiliary transformers 1/2-X02.

The function of the low voltage station auxiliary transformers (LVSAT) 1/2-X04 is to step down voltage from the 13.8 kV system to 4.16 kV to provide power to the safety and non-safety related plant auxiliary system.

The function of the 13.8 kV system is to distribute power from the offsite power supply or gas turbine to the plant auxiliary system via the low voltage station auxiliary transformers and safe shutdown buses via step-down transformers.

The function of the 4160 V system is to supply power to non-safety related and safety-related loads.

The function of the 480 V system is to step down the 13.8 kV and 4160 V4160 V to 480 V to supply non-safety related and safety-related buses, and through step-down transformers to rectifier/inverters to supply 120 V AC instrumentation and direct current (DC) controls. The normal supply to non-safety related buses 1/2-B01 and 1/2-B02 is from buses 1/2-A01 and 1/2-A02, respectively, which are powered from UATs 1/2-X02. Power for safety-related buses 1/2-B03 and 1/2-B04 are from buses 1/2-A05 and 1/2-A06, respectively, which are connected to the low voltage station auxiliary transformers 1/2-X04.

The function of the 120 V system is to provide power to the vital and non-vital controls and instrumentation loads.

The function of each emergency diesel generator is to provide emergency power to one train of 4160 V safety-related buses in order to safely shut down one unit under accident conditions with sufficient power capacity to safely shut down the unaffected unit following a loss of offsite AC power.

The function of the main generators 1/2-TG01 is to provide a means of converting the mechanical energy of the main turbine into a supply of regulated and usable electricity. The generator output is delivered at 19 kV to the main transformers 1/2-X01 and unit auxiliary transformers 1/2-X02 through the isolated phase bus duct.

The function of the isolated phase bus duct is to conduct electrical power from the main generators to the main transformers and unit auxiliary transformers.

New 19 kV generator circuit breakers are being installed to synchronize the main generators to the offsite system and improve the capability of the onsite electrical distribution system to function at EPU. The breakers operate automatically on generator trips and can be manually operated from the control room. This modification eliminates the fast bus transfer of non-safeguards 4160 V loads to the low voltage station auxiliary transformers 1/2X-04 on a unit trip. On such a trip, these loads will remain energized from the unit auxiliary transformers 1/2X-02. The tap settings on the 1/2X-04 LVSATs will then be changed to optimize voltage to the safeguards 4160 V buses.

Description of Analysis and Evaluations

The AC onsite power system and its components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation is based on the system's required design functions and attributes, and upon comparison between the existing equipment ratings and anticipated operating requirements at EPU conditions. The EPU conditions require that the equipment operate at service conditions different than the currently evaluated operating conditions. To determine the impact of EPU operation on the AC onsite power system, a baseline for bus loading was developed to represent the existing plant loading conditions. New load flow/short circuit current analyses were performed that include load changes as a result of EPU conditions. The results of these analyses are used to ensure that the system and equipment are capable of performing their intended functions and form the bases for the AC onsite power system evaluations.

Results

<u>Unit Auxiliary Transformer (UAT)</u>

The unit auxiliary transformers 1/2-X02 are discussed in FSAR Section 8.3.1, 19K VAC Electrical Distribution System, Design Basis, FSAR Section 8.3.2, 19K VAC Electrical Distribution System, System Description and Operation, and FSAR Section 8.4.2, 4.16K VAC Electrical Distribution System, System Description and Operation. The calculated worst-case transformer load at current and EPU conditions are shown in Table 2.3.3-1, Unit Auxiliary Transformers Input Load. The evaluation confirms that the existing unit auxiliary transformers 1/2-X02 design rating of 28/37.3 MVA at 55°C oil-immersed, self cooled/forced-air cooled (OA/FA) is adequate to support each unit at EPU.

<u>Low Voltage Station Auxiliary Transformers (LVSAT)</u>

The low voltage station auxiliary transformers 1/2-X04 are discussed in FSAR Section 8.2.2, 13.8K VAC Electrical Distribution System - System Description and Operation, Section 8.4.2, 4.16K VAC Electrical Distribution System - System Description and Operation and Section 8.1.2, 345K VAC Electrical Distribution System - System Description and Operation. The new main generator circuit breaker and 4.16 kV bus transfer scheme modifications result in a decrease of the LVSAT loading due to the continued powering of the non-safeguards 4.16 kV buses 1/2-A01 and 1/2-A02 from unit auxiliary transformers 1/2-X02. The LVSAT load at current and EPU conditions are shown in Table 2.3.3-2, Low Voltage Station Auxiliary Transformers Input Load. The evaluation confirms that the existing LVSATs 1/2-X04 design rating of 28/37.3 MVA at 55°C OA/FA is adequate to support each unit at EPU.

13.8 kV System

The 13.8 kV system is discussed in FSAR Section 8.2, 13.8 kV Electrical Distribution System. The new main generator circuit breaker additions and 4.16 kV bus transfer scheme modifications allow the existing 345 kV breakers to remain closed to supply auxiliary power to the plant in the event of a generator trip. The non-safety related 13.8 kV system experiences improved voltage levels, lower short circuit currents and lower equipment loading. Table 2.3.3-3, 13.8 kV Switchgear Continuous Current, and Table 2.3.3-4, Short Circuit Current at 13.8 kV Switchgear Buses and Breakers, demonstrate the adequacy of the 13.8 kV system at EPU conditions based on the following:

Switchgear Buses, Circuit Breakers, Feeder Cables and Bus Ducts:

- The calculated worst case steady-state continuous currents for 13.8 kV switchgear buses, circuit breakers and bus ducts during operation at EPU conditions are less than the equipment design ratings, as indicated in Table 2.3.3-3. Evaluation of the worst case steady state continuous load current for the 13.8 kV switchgear cables during operation at EPU conditions determined that the load current at EPU is less than the existing worst case steady state continuous load current. Therefore, the EPU loading requirements of switchgear buses, circuit breakers, feeder cables and bus ducts are bounded by equipment design ratings.
- The calculated worst case short circuit currents (interrupting and momentary) at the 13.8 kV switchgear buses and circuit breakers during operation at EPU conditions are less than the equipment short circuit ratings, as indicated in Table 2.3.3-4. Therefore, the EPU short circuit requirements of switchgear buses and breakers are bounded by equipment design ratings.

System Voltage Levels:

There are no loads directly connected to the 13.8 kV system that have specific voltage requirements. However, there are voltage requirements for operating the 13.8 kV gas turbine generator G-05, which are not impacted by EPU.

Gas Turbine Generator Load Requirements:

There are no Gas Turbine Generator load changes as a result of EPU. Refer to LR Section 2.3.5, Station Blackout, for additional information.

4160 V System

The 4160 V system is discussed in FSAR Section 8.4, 4.16K VAC Electrical Distribution System. The new main generator circuit breaker additions and the 4160 V fast bus transfer scheme modifications improve the performance of the safety-related 4160 V and 480 V systems. The safety-related system experiences improved voltage levels and lower short circuit currents under these modifications.

New 19 kV generator circuit breakers are being installed to synchronize the main generators to the offsite system and improve the capability of the onsite electrical distribution system to function at EPU. The breakers operate automatically on generator trips and can be manually operated from the control room. This modification eliminates the fast bus transfer of non-safeguards 4160 V loads to the low voltage station auxiliary transformers 1/2X-04 on a Unit trip. On such a trip, these loads will remain energized from the unit auxiliary transformers 1/2X-02. The tap settings on the 1/2X-04 LVSATs will then be changed to optimize voltage to the safeguards 4160 V buses.

Switchgear Buses, Circuit Breakers Bus Ducts:

- The calculated worst case steady state continuous currents for 4160 V switchgear buses, circuit breakers and bus ducts, during operation at EPU conditions, are less than the equipment design ratings, as indicated in Table 2.3.3-5.
- The condensate pump, steam generator feedwater pump, heater drain pump, and reactor coolant pump (RCP) motors are affected by station operation at EPU conditions. The calculated worst case full load current for each affected motor during operation at EPU conditions is less than the feeder circuit breaker and cable design ratings, as indicated in Table 2.3.3-9. Based on the RCP protection curves in the existing 4160 V system protection analysis, the anticipated increase in load current for the RCP motors under hot and cold loop conditions does not impact the electrical penetration thermal rating. Therefore, the EPU loading requirements of motor feeder breakers, electrical penetrations and cables are bounded by equipment design ratings.
- The calculated worst case short circuit currents (interrupting and momentary) for the 4160 V switchgear buses and circuit breakers during operation at EPU conditions are less than the equipment short circuit ratings, as indicated in Table 2.3.3-6.

System Voltage Levels:

- During operation at EPU conditions, the calculated steady state voltages at the terminals of the affected non safety 4 kV running motors are within the allowable voltages, as indicated in Table 2.3.3-7. Therefore, the EPU voltage level requirements of the running motors are bounded by equipment design ratings and will be confirmed by the modification design process.
- The results of the evaluation demonstrate that there are no adverse effects on the 4160 V system voltages, and therefore the degraded voltage relay settings are not affected by EPU.
- The loss of voltage (LOV) relay settings for the safety-related 4160 V buses and non-safety related 4160 V buses have been evaluated. It has been determined that the LOV relay time delays are not adequate to ride through a grid disturbance at EPU conditions. The LOV relay time delay changes will be implemented as part of the plant modification process. Technical Specification 3.3.4 will be revised to incorporate new LOV time delay allowable values for safety-related buses.

Motor Load Requirements:

The condensate pump, steam generator main feedwater pump, heater drain pump, and reactor coolant pump motors are affected by station operation at EPU conditions. The auxiliary feedwater (AFW) system is being redesigned to support EPU operation (see LR Section 2.5.4.5, Auxiliary Feedwater), and includes the installation of two new higher capacity motor-driven AFW pumps in the primary auxiliary building. The new 4 kV AFW pump motors have been evaluated and determined to be acceptable under EPU conditions (see LR Section 2.5.4.5, Auxiliary Feedwater). The two existing 460V motor-driven pumps are being redesignated as standby steam generator pumps (SSGs) and each will be controlled manually for startup, shutdown and certain non-accident events.

The evaluation of the reactor coolant pump motors for operation during hot-loop and cold-loop EPU conditions are provided in LR Section 2.2.2.6, Reactor Coolant Pumps and Supports. The evaluation determined that the new motor service requirements are within the 6000 HP nameplate rating for hot-loop conditions. Motor evaluation under bounding cold-loop conditions has determined that the motors are acceptable including the motor thrust bearings. The Reactor Coolant Pump (RCP) motors are within the horsepower (HP) ratings as shown on Table 2.3.3-8, Motor BHP Load.

The condensate pump and main feedwater pump motor BHP increase at EPU is beyond the capability of the existing motors. Therefore, they are being replaced with larger motors capable of supporting the BHP requirements at EPU conditions. The evaluation of the condensate and feedwater systems is discussed in LR Section 2.5.5.4, Condensate and Feedwater. The heater drain pump BHP decreases at EPU. During operation at EPU conditions, the BHP for these affected motors are within their motor nameplate rating, as indicated in Table 2.3.3-8. Therefore, the EPU load requirements of these motors are bounded by the design ratings of the existing or replacement motors.

Motors, Electrical Penetrations and Cables Protection:

The protective relay settings for the condensate pump and main feedwater pump motors will be revised to protect the replacement motors and provide coordination. The heater drain pump motor BHP has decreased under EPU conditions and the protection settings for this motor are not impacted. The RCP motor overcurrent protection settings are impacted by cold-loop conditions and will be revised to prevent nuisance alarming during these conditions while providing adequate protection for the motors, electrical penetrations and cables. The necessary protective relay setting changes will be determined and implemented as part of the plant modification process.

480 V System

The 480 V system is discussed in FSAR Section 8.5, 480 Volt AC Electrical Distribution System. The main generator circuit breaker additions and 4.16 kV bus transfer scheme modifications improve the performance of the safety-related 480 V system. The safety-related system experiences improved voltage levels and lower short circuit currents under these modifications. The impact on the 480 V system will be confirmed for all additional EPU modifications by the modification process.

4160 V - 480 V Station Service Transformers:

The load changes downstream of the station service transformers required for EPU consist of Isolated Phase Bus (IPB) duct cooling systems and new main transformers cooling systems. The station service transformer EPU loads as modeled in the AC load flow/short circuit analysis do not exceed the design ratings of these transformers. Therefore, the EPU load requirements of these transformers are bounded by the equipment design ratings.

480 V Load Center Buses and Breakers:

- The load changes on the 480 V system are due to the IPB duct cooling system and new main transformers cooling systems which affects the non safety 480 V motor control center buses. The load changes in the AC load flow/short circuit analysis will be confirmed that they do not adversely impact the loading requirements upstream on 480 V load center buses and breakers under EPU conditions and the load center buses and breakers will remain bounded by equipment design ratings. This will be confirmed as part of the modification design process.
- The short circuit currents (interrupting and momentary) at affected 480 V load center buses and circuit breakers during operation at EPU conditionswill be confirmed that they are within the equipment short circuit ratings. The EPU short circuit requirements of load center buses and breakers will reamin within the equipment design ratings. This will be confirmed as part of the modification process.

480 V Motor Control Center Buses and Breakers:

- The load changes on the 480 V system are due to IPB duct cooling system and new main transformers cooling systems. The loads in the AC load flow/short circuit analysis will be confirmed that they do not adversely impact the loading requirements on the affected 480 V motor control center (MCC) buses and breakers under EPU conditions. The continuous current requirements for motor control center buses and circuit breakers at EPU conditions will be confirmed by AC load flow/short circuit analysis. This will be confirmed as part of the modification design process.
- The short circuit currents (interrupting and momentary) at affected 480 V motor control center buses and circuit breakers during operation at EPU conditions will be confirmed that they remain within the equipment short circuit ratings. The EPU short circuit requirements of motor control center buses and breakers will remain within the equipment design ratings in the AC load flow/short circuit analysis. This will be confirmed as part of the modification process.

System Voltage Levels:

The calculated steady state voltages at the terminals of the affected non safety 480 V MCC motors during operation at EPU conditions will be confirmed that they remain within the allowable voltages. The EPU voltage level requirements of MCC motors will be confirmed that they remain bounded by equipment design ratings, and the EPU voltage levels on the load center loads are bounded by the voltage requirements used in the AC load flow/short circuit analysis. This will be confirmed as part of the modification process.

The LOV relay setting for the safety-related 480 V buses have been evaluated. It has been determined that the LOV relay time delays are not adequate to ride through a grid disturbance at EPU conditions. The LOV relay time delay changes will be implemented as part of the plant modification process. Technical Specification 3.3.4 will be revised to incorporate the new LOV time delay allowable values for safety-related 480 V buses.

Motor Load Requirements:

The isolated phase bus duct cooling and main transformer replacement modifications require 480 V power supplies from existing motor control centers to these cooling system loads. The equipment rated load on the existing isolated phase bus duct cooling systems will increase from 7.5 HP to 25 HP fan motors, while the equipment rated load on the replacement main transformer cooling systems will decrease. Power supply requirements have been analyzed and there is no adverse impact on the 480 V system from these modifications, as determined in the AC load flow/short circuit analysis. Modifications to the isolated phase bus duct and main transformers will be implemented prior to EPU operation. This will be confirmed as part of the modification design process.

120 V AC System

The 120 V (low voltage) AC system is discussed in FSAR Section 8.6, 120 VAC Vital Instrument Power. Evaluation of the low voltage AC system at EPU conditions determined that there are minimal changes to the 120 V AC vital instrument power system required to support EPU conditions. The Auxiliary Feedwater System changes are identified in LR Section 2.5.4.5, Auxiliary Feedwater.

However, there are modifications required due to EPU conditions in Units 1 and 2 that affect the non safety-related 120 V AC instrument power system. These modifications are as follows:

- Addition of main feedwater pump minimum flow recirculation controls
- Addition of heater drain tank level/recirculation controls
- Replacement of feedwater heater controls – HP (4th and 5th Pt)
- Replacement of feedwater heater controls – LP (1st, 2nd, 3rd Pt)

The new load additions from these modifications are expected to be minor and the effect on the non safety-related 120 V AC instrument power system is expected to be small. Therefore, the voltage levels and short circuit current requirements for the 120 V AC instrument system equipment will not be adversely affected by EPU conditions, and equipment ratings are expected to remain bounded by the existing equipment design ratings. The new load additions will be confirmed and their effects on the system will be verified as part of the plant modification process.

Emergency Diesel Generators

The emergency diesel generators are discussed in FSAR Section 8.8, Diesel Generator (DG) System. The 2000-hour rating for the Train A EDGs is 2850 kW and the 2000 hour rating for the Train B EDGs is 2848 kW. Additional ratings for the Train A EDGs include 2963 kW for

200 hours and additional ratings for the Train B EDGs include 2951 kW for 200-hours. Review of the loads for operation at EPU conditions indicates that there are no load additions required to the emergency diesel generators except for the addition of the new AFW pump motors and the AST control room modification to automatically start the control room emergency fans.

In support of operation at EPU conditions, the AFW system is being redesigned, and includes the addition of two new 400 V AFW pump motors (refer to LR Section 2.5.4.5, Auxiliary Feedwater). These new motors have been evaluated for EPU, and the evaluation has demonstrated that an increase in the EDG loading is within the EDG 200-hour rating for Train A and the 200-hour rating for Train B. After 24 hours, the EDG loading is less than the 2000 hour rating. No EDG modifications are required. The existing 460V AFW pumps are retained for manual operation during startup, shutdown, certain non-accident events. This decision to keep the existing 460V AFW pumps does not adversely affect the worst case load on the EDGs since the evaluation is performed with the 4000V AFW pump motors and operating procedures and interlocks will be implemented to preclude running both 4000V and 460V pumps from one train at the same time unless adequate margin is available on the EDG.

New charging pump motors and Variable Frequency Drive (VFD) modifications have been evaluated for EPU. The evaluation is based on VFDs and motors for 1P-2B and 2P-2C being currently installed. The evaluation indicates that VFD and motor for 1P-2C needs to be installed prior to EPU to ensure Train B EDGs will continue to operate within their design rating (commitment 7 in Attachment 4). Three other VFDs and motors associated with 1P-2A, 2P-2A, and 2P-2B with or without the VFD modifications have been evaluated to demostrate that Train A and B EDGs will continue to operate within design ratings after installation. Alternative Source Term modifications are described in LAR 241 (ML083450683). The evaluation determined that Train A EDGs will continue to operate within the 2000 hour rating of 2850 kW and the Train B EDGs will continue to operate within the 200-hour rating of 2951 kW for up to 24 hours and then remain within the 2000 hour rating of 2848 kW.

Refer to LR Section 2.5.7.1, Emergency Diesel Engine Fuel Oil Storage and Transfer System, for the Emergency Diesel Engine Fuel Oil Storage and Transfer System evaluation.

Main Generator

The main generator for each unit is discussed in FSAR Section 8.3.1, 19K VAC Electrical Distribution System, Design Basis. The existing main generator rating for each unit is 582 MVA, 19 kV, 60 HZ, 0.90 power factor, 1800 rpm at 60 psig hydrogen pressure. The main generator has been evaluated at EPU conditions. To support unit operation at EPU conditions, a generator study was performed. As a result, it was determined that a generator rewind is required.

It was initially planned to rewind the generator to a rating of 713 MVA at a 0.90 power factor and 75 psig hydrogen pressure. Currently for EPU, it is planned to rewind the generator to a rating of 684 MVA at a 0.94 power factor and 75 psig hydrogen pressure. Either rewind is adequate to support operation at EPU including machine lagging reactive power requirements, as indicated in Table 2.3.3-10, Units 1 and 2 Main Generator Output Capability. The generator rating will be confirmed and the rewind implemented as part of the design modification process. Refer to LR Section 2.5.1.2.2, Turbine Generator, for a discussion on turbine-generator.

Generator Breaker

The main generator circuit breaker addition will be implemented prior to EPU and was included in the EPU evaluations. The main generator output breaker evaluation at EPU conditions was performed utilizing the initially planned rating of the main generator, 713 MVA (see Main Generator section), which is greater than the currently planned rating of the main generator, 684 MVA. However, evaluation of the generator breaker at the 713 MVA rating provides conservative results, which bound the results from an evaluation using the 684 MVA rating. Evaluation of the generator circuit breakers was based upon a comparison of the maximum anticipated full-load current at EPU and the design ratings of the generator circuit breaker with the generator operating at 95% of rated voltage. The evaluation demonstrates that the continuous current rating of the generator circuit breakers, which is 25 kA, envelops the worst case EPU loading of 22.8 kA of the main generator. The evaluation demonstrated that the peak (420 kA, peak) and interrupting (210 kA, rms symmetrical) short circuit current ratings of the generator circuit breakers envelope maximum peak and adjusted interrupting fault duties of 317 kA and 116 kA, respectively. The rating of the generator circuit breaker is within the calculated continuous load and short circuit current under EPU conditions and is therefore acceptable for EPU.

Isolated Phase Bus Duct

The isolated phase bus duct is discussed in FSAR Section 8.3.1, 19 K VAC Electrical Distribution System, Design Basis. The existing isolated phase bus duct main bus continuous current design rating is 20 kA forced cooled. The isolated phase bus duct evaluation at EPU conditions was performed utilizing the initially planned rating of the main generator, 713 MVA (see Main Generator section), which is greater than the currently planned main generator rating, 684 MVA. However, evaluation of the isolated phase bus duct at the 713 MVA rating provides conservative results, which bound the results from an evaluation utilizing the 684 MVA rating.

As a result of the EPU evaluations, the isolated phase bus duct main bus will be upgraded to 23.0 kA, which bounds unit operations at worst-case EPU loading conditions, as indicated in Table 2.3.3-11, Units 1 and 2 Isolated Phase Bus Main Bus Continuous Current at EPU. The change needed to accomplish the upgrade to 23.0 kA is to increase the main bus forced cooled air flow and increase the main transformer tap (delta) bus rating to 13.50 kA (anticipated to remain self cooled). The main transformer tap bus will have increased loading that will require modification. Required modifications to the isolated phase bus will be implemented as part of the design modification process prior to operation at EPU conditions. Additional insulators on the auxiliary tap bus will be added to increase the short circuit rating. The evaluation of the isolated phase bus tap bus confirms that the continuous current rating envelops the worst-case bus loading at EPU conditions. Also, the evaluation indicates that the isolated phase main and tap bus short circuit design ratings envelop the available short circuit current levels at EPU conditions, as indicated in Table 2.3.3-12, Unit 1 and 2 Maximum Calculated Fault Current on Isolated Phase Bus Duct at EPU.

Protection

The main transformer protection is discussed in FSAR Section 8.3, 19K VAC Electrical Distribution System. The low voltage station auxiliary transformer protection is discussed in

FSAR Section 8.2.2, System Distribution System and FSAR Section 8.4.2, 4.16K VAC Electrical Distribution System, System Description and Operation. Main generator, main transformer and unit auxiliary transformer protection are discussed in the FSAR Table 8.3.1. The LVSAT protection has been evaluated, and it has been determined that no changes are required.

The present protection scheme for the main generators and main transformers is to operate 345 kV switchyard breakers to isolate a 19 kV or 345 kV system fault. Power to the plant auxiliaries is then supplied by the low voltage station auxiliary transformers. With the addition of the new generator circuit breakers, the generator protection will trip the new generator circuit breaker without affecting the switchyard breakers. Also a new overcurrent protection relay is being provided for the main transformer. This will allow the unit auxiliary transformers to remain energized from the switchyard and to continue to supply plant auxiliary loads. The main and unit auxiliary transformer protection will isolate transformer faults by tripping the switchyard breakers. The new generator output circuit breaker protection scheme requires changes to the main generator, main transformer and UAT protection settings. These changes will be addressed as part of the plant modification process for the main generators.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The AC Onsite Power System was determined to be within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839, Section 2.5, Scoping and Screening Results, Electrical and Instrumentation and Controls. Aging Management Programs used to manage the aging effects associated with long-lived electrical components are addressed in NUREG-1839, Section 3.6, Aging Management of Electrical Components. The EPU modifications for the AC Onsite Power System add new components but do not introduce any new functions that would change the license renewal system evaluation boundaries. The changes associated with operating the AC Onsite Power System at EPU conditions do not add any new or previously unevaluated materials. Thus, no new aging effects requiring management are identified as a result of EPU. Aging effects and the programs used to manage the aging effects for the AC Onsite Power System components will be addressed in the plant modification process.

2.3.3.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the AC onsite power system and concludes that it has adequately accounted for the effects of the proposed EPU on the system's functional design following implementation of the proposed modifications. Revisions Technical Specification 3.3.4 are required to implement the revised LOV relay time delay changes. PBNP further concludes that the AC onsite power system will continue to meet the requirements of PBNP GDC 39 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the AC onsite power system.

2.3.3.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.3.3-1
Unit Auxiliary Transformers Input Load

Input Load	H-Winding Load MW	H-Winding Load MVAR	H-Winding Load MVA	H-Winding Design Rating (MVA)	Notes
Unit 1 Unit Auxiliary Transformer 1-X02 Input Load					
Existing	21.700	11.194	24.417	28/37.3 @ 55°C (OA/FA)	1
EPU	25.629	13.260	28.856		2
Increment	3.929	2.066	4.439		3
Total	25.629	13.260	28.856	37.3 @ 55°C (FA)	
Unit 2 Unit Auxiliary Transformer 2-X02 Input Load					
Existing	21.862	11.148	24.540	28/37.3 @ 55°C (OA/FA)	1
EPU	25.939	13.859	29.409		2
Increment	4.077	2.711	4.896		3
Total	25.939	13.859	29.409	37.3 @ 55°C (FA)	

Notes:

1. Existing loading is derived from load flow analysis. Although the maximum FWP motor load is 5050 BHP (see Table 2.3.3-8), the existing loading is based on operating the FWP motors at 4000 BHP, which is evaluating post unit trip. These values represent the present calculated loading on the transformer prior to EPU.
2. EPU loading is derived from uprate load flow analysis. These values represent the total calculated loading on the transformer after EPU.
3. Increment loading is the difference between the existing loading and EPU loading. These values represent the change in loading on the transformer as a result of EPU. This increment loading is based on operating the feedwater pump motors at 4000 BHP, but it would decrease if the feedwater pump motors were operated at maximum load of 5050 BHP
(See Note 1).

Table 2.3.3-2
Low Voltage Station Auxiliary Transformers Input Load

Input Load	H-Winding Load			H-Winding Design Rating (MVA)	Notes
	MW	MVAR	MVA		
Unit 1 Low Voltage Station Auxiliary Transformers 1-X04 Input Load					
Existing	25.257	13.634	28.702	28/37.3 @ 55°C (OA/FA)	1
EPU	10.769	5.653	12.163		2
Increment	-14.488	-7.981	-16.541		3
Total	10.769	5.653	12.163	37.3 @ 55°C (FA)	
Unit 2 Low Voltage Station Auxiliary Transformers 2-X04 Input Load					
Existing	25.713	13.778	29.172	28/37.3 @ 55°C (OA/FA)	1
EPU	11.023	5.739	12.427		2
Increment	-14.690	-8.039	-16.746		3
Total	11.023	5.739	12.427	37.3 @ 55°C (FA)	

Notes:

1. Existing load is derived from load flow analysis.
2. EPU loading is derived from uprate load flow analysis. These values represent the total calculated loading on the transformer after EPU.
3. Increment load is the difference between the existing and EPU load. These values represent the change in loading on the transformer as a result of EPU.

Table 2.3.3-3
13.8 kV Switchgear Continuous Current

Bus	Maximum Existing Load (Amps)	Maximum EPU Load (Amps)	Current Rating (Amps)	Notes
H01	413.2	287.4	2000	1, 2
H02	1690.1	663.9	2000	1, 2
H03	1712.1	664.5	2000	1, 2
H05	1690.1	674.8	2000	1, 2
H06	1712.1	664.5	2000	1, 2
1H04	1289.9	546.2	2000	1, 2
2H04	1308.6	555.8	2000	1, 2

Notes:

1. The continuous switchgear current for existing and EPU conditions are taken from worst-case load flow/short circuit analysis.
2. Switchgear buses, circuit breakers, and bus ducts have the same rating of 2000 Amps.

Table 2.3.3-4
Short Circuit Current at 13.8 kV Switchgear Buses and Breakers

Bus	Interrupting, symmetrical (kA) (Note 1,2)			Momentary, Asym. (kA) (Note 1,2)			
	Max. Adj. Existing Duty	Max. Adj. EPU Duty	Circuit Breaker Rating	Maximum Existing Duty	Maximum EPU Duty	Circuit Breaker Rating	Bus Rating
H01	25.010	20.962	36	39.964	32.052	58	40
H02	25.002	20.905	36	39.978	32.035	58	40
H03	20.894	20.694	36	39.945	32.058	58	40
H05	16.152	16.258	18	40.116	32.242	37	60
H06	16.359	16.360	18	40.108	32.376	37	60
1H04	N/A	N/A	N/A	39.734	31.760	N/A	60
2H04	N/A	N/A	N/A	39.662	31.722	N/A	60

Notes:

1. The calculated short circuit currents for existing and EPU conditions are taken from worst-case short circuit current analysis.
2. "N/A" means not applicable because buses 1H04 and 2H04 do not contain circuit breakers.

Table 2.3.3-5
4160 V Switchgear Bus Continuous Current

Bus	Maximum Existing Load (Amps)	Maximum EPU Load (Amps)	Current Rating (Amps)	Notes
1-A01	1791.4	2041.3	3000	1, 2
1-A02	1729.1	1963.3	3000	1, 2
1-A03	2077.9	818.3	3000	1, 2
1-A04	1987.2	948.4	3000	1, 2
1-A05	427.4	427.5	3000	1, 3
1-A06	382.6	383.2	2000	1, 4
2-A01	1791.7	2059.2	3000	1, 2
2-A02	1742.7	2022.9	3000	1, 2
2-A03	1981.1	789.4	3000	1, 2
2-A04	2143.0	1008.3	3000	1, 2
2-A05	354.4	354.3	1200	1, 5
2-A06	454.4	454.3	2000	1, 4

Notes:

1. The calculated continuous current values for the switchgear are obtained from worst-case existing and EPU load flow/short circuit analysis.
2. Switchgear buses, incoming circuit breakers, non-segregated phase bus ducts and tie circuit breakers ratings have the same rating of 3000 Amps.
3. Switchgear 1-A05 has a bus rating of 3000 Amps and circuit breaker rating of 1200 amps.
4. Switchgear 1/2-A06 has a bus rating of 2000 Amps and circuit breaker rating of 1200 amps.
5. Switchgear 2-A05 has a bus and circuit breaker rating of 1200 amps.
6. Subsequent to the analysis for this table, the AFW upgrade design was revised to power the new Unit 1 MDAFW pump from 1A-06 rather than 1A-05 and power the new Unit 2 MDAFW pump from 2A-05 rather than 2A-06, as shown above. There is adequate load capability remaining on the 1A-06 and 2A-05 buses to handle the additional approximately 45 amps.

Table 2.3.3-6
4160 V Switchgear Bus and Circuit Breaker Short Circuit Current

Bus	Breaker Frame Size	Interrupting, sym. (kA) (Note 1)			Momentary, Asym. (kA) (Note 1)			
		Max. Adj. Existing Duty	Max. Adj. EPU Duty	Circuit Breaker Rating	Max. Existing Duty	Max. EPU Duty	Circuit Breaker Rating	Bus Rating
1-A01	3000 A	38.417	38.675	41	59.115	60.082	78	84
	1200 A	45.722	46.926	49.5	76.770	80.090	84.1	84
1-A02	3000 A	39.134	39.376	41	60.331	61.218	78	84
	1200 A	46.570	47.573	49.5	81.729	80.937	84.1	84
1-A03	3000 A	34.353	33.164	41	73.643	52.194	78	84
1-A04	3000 A	39.822	38.237	41	49.600	60.064	78	84
	1200 A	47.203	38.291	49.5	81.821	60.547	84.1	84
1-A05	1200 A	40.977	32.669	49.5	71.001	50.917	84.1	80
1-A06	1200 A	41.244	35.216	42.4	68.846	55.668	80	80
2-A01	3000 A	37.953	38.208	41	58.455	59.372	78	84
	1200 A	45.237	46.346	49.5	76.014	79.290	84.1	84
2-A02	3000 A	37.914	38.252	41	58.429	59.280	78	84
	1200 A	46.983	46.494	49.5	82.790	79.002	84.1	84
2-A03	3000 A	34.035	32.871	41	72.981	51.590	78	84
2-A04	3000 A	39.735	38.624	41	65.130	60.669	78	84
	1200 A	47.058	38.693	49.5	82.887	61.426	84.1	84
2-A05	1200 A	40.506	32.246	49.5	70.296	50.292	84.1	80
2-A06	1200 A	41.561	35.565	42.4	70.012	56.671	80	80

Note:

1. The calculated short circuit currents are obtained from worst-case existing and EPU load flow/short circuit current analysis.
2. Subsequent to the analysis for this table, the AFW upgrade design was revised to power the new Unit 1 MDAFW pump from 1A-06 rather than 1A-05 and power the new Unit 2 MDAFW pump from 2A-05 rather than 2A-06, as shown above. There is adequate load capability remaining on the 1A-06 and 2A-05 buses to handle the additional approximately 45 amps. There is adequate fault current capability on the 1A-06 and 2A-05 buses to handle the additional 0.24 kA fault current (0.41 kA asymmetrical).

Table 2.3.3-7
Comparison of Running Motor Terminal Steady State Voltage

Bus	Motor	Rated Voltage (V)	Minimum Voltage (Note 1,2) (% of rated Voltage)			Maximum Voltage (Note 1) (% of rated Voltage)		
			Existing Voltage	EPU Voltage	Allowable Voltage	Existing Voltage	EPU Voltage	Allowable Voltage
1-A01	1P-001A (RCP)	4000	97.80	101.09	90	108.82	107.16	110
	1P-028A (FWP)	4000	99.98	101.31		108.80	107.34	
	1P-025A (COP)	4000	99.95	101.28		108.98	107.32	
	1P-027A (HDP)	4000	100.01	101.37		109.00	107.35	
	1P-027 C (HDP)	4000	100.01	101.36		109.00	107.35	
1-A02	1P-001B (RCP)	4000	97.90	101.36		108.95	107.34	
	1P-028B (FWP)	4000	100.11	101.52		108.89	107.47	
	1P-025B (COP)	4000	100.07	101.47		109.05	107.44	
	1P-027B (HDP)	4000	100.12	101.55		109.07	107.47	
2-A01	2P-001A (RCP)	4000	97.50	100.66		108.81	106.82	
	2P-028A (FWP)	4000	100.18	100.90		108.78	107.01	
	2P-025A (COP)	4000	100.13	100.86		108.97	106.98	
	2P-027A (HDP)	4000	100.20	100.95		109.00	107.01	
	2P-027 C (HDP)	4000	100.20	100.95		109.00	107.02	

Table 2.3.3-7
Comparison of Running Motor Terminal Steady State Voltage

Bus	Motor	Rated Voltage (V)	Minimum Voltage (Note 1,2) (% of rated Voltage)			Maximum Voltage (Note 1) (% of rated Voltage)		
			Existing Voltage	EPU Voltage	Allowable Voltage	Existing Voltage	EPU Voltage	Allowable Voltage
2-A02	2P-001B (RCP)	4000	97.47	100.75	90	108.89	106.91	110
	2P-028B (FWP)	4000	100.11	100.91		108.84	107.04	
	2P-025B (COP)	4000	100.08	100.89		109.01	107.03	
	2P-027B (HDP)	4000	100.15	100.98		109.04	107.06	

Note:

1. The calculated steady state voltages are obtained from the existing and EPU load flow/short circuit analysis.
2. These minimum EPU motor voltages shown are a result of using a minimum main generator output design voltage of 100%. When adjusted for a minimum main generator output design voltage of 95%, the adjusted voltage satisfy the minimum allowable voltage criteria of 90%. For example, using the worst-case minimum voltage shown of 100.66% from RCP 2P-001A, the minimum adjusted voltage is 95.63% (100.66% x 0.95), which is above the minimum allowable voltage criteria of 90%. This will be confirmed as part of the modification process.

Table 2.3.3-8
Motor BHP Load

Motor	Maximum Existing BHP	Existing Rated HP	Maximum EPU BHP	EPU Rated HP	Notes
Reactor Coolant Pumps 1/2P-001A, B	5100(Hot) 6607 (Cold)	6000 (Hot) 7500 (Cold)	5657 (Hot) 7212 (Cold)	6000 (Hot) 7500 (Cold)	1
SG Feedwater Pumps 1/2P-028A, B	5050	5000	5890	6200	1
Condensate Pumps 1/2P-025A, B	1138	1250	1350	1500	1
Heater Drain Pumps 1/2P-027A, B, C	441	450	420	450	1

Note:

1. The pump motor BHP load is obtained from the existing and EPU load flow/short circuit analysis.

Table 2.3.3-9
Motor Breaker and Feeder Cable Steady State Continuous Current

Motor	Maximum Existing Load (A)	Maximum EPU Load (A)	Breaker Frame Size	Feeder Cable Current Rating (A)	Notes
Reactor Coolant Pumps					
1P-001A	655.3	716.1	1200 A	773.24	1 and 4
1P-001B	654.7	714.1	1200 A	773.24	1 and 4
2P-001A	657.4	726.5	1200 A	773.24	1 and 4
2P-001B	657.5	725.9	1200 A	773.24	1 and 4
Main Feedwater Pumps					
1P-028A	492.9	689.3	1200 A	850.78	1 and 4
1P-028B	492.3	687.9	1200 A	850.78	1 and 4
2P-028A	491.9	692.0	1200 A	850.78	1 and 3
2P-028B	485.9	691.9	1200 A	850.78	1 and 3
Condensate Pumps					
1P-025A	140.2	166.2	1200 A	284.47	1 and 4
1P-025B	140.0	165.9	1200 A	284.47	1 and 4
2P-025A	140.0	166.9	1200 A	284.47	1 and 3
2P-025B	140.0	166.8	1200 A	284.47	1 and 3
Heater Drain Pumps					
1P-027A	55.5	52.5	1200 A	N/A	1 and 2
1P-027B	55.4	52.4	1200 A	N/A	1 and 2
1P-027C	55.5	52.5	1200 A	N/A	1 and 2
2P-027A	55.4	52.7	1200 A	N/A	1 and 2
2P-027B	55.4	52.7	1200 A	N/A	1 and 2
2P-027C	55.4	52.7	1200 A	N/A	1 and 2

Notes:

1. The steady state continuous motor load current is obtained from the worst case existing and EPU load flow/short circuit analysis.
2. “N/A” means not applicable because Heater Drain Pumps EPU load decreases and cables are not impacted by EPU.
3. Unit 2 main feed pumps and condensate pump motor feeder cables have the same configuration and the same cable current rating as those from Unit 1.
4. The feeder cable current rating is calculated based on appropriate derating factors.

Table 2.3.3-10
Units 1 and 2 Main Generator Output Capability

Unit Operation	MW	MVAR	MVA	Volts (kV)	PF (%)	Notes
713 MVA Evaluation Rating						
Lagging (Exporting VARs)	641.6	310.74	712.9	19	90	1, 2
Leading (Importing VARs)	641.6	-245	686.8	19	93.4	1, 2
684 MVA Currently Planned Rating						
Lagging (Exporting VARs)	641.6	235	683.3	19	93.9	1, 2, 3
Leading (Importing VARs)	641.6	-220	678.3	19	94.6	1, 2, 3

Notes:

1. Main Generator capability is determined from the applicable preliminary uprate generator calculated capability curve at 641.6 MW.
2. $MVA = \sqrt{MW^2 + MVAR^2}$
3. $PF\% = 100 \times \frac{MW}{MVA}$

Table 2.3.3-11
Units 1 and 2 Isolated Phase Bus Main Bus Continuous Current at EPU

Unit Operation	Generator Output MW	Generator Output MVAR	Generator Output MVA	PF %	Min. Gen. Output Voltage p.u. of 19 kV	Max. IPB Main Bus Load kA	IPB Main Bus FC Current Rating kA	Notes
Lagging (Exporting VARs)	641.6	310.74	712.9	90	0.95	22.8	23.0	1, 2, 3
Leading (Importing VARs)	641.6	-245	686.8	93.4	0.95	21.9		1, 2, 3

Notes:

1. Main generator output from Table 2.3.3-10, above.
2. IPB Main Bus Load Current $kA = \frac{MVA}{19kV \times 0.95 \times \sqrt{3}}$
3. The current design rating of the isolated phase bus duct, main bus is 23.0 kA (forced cooled).

Table 2.3.3-12
Unit 1 and 2 Maximum Calculated Fault Current on Isolated Phase Bus Duct at EPU

IPB Segment	Maximum Asymmetrical Fault Current kA	Asymmetrical Fault Current Rating kA
Main Bus	282.9	316.112
UAT Tap Bus	433.439	464.515

2.3.4 DC Onsite Power System

2.3.4.1 Regulatory Evaluation

The direct current (DC) onsite power system includes the DC power sources and their distribution and auxiliary supporting systems that supply motive or control power to safety-related equipment. The PBNP review covered the information, analyses, and referenced documents for the DC onsite power system. The NRC's acceptance criteria for the DC onsite power system is based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 17 is as follows:

CRITERION: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (PBNP GDC 39)

As described in FSAR Section 8.7, 125 VDC Electrical Distribution System, the 125 VDC Electrical Distribution System (125V) provides a reliable source of power for safety and non-safety related loads of both PBNP units. The system includes six separate, independent DC distribution buses, each capable of being connected to a common "swing" bus. Four of the six buses and the swing buses are safety-related and shared between the units. The other two buses are non-safety related and each is dedicated to a single unit.

Additionally, in Generic Letter 91-06 (Reference 2), the NRC staff identified actions to be taken by the licensees related to Generic Issue A-30, Adequacy of Safety-Related DC Power Supplies. Wisconsin Electric Power Company (WEPCO) responded with detailed information (refer to Reference 3). The NRC action was completed upon its transmittal letter to WEPCO (Reference 4), indicating that WEPCO's response satisfied the reporting requirements of the generic letter.

In addition to the evaluations described in the FSAR, the DC onsite power system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- License Renewal Safety Evaluation Report for the Point Beach Nuclear Plant, Units 1 and 2 (NUREG-1839), dated December 2005 (Reference 1)

The above SER determined the DC onsite power system to be within the scope of the license renewal. Components subject to age management review are evaluated on a plant wide basis as commodities, with the generic commodity groups described in SER Section 2.5.

2.3.4.2 Technical Evaluation

Introduction

The 125V DC system is discussed in FSAR Section 8.7, 125 VDC Electrical Distribution System. The safety-related 125V DC system consists of four main distribution buses which supply power for control, emergency lighting, and the 120V AC vital instrument bus inverters. Each of the four main distribution buses is powered by a battery charger and is backed up by a station battery. The function of the battery chargers is to supply their respective DC loads, while maintaining the batteries at full charge. The battery chargers have been sized to recharge any of their respective partially discharged batteries within 24 hours while carrying normal loads. In addition to the four 125V DC safety-related main distribution buses there are two safety-related swing DC distribution buses which permit the connection of a swing battery and/or swing charger to one of the four main distribution buses. Also, there is a swing safety-related battery that provides back up to one of the swing buses and can be aligned to any one of the four main distribution buses to take the place of the normal battery. The 125V DC system provides the battery capacity to cope with Station Blackout and 10 CFR Appendix R conditions.

There are two non-safety related 125V DC distribution buses with associated battery chargers and batteries that provide power to non-safety related loads and are dedicated to Unit 1 and Unit 2 specifically. A swing battery and charger can provide power to either of these non-safety related distribution buses during maintenance.

Description of Analysis and Evaluations

The 125V DC power system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. The evaluation is based on the system's required design functions and attributes, and upon a comparison between the existing DC equipment ratings and the anticipated operating requirements at EPU conditions.

Results

The safety-related and non-safety related portions of the 125V DC systems were evaluated to determine potential impacts due to EPU.

There are six plant modifications that are planned for PBNP Units 1 and 2 that will affect the safety and non-safety related portions of 125V DC system.

1. Addition of safety-related feedwater system isolation valve operators. These valve operators require the addition of four new solenoids per plant.

2. Addition of a new non-safety related generator circuit breaker, which requires a source for 125V DC control power.

3. Replacement of the Main Transformers, which requires a 125V DC power source for the addition of new non-safety related transformer annunciator panels.

4. Replacement of the non-safety related steam generator feedwater pumps which reduce DC load by removing DC auxiliary lube oil pumps.

5. Change power sources for safety-related turbine driven and motor driven auxiliary feedwater system components including control circuitry.

6. Upgrade of the non-safety related feedwater regulating valves which utilize lower wattage DC solenoids than the existing design.

The load changes resulting from these modifications are small and the effect on the 125V DC system has been found to be acceptable. The design of these modifications are in process and the effect on EPU will be evaluated as part of the modification progess. This includes determining the impact on the licensing basis using the 10 CFR 50.59 screening and evaluation process.

Turbine/generator load changes are expected to be relatively small and add loads to the non-safety related DC system. These changes will be finalized in the plant modification process. There is no impact to the safety-related DC system from these changes.

The 125V DC power system continues to have the capacity and capability to perform its function because the load additions are small. The DC power system remains within equipment ratings while maintaining adequate margin for battery capacity. Separate and independent station battery systems are maintained to supply power to all safety loads in accordance with PBNP licensing basis with respect to PBNP GDC 39.

In addition, Station Blackout and 10 CFR 50 Appendix R program evaluations did not result in any 125V DC load changes, as discussed in LR Section 2.3.5, Station Blackout, and Section 2.5.1.4, Fire Protection.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the DC onsite power system is within the scope of license renewal. However, the changes associated with operating the DC system at EPU conditions do not add any new or previously unevaluated materials to the system or exceed the operating or environmental parameters previously evaluated for equipment included within the scope of the rule. No new aging effects requiring management are identified.

2.3.4.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the DC onsite power system and concludes that it has adequately accounted for the effects of the proposed EPU on the system's functional design. PBNP further concludes that the DC onsite power system will continue to function as designed and continue to meet the requirements of PBNP GDC 39 following implementation of the proposed EPU. Adequate physical and electrical separation exists, and the DC system has the capacity and capability to supply power to all safety loads and other required equipment at EPU conditions. Therefore, PBNP finds the proposed EPU acceptable with respect to the DC onsite power system.

2.3.4.4

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 NRC Generic Letter (GL 1991-06, Resolution of Generic Issue A-30, "Adequacy of Safety-Related DC Power Supplies," Pursuant to 10 CFR 50.54(f), April 29, 1991

3 WEPCO letter to NRC, Response to Generic Letter 91-06: Adequacy of Safety-Related DC Power Supplies, Point Beach Plant, Units 1 and 2

4 NRC Letter to WEPCO, Staff Review of Generic Letter 91-06, Resolution of Generic Issue A-30 'Adequacy of Safety-Related DC Power Supplies,' Pursuant to 10 CFR 50.54(f), dated June 1, 1993

2.3.5 Station Blackout

2.3.5.1 Regulatory Evaluation

Station Blackout (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 Loss of Offsite Power (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" (AACs). The PBNP 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.

Specific review criteria are contained in:

- Standard Review Plant (SRP) Sections 8.1
- Appendix B to SRP Section 8.2
- Other guidance provided in Matrix 3 of RS-001.

PBNP Current Licensing Basis

The adequacy of the PBNP design relative to conformance to 10 CFR 50.63, Loss of All Alternating Current Power, is addressed in FSAR Appendix A.1, Station Blackout (SBO).

As addressed in FSAR Appendix A.1, PBNP was evaluated against the requirements of the Station Blackout Rule, 10 CFR 50.63, using guidance from NUMARC 87-00, Revision 0 and Regulatory Guide 1.155. The NRC has not endorsed Revision 1 to NUMARC 87-00.The NRC has accepted specific supplements to NUMARC 87-00 Rev. 0, as described in Appendix K of NUMARC 87-00 Rev. 1.

A description of the methodology and coping duration is provided in FSAR Appendix A.1.1, Station Blackout Overview, and A.1.2, Station Blackout Duration Determination.

The station blackout rule requires that the following issues be addressed:

- Station blackout duration
- Condensate inventory for decay heat removal
- Class 1E battery capacity
- Compressed air
- Effects of loss of ventilation
- Containment Isolation
- Reactor coolant inventory
- Procedures and Training
- Quality assurance

- Technical Specifications
- Emergency Diesel Generator (EDG) reliability program.

These issues are addressed in FSAR Appendix A.1, Station Blackout.

FSAR Appendix A.1.5, Procedures and Training, describes the procedures and training associated with SBO. PBNP currently has Emergency Operating Procedures (EOPs) addressing the loss of all AC power, including:

- ECA 0.0, Loss of All AC Power
- ECA 0.1, Loss of All AC Power Recovery Without Safety Injection (SI) Required
- ECA 0.2, Loss of All AC Power Recovery With SI Required

ECA 0.0 directs operators to restore power to the safety-related buses by EDG restart, offsite power reconnection, gas turbine generator G-05 start or opposite unit safety-related bus crosstie. ECA 0.1 and 0.2 provides guidance for recovery from the station blackout condition once AC power has been restored. The SBO recovery guidelines were implemented prior to promulgation of the Station Blackout Rule, and thus additional operator training was not necessary. The NRC considered the procedures to be acceptable, and appropriate training is implemented for any emergency AC power source configuration change.

The Station Blackout topical area is driven by regulatory requirements which evolved subsequent to licensing of PBNP. Consequently, the primary source of design basis information for the Station Blackout topical area is correspondence to and from the NRC. This correspondence defines PBNP commitments and the degree of conformance with industry and NRC guidance relating to Station Blackout.

The Gas Turbine Generator and each Emergency Diesel Generator are fully capable Alternate AC (AAC) sources with sufficient capacity and capability to operate systems necessary for coping with the required SBO duration.

The present coping methodology uses the Gas Turbine Generator (GTG) G-05 or an Emergency Diesel Generator (EDG) from the non-blacked out unit as ACC sources. An EDG will start, accelerate to rated frequency and voltage, and can be connected to an EAC bus in either unit within ten minutes of SBO initiation. The GTG will be manually started, accelerate to rated frequency and voltage, and be available to power the safe shutdown loads within one hour of SBO initiation. The GTG has a target reliability goal of 0.95.

In addition to the evaluations described in the FSAR, station blackout coping equipment was addressed as part of License Renewal as documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, station blackout is discussed in Sections 1.4 ,Interim Staff Guidance, 2.1.2.1.1, Application of the Scoping Criteria in 10 CFR 54.4(a), 2.1.3.1, Scoping Methodology, 2.3.1.1, Class 1 Piping/Components System, 2.3.1.5, Steam Generators, 2.3.1.6, Non-Call 1 RCS Components System, 2.3.3.1, Chemical and Volume Control System, 2.3.3.2, Component Cooling Water System, 2.3.3.8, Emergency Power System, 2.3.3.10, Essential

Ventilation System, 2.3.3.15, Plant Air System, 2.3.4.1, Main and Auxiliary Steam System, 2.3.4.2, Feedwater and Condensate System, 2.3.4.3, Auxiliary Feedwater System, 2.4.4, Diesel Generator Building Structure, 2.4.8, Yard Structures, 2.4.12, 13.8 kV Switchgear Building Structure, 2.4.13, Fuel Oil Pumphouse Structure, and 2.4.14, Gas Turbine Building Structure.

2.3.5.2 Technical Evaluation

Introduction

An SBO involves the loss of offsite power, with a concurrent turbine trip, and unavailability of the onsite emergency AC power system. An SBO, however, does not involve the loss of AC power to buses fed by station batteries through inverters or by alternate AC sources, as depicted in NRC Regulatory Guide (RG) 1.155.

Historically, regulatory concern regarding SBO arose because of the accumulated experience regarding the reliability of AC power supplies. Many operating plants have experienced a total loss of offsite power. In almost all of these events, onsite emergency power supplies have been available to immediately supply power to vital safety equipment. In a few instances, one of the redundant onsite AC sources was unavailable. In some cases there has been a complete loss of AC power, but during these events AC power was restored in a short time without any serious consequences. In addition, there have been numerous instances when emergency diesel generators have failed to start and run in response to tests conducted at operating plants as stated in RG 1.155. The results of the Reactor Safety Study (WASH-1400) showed that, for one of the two plants evaluated, SBO was an important contributor to the total risk from nuclear power plant accidents. Although the total risk was found to be small, the relative importance of SBO events was established. This finding and accumulated diesel generator failure experience through the 1970s increased the concern about SBO.

As result of the concern regarding SBO, the NRC undertook several regulatory initiatives to address the issue including establishing Unresolved Safety Issue A-44 for SBO. The overall regulatory approach was to improve the capability to respond to an SBO and reduce their probability of occurrence. NRC Generic Letter (GL) 81-04 addressed improvements to operator training and development of procedures to specifically cope with an SBO. GL 84-15 addressed actions to maintain and improve emergency diesel generator reliability. On June 21, 1988, the NRC issued a final rule, which revised 10 CFR 50 to define SBO and added a new Section, 10 CFR 50.63, Loss of all alternating current power. In summary, the final rule required:

- Each nuclear plant to be able to withstand and recover from an SBO of a specified duration. 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 specified duration to be based on the redundancy of onsite emergency power sources, the reliability of onsite emergency power sources, the expected frequency of loss of offsite power, and the probable time required to restore offsite power; and,

- Licensees to submit information regarding a proposed blackout duration and identify procedure changes and modifications necessary to cope with a blackout of the specified duration, and schedule for their implementation.

NRC Regulatory Guide 1.155 (Reference 1) and NUMARC 87-00, Guidelines and Technical Bases for NUMARC Initiatives Addressing SBO at Light Water Reactors, provide guidance for implementation of the SBO rules.

As addressed in the FSAR Appendix A.1, Station Blackout, the SBO rule requires that specific issues be addressed. A description and evaluation of the impact of EPU on the following SBO issues is provided:

- SBO duration, including the Emergency Diesel Generator (EDG) reliability program.
- SBO Coping Analysis, which includes: Condensate inventory for decay heat removal; Safety-related battery capacity; Compressed air; Containment Isolation; Reactor coolant inventory and Effects of loss of ventilation (Containment Building; Instrument inverter rooms; Cable Spreading Room; Auxiliary Feedwater Pump Room; Control Room and Computer Room).
- Alternate AC Source
- Procedures and training,
- Quality assurance

SBO Duration Coping Time

The potential for long duration loss of off-site power (LOOP) events can have a significant impact on plant risk. Long duration LOOP events are typically associated with grid failures due to severe weather conditions or unique transmission system features. Shorter duration LOOP events tend to be associated with plant specific switchyard features. Per 10 CFR 50.63, the required coping duration shall be based on the following factors:

1. The redundancy of the emergency standby power system
2. The reliability of each of the emergency power sources
3. The expected frequency of a loss of offsite power
4. The probable time required to restore offsite power

Based on the above factors and the extremely severe weather group classification as discussed in FSAR Appendix A.1.1, Station Blackout Overview, through A.1.4, Alternate AC Source, the coping duration category for PBNP is four (4) hours. This is the time from a loss of all off-site power until restoration of off-site power. However, qualified on-site alternate AC sources (AAC) are available and capable of service within 10 minutes. Coping evaluations assume power is provided by only non-AC power sources for the first hour and restoration of on-site AC power at one hour. PBNP has designated two potential AAC sources: 1) an available EDG which can be started within 10 min, and 2) a Combustion Turbine, which can not be started within 10 min.

Since all the SBO coping duration determination factors and the availability of an onsite AAC are unaffected by EPU, these coping durations remains unchanged.

Condensate Inventory for Decay Heat Removal

During the first hour, water is supplied to the steam generators (SGs) for removal of decay heat by the Turbine-Driven Auxiliary Feedwater (TDAFW) pump, which takes suction from the condensate storage tanks (CST) (refer to LR Section 2.5.4.5, Auxiliary Feedwater). The Unit 1 and 2 CST required level per unit to support one hour of decay heat removal at the EPU is 15,410 gallons. This volume maintains approximately the same additional time margin for switchover of the Auxiliary Feedwater supply that was committed to as a result of the original PBNP SBO rule safety evaluation. The minimum required CST level at the uprate power based on NUMARC 87-00, Rev. 1 without the additional margin consideration is 14,000 gallons.

PBNP Technical Specification (TS) Section 3.7.6 currently requires a level of 13,000 gallons and must be revised to require a level of 15,410 gallons for each operating unit. Each CST has a capacity of 45,000 gallons, and is shared by both units. As such, a single CST has sufficient capacity to supply the required 15,410 gallons per unit.

After the first hour, when AC power is restored, the AFW pump suction is switched from the CST to Service Water. The Service Water system is maintained as the safety related source of water to the Auxiliary Feedwater system (TS 3.7.5) under EPU conditions.

Class 1E Battery Capacity

EPU does not require SBO-related equipment to be added or changed which would require additional DC power during an SBO event. There are no significant additional loads added to the safety-related battery during an SBO at EPU conditions. The DC system remains adequate for SBO operation as discussed in LR Section 2.3.4, DC Onsite Power System.

Compressed Air

EPU does not require SBO related equipment to be added or changed which would require compressed air during an SBO event. The TDAFW pump system used to provide water to the SGs during an SBO event is not being changed by EPU as discussed in LR Section 2.5.4.5, Auxiliary Feedwater. No safety-related air operated valves required to cope with an SBO event during the first hour, are being changed by EPU. Therefore, there are no requirements for additional compressed air during an SBO at EPU conditions. The new MFIV installed in the Feedwater system do not operate (fail as-is) during an SBO event, and therefore, use no addtional air.

Effects of Loss of Ventilation

Loss of ventilation affects the temperature in areas containing equipment required to mitigate an SBO event including the Containment Building; Instrument Inverter Rooms; Cable Spreading Room; Auxiliary Feedwater Pump Room; Control Room and Computer Room. Changes due to EPU result in negligible increases in room temperatures during an SBO from those previously evaluated. The room temperatures will remain below the maximum allowable temperatures during an SBO coping period and therefore the operability of SBO related equipment in these rooms is not affected by the loss of ventilation. Two motor driven (MD) AFW pumps are being added for EPU. Cooling requirements for the new pumps are evaluated as part of the AFW reconfiguration modifications as discussed in LR Section 2.5.4.5, Auxiliary Feedwater.

Containment Isolation

In accordance with FSAR Appendix A.1.3, Station Blackout Coping Analysis, the Containment Isolation valves were reviewed to verify that valves which must be capable of being closed or that must be operated under station blackout conditions can be positioned, with indication, independent of the blacked-out unit's safety-related power supplies.

The following isolation valve types are excluded as valves of concern:

1. Valves normally locked closed during operation
2. Valves that fail closed on a loss of power
3. Check valves
4. Valves in non-rad, closed loop systems not expected to be breached in an SBO (Except lines which communicate directly with the containment atmosphere)
5. Valves of less than 3-inch nominal diameter.

Based on these exclusion criteria, there are five penetrations for each PBNP unit for which indication and control would be lost during an SBO event. Four of the five penetrations are associated with motor-operated valves in the component cooling water system. Manual isolation capability for these four valves provides adequate Containment Isolation. The remaining penetration is associated with the chemical and Volume Control System, and includes an automatic air-operated valve inside containment. This valve would close on the loss of power, and the penetration can also be manually isolated. Since there were no modifications or additions required by EPU for these isolations, containment isolation is still maintained under EPU condition.

Reactor Coolant Inventory

As addressed in FSAR Section A1.3, Coping Analysis, sources of reactor coolant system leakage during an SBO are presumed to include normal system leakage (10 gpm) and each reactor coolant pump's (RCP) seal leakage (25 gpm/pump), for a total leakage of 60 gpm. The NRC analysis of the total volume of reactor coolant lost during the time period without power is less than the normal water volume in the pressurizer, including consideration of coolant heat-up effects. Once the AAC power source is on line and the normal reactor coolant makeup system is established, the pressurizer level will be restored to normal. Under these conditions, the reactor core will remain covered with the reactor coolant inventory for the duration of an SBO. There are no additional or revised components for the RCS system due to EPU. There are no changes in RCS system parameters which would decrease pressurizer water volume or increase system leakage. Therefore, there is no change in the loss of reactor coolant inventory due to EPU.

Auxiliary Feedwater Flow

The transient analysis performed for EPU to determine the auxiliary feedwater flow rate for current plant conditions required to remove decay heat and cooldown following an SBO event showed that a total flow rate of 275 gpm from the TDAFW pump was sufficient.

The TDAFW pump is capable of providing 275 gpm to the steam generators as currently designed. Therefore credit is taken for AFW flow from the unit specific turbine driven pump to provide the required additional flow. The EPU impact on required AFW flow is addressed in LR Section 2.5.4.5, Auxiliary Feedwater.

Other Issues

Other issues that are addressed for SBO are:

- Alternate AC Source: The Gas Turbine Generator and each Emergency Diesel Generator remain fully capable AAC sources with sufficient capacity and capability to operate systems necessary for coping with the required SBO duration with no changes due to EPU.
- Procedures and Training related to SBO: Procedures direct operators to restore power to the safety-related buses by EDG restart, offsite power reconnection, gas turbine generator start or opposite unit safety-related bus crosstie. Other procedures provide guidance for recovery from the station blackout condition once AC power has been restored. Appropriate training is implemented for any emergency AC power source configuration changes and remains unchanged by EPU.
- Quality Assurance Program: PBNP plant equipment originally classified as safety-related and required for SBO coping, is covered by the 10 CFR 50 Appendix B quality assurance program which meets or exceeds the guidelines of Appendix A of Regulatory Guide 1.155 Station Blackout (Reference 1). Non-safety-related components credited for coping in the PBNP SBO position have been assigned an Augmented Quality (AQ) classification which incorporates the QA program attributes. No change to these programs is required due to EPU.

License Renewal Evaluation

The impact of the uprate on individual systems, structures, and components credited for coping with a station blackout event is addressed in the LR Section for each system.

Results

The following can be summarized from the review of the specific issues related to the SBO:

- All the duration determination factors that would affect the SBO duration determination are unaffected by EPU. The coping duration remains unchanged.
- TS 3.7.6 minimum CST level must be increased from 13,000 gallon to 15,410 gallon for each unit. A single CST has sufficient capacity to supply the required quantity of water for both units, although the Service Water system is maintained as the safety related source of water to the Auxiliary Feedwater system after AC power is restored under EPU conditions.

- There are no additional loads added to the safety-related battery during an SBO at EPU conditions. The DC system remains adequate to support SBO.
- There are no requirements for additional compressed air during an SBO at EPU conditions.
- Room temperatures will remain below the maximum allowable temperatures during an SBO coping period and therefore the operability of SBO-related equipment in these rooms is not affected by the loss of ventilation at EPU conditions.
- Containment isolation capability is unchanged under EPU condition.
- The effect on the reactor coolant inventory is unchanged for EPU.
- There is an increase in required Auxiliary Feedwater flow due to EPU but the existing TDAFW pump is capable of providing the required flow for adequate removal of the reactor decay heat during an SBO event.
- All other SBO related issues such as AAC sources, procedures and training, and the Quality Assurance Program are unaffected by EPU.

Based on the review of the specific systems related to the SBO and their response to the event, the current PBNP SBO program is adequate under the EPU conditions.

2.3.5.3 Conclusions

PBNP has assessed 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. PBNP concludes that PBNP 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, PBNP finds the proposed EPU acceptable with respect to SBO.

2.3.5.4 References

1 NRC Regulatory Guide 1.155, Station Blackout, August 1988

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

2.4.1.1 Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. PBNP conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The PBNP review was also conducted to ensure that failures of the systems do not affect safety functions.

The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a) (1), 10 CFR 50.55a(h), and the following 10 CFR 50 Appendix A General Design Criteria (GDC):

- GDC 1, insofar as it requires that structures, systems and components (SCCs) important to safety are designed, fabricated, erected, and tested to quality standards commensurate with their importance to functions to be performed.
- GDC 4, insofar as it requires that SSCs be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC 13, insofar as it requires that instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC 19, insofar as it requires that a control room is provided from which actions can be taken to operate the nuclear unit safely under normal conditions, and maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCAs).
- GDC 20, insofar as it requires protection systems be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of important-to-safety systems and components.

- GDC 21 insofar as it requires protection systems be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated.
- GDC 22 insofar as it requires protection systems be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis.
- GDC 23 insofar as it requires protection systems be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.
- GDC 24, insofar as it requires that the protection system is separated from the control systems to the extent that a system satisfying all reliability, redundancy, and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 1, 4, 13, 19, 20, 21, 22, 23 and 24 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

PBNP GDC 1 broadly applies to plant equipment, including instrumentation and controls, and is discussed in FSAR Section 4.1, Reactor Design, Design Basis. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

The plant is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions.

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

Instrumentation and controls are provided to monitor and maintain important reactor parameters (including neutron flux, primary coolant pressure, loop flow rate, coolant temperatures, and control rod positions) within prescribed operating ranges. Other instrumentation and control systems are provided to monitor and maintain, within prescribed operating ranges, the temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment, and other auxiliary systems. Process variables which are required on a continuous basis for the startup, power operation, and shutdown of the plant are indicated, recorded, and controlled from the control room, which is a controlled access area. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

CRITERION: Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core. (PBNP GDC 13)

Ex-core nuclear instrumentation is used primarily for reactor protection, by monitoring neutron flux and by generating appropriate trip and alarm functions for various phases of reactor operating and shutdown conditions. Nuclear instrumentation also provides a fission process control function and indicates reactor fission process status during startup and power operation.

CRITERION: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (PBNP GDC 14)

If the reactor protection system sensors detect conditions which indicate an approach to unsafe operating conditions that require core protection, the system actuates alarms, prevents control rod motion, initiates load runback, and initiates reactor trip by opening the reactor trip breakers.

CRITERION: Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features. (PBNP GDC 15)

Instrumentation and controls provided for the engineered safety features actuation system are designed to automatically initiate engineered safety features (ESF) equipment during those accidents which are mitigated by automatic ESF equipment operation. Actuated ESF equipment (depending on the severity of the condition) includes the Safety Injection System, the Containment Air Recirculation Cooling System, containment isolation, and the Containment Spray System, as discussed in FSAR Section 6.0, Engineered Safety Features Criteria.

The engineered safety features actuation system consists of redundant analog channels, each containing sensors for different trip parameters, channel circuitry, and trip bistables. The trip bistable outputs are combined in coincident trip logic in two redundant actuation trains. Sufficient redundancy is provided so that a single failure will not defeat the actuation function.

CRITERION: Protection systems shall be designed for high functional reliability and inservice testability necessary to avoid undue risk to the health and safety of the public. (PBNP GDC 19)

A minimum of two independent protection channels are provided in the reactor protection system and engineered safety features actuation system for each trip variable, with most variables having three or four independent channels. Protection system reliability to avoid unnecessary trips is provided by redundancy within each tripping function and the use of coincidence trip logic. Each protection channel associated with any specific trip variable is provided with an independent source of electrical power and independent circuitry from the sensor through the trip bistable. Therefore, in the event that the loss of a single protection channel occurs, only that particular protection channel is affected, and coincidence logic is not satisfied to initiate a protective action (unless a one-out-of-two coincidence logic is employed).

Most protection channels are designed so that on loss of power, the bistables fail in the tripped condition (the preferred failure direction for most protection channels).

Protection channels are designed with sufficient redundancy for individual channel calibration and testing during power operation without degrading the protection functions. To remove an analog channel from service for test, calibration, or maintenance, all of the associated channel's trip signals to the reactor protection system or engineered safety features actuation system are first placed in the tripped condition. Tripping a channel to be tested will not cause a reactor trip or ESF actuation unless a trip condition already exists in a redundant channel.

CRITERION: Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. (PBNP GDC 20)

A minimum of two independent protection channels are provided in the reactor protection system and engineered safety features actuation system for each trip variable, with most variables having three or four independent channels. The design is such that no single failure within the protection systems or their supporting systems will defeat the overall protective function or violate protection system design criteria. The design includes redundant, independent channels extending from sensors to the trip bistable outputs, which are then combined into coincidence trip logic in two redundant logic trains that extend to the final actuated devices. Sufficient redundancy and coincidence logic is included to reliably accomplish the protective functions if a single failure should occur, while also minimizing unnecessary protective actions due to single failures.

FSAR Section 7.2, Reactor Protection System and FSAR Section 7.3, Engineered Safety Features Actuation System, discuss certain protection system backup trips that may not fully meet the single failure criterion. However, failure of a backup trip does not prevent proper protective action of primary trips assumed in the accident analyses, and does not represent a loss of the protective function discussed in PBNP GDC 20.

When protection system sensors also supply signals for control functions, an isolation amplifier is used to fully isolate the control signal from the protection signal. Therefore, any control circuit failure is prevented from affecting the protection channel. In a few circuits which provide Main Control board annunciation and stop rod withdrawal, the safety and control functions are combined from the sensor through dual alarm units. In these circuits, a failure in the control portion of the circuit can cause the safety portion of the circuit to go to its trip position. This may result in initiation of protective action.

CRITERION: The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident shall not result in loss of the protection function or shall be tolerable on some other basis. (PBNP GDC 23)

Potentially adverse conditions to which redundant protection system equipment may be exposed include adverse environmental effects, fires, earthquakes, and missile hazards. The design and layout of protection system components precludes loss of the protection function as a result of adverse conditions to which the components may be exposed.

Physical and electrical separation of redundant protection system channels and trains is employed to reduce the probability of an external hazard, such as a fire or missile, impairing the protection function through a common mode failure. Separation of redundant analog channels originates at the process sensors and continues along the field wiring, through containment penetrations, to the analog protection racks. As mentioned previously under PBNP GDC 20, some sensors for pressurizer pressure and reactor coolant flow may share common sensing lines, but the consequence of a line failure (rupture) will not prevent a protective action from occurring.

Separation of redundant protection channel/train field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for redundant channels and trains. Separate, dedicated racks for each channel and train are provided to terminate the field wiring, so that internal wiring within a rack is limited to a single channel or train. Power supplies to redundant channels and trains are provided from separate 120 VAC instrument buses and from separate DC buses, respectively.

FSAR Section 7.2, Reactor Protection System and FSAR Section 7.3, Engineered Safety Features Actuation System, discuss certain protection system backup trips that may not fully meet wiring separation criteria for redundant trains. However, failure of a backup trip circuit does not prevent proper protective action of primary trips assumed in the accident analyses, and does not represent a loss of the protective function discussed in PBNP GDC 23.

Environmental qualification of electrical/electronic equipment is addressed in FSAR Section 7.2.3.5, Environmental Qualification of Reactor Protection System Equipment.

Seismic qualification of protection system components is addressed in FSAR Section 7.2.3.4, Seismic Qualification of Protection System Equipment.

CRITERION: Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred. (PBNP GDC 25)

During power operation, each reactor protection channel and logic train is capable of being calibrated and tripped independently by simulated signals to verify its operation, without tripping the plant. The testing scheme includes checking through the trip logic to the reactor trip breakers. Therefore, the operability of each channel and logic train can be determined conveniently and without ambiguity.

During power operation, each engineered safety features actuation channel and logic train is capable of being calibrated and tripped independently by simulated signals to verify its operation up to the final actuation device. Because ESF equipment actuation would adversely impact plant operation at power, the final ESF actuation devices are not cycled while the reactor is at power. A resistance check of the relay coils is performed at power, but actuation of ESF equipment is performed during refueling shutdowns, rather than at power.

CRITERION: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced. (PBNP GDC 26)

Each reactor protection channel and train is designed on the "de-energize to operate" principle; an open circuit or loss of power causes the respective channel or train to go into its tripped condition (the "preferred failure" direction).

The analog channels for the ESFAS, with the exception of containment spray actuation, are designed on the same "de-energize to operate" principle as the reactor protection channels. The high-high containment pressure channels for containment spray actuation are designed as energize-to-operate, to avoid spray operation on inadvertent channel power failures.

Regarding the two ESF actuation trains, the output relays are "energize-to-operate" and require power to actuate ESF equipment. This design prevents inadvertent ESF equipment actuation on power failure of an actuation train (the "preferred failure" direction).

FSAR Chapter 7, Instrumentation and Control, addresses the design features and functions of the reactor protection system, engineered safety features actuation system and other reactor control systems and instrumentation.

In addition to the evaluations described in the FSAR, PBNP's electrical and instrumentation and control (I&C) systems were evaluated for plant license renewal. The evaluation of the electrical and I&C components, and the subsequent review and conclusions are discussed in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December, 2005 (Reference 1)

Electrical and instrumentation and controls are described in SER Section 2.5 and SER Section 3.6.

2.4.1.2 Technical Evaluation

2.4.1.2.1 Introduction

With respect to the EPU, the reactor protection system, (RPS), engineered safety features actuation system (ESFAS), the reactor control systems, and balance of plant (BOP) instrumentation are potentially impacted by the increase in reactor thermal power. NRC SE for PBNP Technical Specification Amendments: Re Loss of Power Diesel Generator Start Instrumentation dated March 21, 2007 (Reference 3), provided the following conclusion. PBNP has used Regulatory Guide (RG) 1.105, Revision 3, Setpoints for Safety-Related Instrumentation, which describes a method acceptable to the NRC staff for complying with the NRC's regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. The RG endorses Part I of ISA-S67.04-1994, Setpoints for Nuclear Safety Instrumentation, subject to the NRC staff clarifications.

2.4.1.2.2 Input Parameters and Assumptions

The design parameters associated with the EPU are identified in LR Section 1.1, Nuclear Steam Supply System Parameters. The initial best estimate nominal operating parameters are also identified in LR Section 1.1, Nuclear Steam Supply System Parameters. The BOP parameters are derived from the heat balance.

2.4.1.2.3 Description of Analyses and Evaluations

The effects of the EPU have been evaluated for normal operation, operational transients, and accident conditions described in the FSAR. These analyses used the most conservative combination (where appropriate) of Nuclear Steam Supply System (NSSS) design values from LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. In addition, these analyses included changes to specific RPS, control system, BOP and engineered safety features actuation system (ESFAS) setpoints. The results of the transient and accident analyses are described in the following LR section:

- LR Section 2.4.2, Plant Operability
- LR Section 2.6, Containment Review Considerations
- LR Section 2.8.5, Accident and Transient Analyses

2.4.1.2.3.1 Balance of Plant

2.4.1.2.3.1.1 Description of Balance of Plant Analyses and Evaluation

Operation of the plant at EPU conditions has minimal effect on BOP system instrumentation and control devices. Based on EPU operating conditions for the power conversion and auxiliary systems, most process control valves and instrumentation have sufficient range/adjustment capability for use at the EPU conditions.

The evaluation methodology used to evaluate the BOP system instrumentation includes the following basic steps:

- Perform system analysis to determine how the EPU conditions/ranges/setpoints compare to the current operating conditions/ranges/setpoints for the BOP systems
- For those systems (subsystems) that are impacted by the EPU, determine the major process instrumentation or board-mounted instruments from the piping and instrument diagrams (P&IDs) and instrument scaling calculations and tabulate the pre-EPU and post-EPU process data
- Analyze the affected instruments to determine EPU instrument impact
- For those instruments affected by the EPU, recommend new scaling, setpoints, ranges, or a suitable replacement (if required)

BOP system instrumentation evaluated (except items that are part of or provide input to the NSSS and/or the main turbine control system) included the following fluid systems:

- Main steam system (FSAR Section 10.1)
- Condensate and feedwater system (FSAR Section 10.1)
- Heater drain system (FSAR Section 10.1)
- Circulating water system (FSAR Section 10.1)
- Auxiliary Feedwater system (FSAR Section, 9.0)
- Component cooling water system (FSAR Section 9.1)
- Condenser steam dump system (FSAR Section, 7.7 and 10.1)
- Turbine generator system (FSAR Section 10.1)
- Extraction steam system (FSAR Section 10.1)
- Steam generator blowdown system (FSAR Section 10.1)
- Spent fuel pool cooling and cleanup system (FSAR Section 9.9)
- Service water system (FSAR Section 9.6)
- Auxiliary Feedwater System (FSAR Section 10.2)

The EPU evaluation of BOP instrumentation and controls demonstrated that, except as noted below, the design of BOP instruments, ranges, and setpoints remains acceptable for EPU operation.

The existing BOP indicated spans for indicators located at the Alternate Shutdown Instrumentation and Control (ASIC) panels for monitoring steam line pressure and steam generator level, as identified in FSAR Section 7.5.4.2, Operating Control Stations, Indication and Controls provided outside the Control Room are unaffected at EPU conditions.

The existing BOP indicators located at the Auxiliary Safety Instrumentation Panels (ASIPs) for monitoring steam generator wide range level as identified in FSAR Page 7.5-5, are unaffected at EPU conditions.

The Regulatory Guide (RG) 1.97, Revision. 2 () monitored variables, as identified in FSAR Section 7.6, Instrumentation Systems, and summarized in FSAR Table 7.6-1, for monitoring BOP variables remain bounding at EPU conditions.

These variables are as follows:

- Main steam flow
- Main steam line pressure
- Main feedwater flow
- Condensate storage tank level
- Component cooling water (CC) header temperature
- Service water header pressure
- CC header pressure
- Steam generator level (wide and narrow range)

Condensate and Feedwater System

The condensate and feedwater system evaluation is described in LR Section 2.5.5.4, Condensate and Feedwater. As a result of this evaluation, the following modifications will be implemented:

- To regain operating margin when the power uprate occurs on the main feedwater system, the following setpoints will be changed:
  - Feedwater pump low feedwater pump suction pressure, open low pressure heater bypass valve. (PC-2273, adjust controller setpoint)
  - Feedwater pump low feedwater pump suction pressure, trip main feedwater pump
- Replace Main Feedwater flow transmitters for increased range
- Upgrade Feedwater Regulating Valve (FRV) internal trim with a trim having a higher rated Cv value, replace the pneumatic operator, and replace the analog positioner with a digital positioner. The FRVs and the FRV bypass valves will continue to close on receipt of a safety injection signal, steam generator water level high signal, or a low Tavg signal with a reactor

trip signal (FRV only). These valves close on a safety injection signal as backups to the new Feedwater Isolation Valves (FIVs)

- Install new Feedwater Isolation Valves (FIVs) in the main feedwater line to each steam generator just outside containment. These normally open valves will close on receipt of a safety injection signal to isolate main feedwater flow in the event of a steam line break inside containment
- Change the Control Room indicator scale plates and recalibrate/rescale the instrument loops for main feedwater flow
- Change the Control Room indicator scale plates and recalibrate/rescale the instrument loop for main feedwater pumps suction flow
- Change the Control Room indicator scale plates and recalibrate/rescale the instrument loop for heater drain pump discharge flow
- Increase the low level setpoint alarm for the condensate storage tank
- Change condenser low vacuum alarm setpoint
- Recalibrate/rescale LEFM electronics used for plant calorimetric input and adjustment for new high flow alarm setpoint

Main Steam System

The main steam system evaluation is described in LR Section 2.5.5.1, Main Steam. As a result of this evaluation, the following modifications will be implemented:

- Modify the electro-hydraulic control (EHC) system for opening sequence control of the HP turbine control valves to convert from partial arc admission to full arc admission to the HP turbine.
- Replace main steam flow transmitters for increased range
- Replace HP turbine exhaust to MSR local pressure indicators
- Change the Control Room indicator scale plates and recalibrate/rescale main steam flow loops
- Recalibrate/rescale HP turbine gland steam supply pressure transmitters
- Change the Control Room indicator scale plates and recalibrate/rescale HP turbine first stage pressure transmitters and the following interlocks:
  - Permissive P2 - Auto-Rod withdrawal stop at low power
  - Permissive P5 - Steam dump Interlocks
  - Permissive P7 - Block various trips at power
  - Permissive P20 - AMSAC (Anticipated Transient Without Scram (ATWS) mitigation system actuation circuitry (AMSAC))
  - Feedwater control input

Extraction Steam System

As a result of this evaluation, the following modifications will be implemented:

- Recalibrate/rescale fifth point heater pressure transmitters
- Recalibrate/rescale T-94A Preseparator tank pressure transmitters
- Recalibrate/rescale third point heater pressure transmitters
- Recalibrate/rescale second point heater pressure transmitters
- Recalibrate/rescale LP turbine crossover pressure transmitters

Condenser Steam Dump System

The condenser steam dump system evaluation is described in LR Section 2.5.5.2, Main Condenser. As a result of this evaluation, no modifications are required.

Auxiliary Feedwater System

The Auxiliary Feedwater (AFW) system will be modified from a shared system to a unitized system. The required AFW system modifications, including the instrumentation and control changes, are described in LR Section 2.5.4.5, Auxiliary Feedwater. This modification will require changes to the Main Control boards to modify some of the existing AFW controls and to add new controls for the new auxiliary feedwater pumps, valves, and instrumentation. The design modification process will verify that all instrumentation and control changes comply with both the existing I&C licensing basis and with the revised AFW licensing basis described in LR Section 2.5.4.5, Auxiliary Feedwater.

BOP Instrumentation and Controls Results

The changes to ranges and/or setpoints for BOP instruments will not change instrument or instrument loop functions. As a result of the EPU, there are no changes to the PBNP GDC 12 current licensing basis that the quantity and types of process instrumentation provided ensures safe and orderly operation of the plant nor will the changes affect separation, redundancy or diversity of the instrumentation and controls discussed above.

Plant Computer

The plant computer (also referred to as the plant process computer system) is described in FSAR Section 7.5.1.4, Operating Control Stations, Plant Process Computer System. Plant process computer system inputs that are affected by instrumentation scaling changes will be modified during the implementation phase of the EPU. However, the plant computer safety assessment and reactor thermal output functions as described in FSAR Section 7.5.1.4.a, Operating Control Stations, Safety Assessment System, and 7.5.1.4.b, Operating Control Stations, Feedwater Leading Edge Flow Measurement, will not change as a result of the EPU.

2.4.1.2.3.2 NSSS Analyses and Evaluations

The EPU analyses identified additional instrumentation and trip setpoint changes that are required to ensure DNB, RCS pressure, and secondary system pressure remain within the allowable design margins and the response to the design basis operational transients remain acceptable. These changes are described below. The EPU analyses determined that with the exception of the following instruments, the NSSS instrumentation ranges, scalings, and setpoints used in the reactor protection system (RPS), engineered safety features actuation system (ESFAS), and reactor control instrumentation remained adequate for EPU. The specific changes to these instruments are described in the following sections.

Point Beach Nuclear Plant previously determined that certain Allowable Values (AV) in existing Technical Specification Tables 3.3.1 RPS and 3.3.2 ESFAS should be revised to include instrument uncertainties. This commitment has been accounted for in the determination of Limiting Safety System Settings (LSSS) to replace As in the Technical Specifications (TS) Tables for functions that are affected by the EPU changes. In addition, other Lass are provided in the tables for functions not affected by EPU to make the Technical Specification Tables consistent and resolve the commitment. Specific Lass not affected by EPU that are included in this submittal to resolve the commitment are identified below. A discussion of the methods used to develop LSSS for use in TS Tables 3.3.1 and 3.3.2 is included in Attachment E to this submittal.

Overview of EPU-related Technical Specification LSSS Changes

This section summarizes the EPU-related changes to Limiting Safety System Settings (LSSS) for RPS and ESFAS setpoints. The changes are also discussed individually in later sections. In summary, TS Tables 3.3.1-1 (RPS Instrumentation) and 3.3.2-1 (ESFAS Instrumentation) are being revised to:

1. Change the column heading now titled "Allowable Value" to "Limiting Safety System Setting";
2. Add two new Notes to be applied to those RPS/ESFAS functions that have LSSS values; and
3. Change the LSSS values in the tables for individual Functions identified below

Addition of the new notes is consistent with the guidance contained in RIS 2006-17, NRC Staff Position on the Requirements of 10 CFR 50.36, Technical Specifications, Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels.

Column Heading Change

The column heading previously identified in TS Tables 3.3.1-1 and 3.3.2-1 as "Allowable Value" is being changed to "Limiting Safety System Setting" to be consistent with 10 CFR 50.36. As defined in 10 CFR 50.36, Limiting Safety System Settings are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. 10 CFR 50.36 requires that Limiting Safety System Settings (LSSS) be included in the Technical Specifications. The heading change is consistent with the requirement.

New Notes applied to LSSS Functions

The following notes are being added to TS Tables 3.3.1-1 and 3.3.2-1

Note 1: A channel is OPERABLE when both of the following conditions are met:

a. The as-found Field Trip Setpoint (FTSP) is within the COT acceptance criteria for the as-found value. The method used to determine the COT acceptance criteria is described in FSAR Section 7.2.

b. The as-left FTSP is reset to a value that is within the as-left tolerance at the completion of the surveillance. The channel is considered operable even if the as-left FTSP is non-conservative with respect to the LSSS provided that the as-left FTSP is within the established as-left tolerance band. The method used to determine the as-left tolerances is described in FSAR Section 7.2.

Note 2: If the as-found FTSP is outside its predefined as-found acceptance criteria,

a. Evaluation of corrective measures necessary to return the channel to service is implemented in applicable plant maintenance and operating procedures

b. The out-of-tolerance condition shall be entered into the Corrective Action Process

Both notes will apply to each of those RPS/ESFAS Functions in marked up Tables 3.3.1-1 and 3.3.2-1, except those Functions that contain "NA" in the LSSS column. The FSAR Section 7.2, Reactor Protection System, will be updated as part of the implementation of the TS.

Appendix E, Supplement to LR Section 2.4.1, provides additional information on the calibration and surveillance criteria applied to LSSSs, and how these requirements are incorporated into the design basis.

LSSS Changes

The LSSS changes proposed in this submittal will:

- Incorporate EPU safety analyses changes to setpoint Analytical Limits,
- Replace previous Allowable Values that were inconsistent with the LSSS calculations and Technical Specification presentation adopted in this submittal

Table 2.4.1-1, Summary of EPU- Related RPS Functions, LSSS and Analytical Limits and Table 2.4.1-2, Summary of EPU-related ESFAS Functions, LSSS and Analytical Limits below summarize the LSSS changes. The individual LSSS changes are described in more detail in RPS and ESFAS sections that follow the tables.

Classification of Setpoints by Function

RPS and ESFAS setpoints are classified into one of the following three categories based on the individual setpoint function and whether the setpoint is credited in the safety analyses to protect a safety limit:

Category A Setpoints for protective functions that have Analytical Limits in the safety analyses. The Analytical Limits establish not-to-exceed setpoint values that assure that a protective action occurs within the safety analysis assumptions to protect the reactor core and reactor coolant system Safety Limits (SL) identified in PBNP Technical Specification 2.1. Setpoints in this category are referred to as primary trips. Category A setpoints are SL related LSSSs

Category B Setpoints for protective functions that have no analytical limit in the safety analyses. These protective functions are included in the protection system for defense-in-depth, but are not specifically credited in the safety analyses. The setpoints for these protective functions are referred to as backup or anticipatory trips. Category B setpoints are non-SL related LSSSs and are associated with Process Limits instead of Analytical Limits.

Category C Setpoints for automatically removing protection system operating bypasses. These setpoints have no Analytical Limit in the safety analyses that protects a Safety Limit. Operating bypasses may also be referred to in the Technical Specifications as interlocks, permissives, or blocks. Setpoints for removing operating bypasses are not considered a protection system protective action (reactor trip or ESF actuation) that protects a Safety Limit. Category C setpoints are non-SL related and the LSSSs are determined based on the nominal field settings and as-found acceptance criteria instead of an Analytical Limit or a Process Limit.

LSSS Summary Tables

Table 2.4.1-1, Summary of EPU- Related RPS Functions, LSSS and Analytical Limits and Table 2.4.1-2, Summary of EPU-related ESFAS Functions, LSSS and Analytical Limits identify RPS and ESFAS Functions, respectively, whose Limiting Safety System Setting is proposed to be changed for EPU. For each setpoint, the table identifies:

- RPS (or ESFAS) Function
- TS Table Function No.
- Category (defined above)
- Is the Function affected by EPU? If "No", the Function is included in this submittal because of the TS Table change from AV to LSSS and the commitment to address instrument uncertainties
- The proposed value in TS table LSSS column

If the function is A Category A LSSS (SL-related LSSS), the table also includes:

- Current Analytical Limit
- EPU Analytical Limit
- Associated safety analyses

2.4.1.2.3.2.1 Reactor Protection System

The design bases and description of the Point Beach Reactor Protection System (RPS) is described in FSAR Section 7.2.1, Reactor Protection System, Design Bases, and includes a listing of the reactor trips, purpose of each trip, and any associated protection and control permissives. The RPS automatically trips the reactor to protect against reactor coolant system damage caused by high system pressure and to protect the reactor core against fuel rod cladding damage caused by a departure from nucleate boiling. The basic reactor tripping philosophy is to define a region of power and coolant temperature and pressure conditions allowed by the primary trip functions (overpower ΔT trip, overtemperature ΔT trip, and power range flux overpower trips). The allowable operating region within these trip settings is provided to prevent any combination of power, temperature, and pressure that would result in a departure from nucleate boiling with all reactor coolant pumps in operation.

Trip functions such as a high pressurizer pressure trip, low pressurizer pressure trip, loss-of-flow trip, and steam-generator low-low water level trip are additional primary trip functions credited in the safety analysis for specific accident conditions and mechanical failures. Primary trips are distinguished by having specific Analytical Limits in the safety analyses to protect safety limits. The Analytical Limit provides the starting point for determining the primary trip setpoint value. Other trip functions such as a high pressurizer water level trip, turbine trip, safety injection trip, nuclear source and intermediate range flux trips, and manual trip are provided to back up the primary trip functions and are not specifically credited in the safety analyses. As a result, backup trips do not have explicit Analytical Limits to anchor the trip setpoint values.

The following are descriptions of the RPS instrumentation and setpoint changes necessary to ensure the RPS will continue to satisfy its design functions at EPU conditions.

<u>RCS Temperature Instrumentation</u>

LR Section 2.8.5.0, Accident and Transient Analyses, made recommendations for the T_h, T_c, T_{avg} and ΔT instrument ranges and setpoints to ensure the instrumentation would provide the required indication, core DNB protection, and plant response during accidents and transients over the entire range of operation at EPU conditions. The current range of the T_h and T_c instruments (500° F- 650° F) and ΔT instruments (0° - 100° F) satisfies the recommended ranges. The T_{avg} instruments including indications will be recalibrated for a range as follows:

- T_{avg} range revised from 520°F - 620°F to 530°F - 630°F

Reactor Trip Function Change for EPU

<u>Power Range Neutron Flux - High Reactor Trip</u>

For EPU, the Analytical Limit for the power range neutron flux - high reactor trip is decreased to 116% RTP from the current value of 118% RTP for the Rod Withdrawal at Power event. The proposed TS Limiting Safety System Setting (LSSS) for this function is based on the Limiting Trip Setpoint established by calculation to avoid exceeding the EPU Analytical Limit, taking all instrument uncertainties into account. The following change is proposed for the LSSS value in TS Table 3.3.1-1:

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint
	Current	EPU	Current	EPU	Current and EPU
Power Range Neutron Flux - High	118% RTP	116% RTP	$\leq$ 108% RTP	$\leq$ 109% RTP	107% RTP

The nominal field setpoint has design margin with respect to the LSSS

Overtemperature ΔT (OTΔT) Reactor Trip

Typically the values for the OTΔT reactor trip setpoints constants are listed in the cycle-specific Core Operating Limits Report (COLR) for each fuel cycle. For the initial EPU startup, the OTΔT trip setpoint will be recalibrated with OTΔT constants changed as follows:

Parameter	Current	EPU
Analytical Limit	1.255	1.295
Constant K1	1.16	1.203
Constant K2	0.0149/°F	0.016/°F
Constant K3	0.00072/psi	0.000811/psi

Overpower ΔT (OPΔT) Reactor Trip

As with OTΔT reactor trip setpoint, the values for the OPΔT trip setpoints constants are listed in the cycle specific COLR for each fuel cycle. The accident and transient analyses determined the rate sensitive temperature portion of the setpoint and the f(ΔI) function are not necessary for the OPΔT trip circuit to provide the required protection for maintaining the fuel design limits. The OPΔT trip setpoint constants changed as follows:

Parameter	Current	EPU
Analytical Limit	1.14	1.165
Constant K4	1.10	1.118
Constant K5	0.0262/°F	0.0/°F
Constant K6	0.00103/psi	0.00123/psi for $T_{avg} \geq T$ 0.0°F for $T_{avg} \leq T$
Constant T	569°F	576°F

Pressurizer Pressure - Low Reactor Trip

For EPU, the Analytical Limit for the pressurizer pressure - low reactor trip is 1840 psig, increased from the current value of 1815 psig for the OPTOAX code analysis. The proposed LSSS value is based on the Limiting Trip Setpoint established by calculation to avoid exceeding the new Analytical Limit, taking all instrument uncertainties into account. The following change is proposed for the LSSS value in TS Table 3.3.1-1:

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint
	Current	EPU	Current	EPU	Current and EPU
Pressurizer Pressure Low	1815 psig	1840 psig	≥1905 psig	≥1860 psig	1925 psig

The LSSS value is for operation at 2250 psia. Currently, a separate LSSS value is also stated in Technical Specification 3.3.1 for operation at 2000 psia. The proposed LSSS value for EPU is for operation only at 2250 psia and no value is provided for operation at 2000 psia.

The nominal field setpoint has design margin with respect to the LSSS

Pressurizer Pressure - High Reactor Trip

For EPU, the Analytical Limit for the pressurizer pressure - high reactor trip is 2403 psig for the Loss of External Electrical Load/Turbine Trip analysis, a decrease from the current Analytical Limit of 2410 psig. The proposed LSSS value is based on the Limiting Trip Setpoint established by calculation to avoid exceeding the new Analytical Limit, including all instrument uncertainties. For this setpoint, the proposed LSSS value for EPU is the same as the current LSSS value for 2250 psia operation and no TS change is necessary.

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint
	Current	EPU	Current	EPU	Current and EPU
Pressurizer Pressure High	2410 psig	2403 psig	≤ 2385 psig	≤ 2385 psig	2365 psig

The LSSS value is for operation at 2250 psia. Currently, a separate LSSS value is also stated in Technical Specification 3.3.1 Function 7.b for operation at 2000 psia. The proposed LSSS value for EPU only applies for operation at 2250 psia and the value for operation at 2000 psia will be eliminated.

The nominal field setpoint has design margin with respect to the LSSS.

Steam Generator Narrow Range Water Level Low-Low Reactor Trip

The accident and transient analyses have determined that the Analytical Limit utilized in the Loss of Normal Feedwater/Loss of AC Power events is changed for the EPU. For these events, the steam generator water level low-low reactor trip is credited as a primary protection function with an Analytical Limit. The steam generator water level low-low reactor trip Analytical Limit for the Loss of Normal Feedwater/Loss of AC Power events is increasing from 17% to 20.0% of narrow range span (NRS). To account for the Analytical Limit change for EPU conditions and instrument channel uncertainties, the Technical Specification Limiting Safety System Setting will increase from ≥ 20.0% of span to ≥ 29.3% of span.

	Analytical Limit		Technical Specification LSSS		Field Setpoint	
Parameter	Current	EPU	Current	EPU	Current	EPU
Steam Generator Narrow Range Water Level Low-Low	17.0% Of Span	20.0% Of Span	≥20.0% Of Span	≥29.3% Of Span	25.0% Of Span	30.0% Of Span

The nominal field setpoint has design margin with respect to the LSSS

Reactor Trip System Interlock Changes for EPU

Power Range Neutron Flux, P-8

The power range neutron flux P-8 interlock is an operating bypass function that is not specifically credited in the safety analyses. The interlock safety function is to automatically reinstate single loop loss of coolant flow reactor trips when the trip functions are required on increasing power. For EPU, the P-8 setpoint needs to be lowered from the current nominal 50% to protect the reactor during a partial loss of flow event. Analysis requires that the P-8 setpoint limit reactor power to ≤ 45% when the P-8 permissive block is in effect. Based on a 10% instrument uncertainty assumed in the analysis, the P-8 nominal field setpoint is to be lowered to 35% RTP. The actual instrument uncertainty is less than this 10% assumption.

Based on a P-8 nominal field setpoint of 35%, and the proposed LSSS value is established by calculation as the upper as-found limit for the 35% RTP nominal setpoint. The LSSS value for the Technical Specification is selected based on the FTSP and the expected loop performance (upper as-found tolerance) between calibrations, rounded. The following change is proposed for the P-8 LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint	
	Current	EPU	Current	EPU
Power Range Neutron Flux, P-8	≤50% RTP	≤38% RTP	49% RTP	35% RTP

Power Range Neutron Flux, P-9

The power range neutron flux P-9 interlock is an operating bypass function that is not specifically credited in the safety analyses. The safety function of the interlock is to remove (unblock) the operating bypass automatically to reinstate the reactor trip on turbine trip functions when power is above the ability of the steam dump system to prevent a reactor trip on a load rejection. The nominal setpoint at which the trips are reinstated is being revised by EPU as a function of full design power T_{avg}. A nominal P-9 permissive setpoint of 50% RTP is adequate at operation with a full design power T_{avg} of ≥ 572°F and during end-of-cycle coastdown operation when T_{avg} decreases to < 572°F. The nominal P-9 permissive setpoint must be 35% during operation when full design power Tavg is below 572°F.

The LSSS value for the Technical specification is selected based on the FTSP and the expected loop performace (upper as-found tolerance) between calibrations, rounded. The following changes are proposed for the P-9 LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint	
	Current	EPU	Current	EPU
Power Range Neutron Flux, P-9	≤50% RTP	≤38% RTP or ≤53% RTP*	49% RTP	35% RTP or 50% RTP

* $\leq$ 38% RTP for full power $T_{avg} \leq$ 572°F or $\leq$ 53% RTP for full power $T_{avg} \geq$ 572°F and end-of-cycle coastdown

Reactor Trip Function Changes (Non-EPU)

The following changes to RPS setpoints are necessary to change the LSSS values in TS 3.3.1 at current conditions to account for instrument uncertainties. These changes are also acceptable for EPU conditions.

Power Range Neutron Flux - Low Reactor Trip

The power range neutron flux - low reactor trip is a primary trip for safety analyses of subcritical rod withdrawal, rod ejection, and steam line break (outside containment) events. The Analytical Limit of 35% RTP applies to both current operation and EPU. The proposed LSSS value is established by calculation to avoid exceeding the Analytical Limit to account for calculated uncertainties. The following change is proposed for the LSSS value:

	Analytical Limit	Technical Specification LSSS		Field Setpoint
Parameter	Current and EPU	Current	EPU	Current and EPU
Power Range Neutron Flux - Low	35% RTP	≤25% RTP	≤28% RTP	20% RTP

The nominal field setpoint has design margin with respect to the LSSS

Intermediate Range Neutron Flux

The intermediate range high flux reactor trip is a backup trip that is not specifically credited in the safety analyses. Therefore, the trip function lacks an analytical limit upon which to base the LSSS value. The LSSS value for the TS is selected based on the FTSP and the expected loop performance between calibrations, rounded. Due to the nature of this process, the expected performance upper limit was based on setting tolerance, measurement and test equipment accuracy, and a drift allowance. This calculation method provides a more conservative LSSS than assuming a process limit of 100% instrument span. The following change is proposed for the LSSS value:

	Technical Specification LSSS		Field Setpoint
Parameter	Current	Proposed	Current and Proposed
Intermediate Power Range Neutron Flux	≤40% RTP	≤43% RTP	25% RTP

The nominal field setpoint has design margin with respect to the LSSS

Pressurizer Water Level - High

The pressurizer water level high reactor trip is a backup trip that is not specifically credited in the safety analyses and does not have an Analytical Limit. A Process Limit of 100% of the instrument span is used to calculate the LSSS. The following change is proposed for the LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint
	Current	Proposed	Current and Proposed
Pressure Water Level - High	≤95% of span	≤85% of span	80%

The nominal field setpoint has design margin with respect to the LSSS

Steam Generator Water Level - Low

The steam generator water level low signal, coincident with steam flow/feedwater flow mismatch, provides a backup reactor trip that is not specifically credited in the safety analyses and therefore does not have an Analytical Limit. The low level backup trip function is necessary in the event that a control/protection interaction failure of the SG level low-low reactor trip function disables the reactor trip on low-low level. A Process Limit of 0%, the low limit of the instrument span, is used to calculate LSSS considering all instrument uncertainties

The LSSS is proposed to be changed as follows:

Parameter	Technical Specification LSSS		Field Setpoint
	Current	Proposed	Current and Proposed
SG Water Level - Low	"NA"	> 10% of span	30%

For this function, Point Beach has chosen to set the FTSP conservatively higher at 30% to be consistent with the Steam Generator Water Level Low-Low Reactor Trip setpoint. The nominal field setpoint has design margin with respect to the LSSS.

Reactor Trip System Interlock Changes (Non-EPU)

Intermediate Range Neutron Flux, P-6

The P-6 interlock is an operating bypass (permissive) function that is not specifically credited in the safety analyses. The safety function of the interlock is to remove (unblock) the P-6 operating bypass automatically to reinstate the source range neutron flux reactor trip on decreasing intermediate range power. This unblock safety function lacks an analytical limit upon which to base the LSSS value. The LSSS value for the Technical Specification is selected based on the FTSP and the as-found criteria, rounded. Due to the nature of this process, the expected performance lower limit was based on setting tolerance, measurement and test equipment accuracy, and a drift allowance. The following changes are proposed for the LSSS value and the FTSP:

Parameter	Technical Specification LSSS		Field Setpoint	
	Current	Proposed	Current	Proposed
Intermediate Range Neutron Flux, P-6	≥1E-10 amp	≥ 4E-11amp	1.5E-10 amp	1E-10 amp

The LSSS will ensure that the interlock bypass safety function is achieved. The nominal field set-point change sets the FTSP conservatively above the LSSS.

Power Range Neutron Flux, P-7

The power range neutron flux P-7 interlock is an operating bypass (permissive) function that is not specifically credited in the safety analyses. The safety function of the interlock is to remove (unblock) the P-7 operating bypass automatically to reinstate reactor trips on increasing power of approximately 10% RTP that are not required at lower power levels. The proposed LSSS value is based on the upper as-found limit for the P-7 field trip setpoint. The following change is proposed for the LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint
	Current	Proposed	Current and Proposed
Power Range Neutron Flux, P-7	< 10% RTP	≤ 13% RTP	10% RTP

The field setpoint will continue to assure that the required reactor trip functions are automatically reinstated below the lower range limit of the power range instrumentation. The proposed LSSS value reflects the upper as-found limit for the current nominal field setpoint.

Turbine Impulse Pressure, P-7

The turbine impulse pressure P-7 interlock is an operating bypass function that is not specifically credited in the safety analyses. The safety function of the interlock is to remove (unblock) the P-7 operating bypass automatically to reinstate reactor trips on increasing turbine power of a pproximately 10% that are not required at low power levels. The proposed LSSS value is based on the upper as-found limit established by calculation for the nominal turbine impulse pressure P-7 field trip setpoint. The following change is proposed for the LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint	
	Current	Proposed	Current	Proposed
Turbine Impulse Pressure, P-7	< 10% Turbine Power	≤ 13% turbine power	8% turbine power	10% turbine power

The proposed LSSS value will assure that the required reactor trip functions are automatically reinstated at low power. The proposed LSSS value is the upper as-found limit established by calculation for the proposed field setpoint.

Note that for EPU the input from turbine first stage pressure input will be recalibrated to actuate the P-7 permissive at the value consistent with the new 0% - 100% turbine power nominal first stage pressure range.

Power Range Neutron Flux, P-10

The power range neutron flux P-10 interlock is an operating bypass function that is not specifically credited in the safety analyses. The interlock safety function is to automatically reinstate two reactor trips (Intermediate Range Neutron flux and Power Range Neutron Flux - Low) that are required at low power levels on decreasing power of approximately 9% RTP. An upper and lower LSSS value is included for consistency with the STS. However, the lower LSSS is the value that protects the P-10 safety function. The proposed LSSS values are based on the upper and lower as-found limits established by calculation for the nominal P-10 field trip setpoint. The following changes are proposed for the LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint
	Current	Proposed	Current and Proposed
Power Range Neutron Flux, P-10	≥ 8% RTP and ≤ 10% RTP	≥ 6% RTP and ≤ 12% RTP	9% RTP

The field setpoint will continue to assure that the required reactor trip functions are automatically reinstated. The proposed LSSS values reflect the upper and lower as-found limits that are established by calculation for the current field setpoint.

2.4.1.2.3.2.2 Engineered Safety Features Actuation System

The engineered safety features actuation system (ESFAS) actuates various engineered safety features (ESF) to provide protection against the release of radioactive materials in the event of a loss-of-coolant accident or a secondary line break accident. The ESF systems also function to maintain the reactor in a shutdown condition. They also provide sufficient core cooling to limit the extent of fuel and fuel cladding damage and to ensure the integrity of the containment structure. These functions rely on the ESFAS and associated instrumentation and controls. The following identifies the changes to the ESFAS instrumentation, Analytical Limits, and settings being implemented as part of EPU.

EPU Changes

Main Steam Flow and Feedwater Flow Instrumentation Range Changes

The current main steam line flow and main feedwater flow transmitters require changes to support EPU. The transmitters are currently calibrated with a range of 0 – 4.0×10^6 lbm/hr which is near the predicted EPU nominal steam flow of 3.7×10^6 lbm/hr with a feedwater temperature of 390°F. The main steam and main feedwater flow transmitters will be recalibrated for a range of 0 - 5.0×10^6 lbm/hr. The expanded range ensures that the steam flow indication will continue to meet the required Regulatory Guide 1.97 (Reference 2) range of 110% of design flow plus provide additional scaling to ensure steam line isolation on high-high steam flow will occur within the flow instrumentation range.

Steam Line Pressure Low – Safety Injection (SI)

For EPU safety analyses, safety injection actuation on low steam line pressure is assumed to occur at 410 psia (395.3 psig) in the reactor core analyses for steam line failures at hot zero power and full power. This is an increase from the Analytical Limit of 335 psia (320.3 psig) at the current power level. The proposed LSSS value is established by calculation to avoid exceeding the EPU Analytical Limit assuming all instrument uncertainties.

The following change is proposed for the LSSS value:

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint
	Current	EPU	Current	EPU	Current and EPU
Steam Line Pressure Low - SI	320.3 psig	395.3 psig	≥ 500 psig	≥ 520 psig	530 psig

The nominal field setpoint has design margin with respect to the LSSS.

High and High-High Steam Line Flow – Steam Line Isolation (SLI)

The EPU safety analysis for core response to steam line failures at hot zero power determined that the process limit for the high-high steam line flow input to steam line isolation is 5.0 E6 lbm/hr based on the setpoint remaining within the upper range limit of the steam flow instrumentation. In addition, the EPU accident analysis for the steam line break release analysis (outside containment) determined that the analytical limit for the high steam line flow input to steam line isolation is 1.07 E6 lbm/hr. The changes to the ESFAS analytical limits and the effect on the LSSS values and field setpoints for both functions are shown in the following table:

Parameter	Analytical/Process Limit		Technical Specification LSSS		Field Setpoint	
	Current	EPU	Current	EPU	Current	EPU
Steam Line Isolation High High steam Flow (in lbm/hr)	4.0 E6 @ 806 psig	5.0 E6 @ 586 psig	≤ 4.0 E6 @ 806 psig	≤ 4.9 E6 @586 psig	3.86 E6 @ 806 psig	4.85 E6 @ 586 psig
Steam Line Isolation High Steam Flow (in lbm/hr @ 1005 psig)	0.97 E6	1.07 E6	≤ 0.66 E6	≤ 0.8 E6	0.47 E6	0.52 E6

The nominal field setpoint has design margin with respect to the LSSS

AFW Pump Start on Steam Generator Narrow Range Water Level Low-Low

The accident and transient analyses have determined that the Analytical Limit in the Loss of Normal Feedwater/Loss of AC Power events for AFW pump start is increased to 20% of narrow range span for the EPU. The existing Aanalytical Limit for AFW initiation for a Loss of Normal Feedwater/Loss of AC Power event is 17% of span. To account for the Analytical Limit change for EPU conditions and instrument channel uncertainties, the Technical Specification LSSS value will increase from ≥ 20% of span to ≥ 29.3% of span.

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint	
	Current	EPU	Current	EPU	Current	EPU
Steam Generator Narrow Range Water Level Low-Low	17%	20%	≥ 20% of span	≥29.3% of span	25%	30%

The nominal field setpoint has design margin with respect to the LSSS

Removal of Condensate Isolation Function (Table 3.3.2-1 Function 7)

For EPU, the Condensate Isolation function (Function 7 in TS Table 3.3.2-1) will no longer be required to support feedwater isolation and will be removed from TS 3.3.2. The addition of Feedwater Isolation Valves for EPU that automatically close on an SI signal will replace the CPCI function to provide redundant isolation (with MFRV and bypass valve isolation) of the main feedwater headers during safety injection.

Non-EPU Changes

The following proposed changes to ESFAS setpoints are necessary to make the LSSS values in TS 3.3.2 at current conditions consistent with the LSSS calculations and TS presentation adopted in this submittal. These changes are also acceptable at EPU conditions.

Containment Pressure High - SI

Safety injection initiation on high containment pressure is credited in the safety analyses for a steam line break inside containment. The safety analysis Analytical Limit for the function is 6 psig increasing and is not changing for EPU. The proposed LSSS value is based on the Limiting Trip Setpoint established by calculation to avoid exceeding the Analytical Limit. The following change is proposed for the LSSS value:

Parameter	Analytical Limit	Technical Specification LSSS		Field Setpoint
		Current	EPU	Current and proposed
Containment Pressure High - SI	6 psig	≤ 6 psig	≤ 5.3 psig	5 psig

The nominal field setpoint has design margin with respect to the LSSS.

Pressurizer Pressure Low - SI

Safety injection initiation on low pressurizer pressure is credited in the LOCA, steam line break, and steam generator tube rupture core response safety analyses. The most restrictive safety analysis Analytical Limit for the function is 1648 psig decreasing. However, the lower range limit for the pressurizer pressure narrow range instruments is 1700 psig. Therefore, the LSSS for this function is based on the more restrictive lower range limit (a Process Limit) to assure the function occurs within the instrument range. The proposed LSSS value is established by calculation to prevent the setpoint exceeding the lower range limit when uncertainties are included. The following change is proposed for the LSSS value:

Parameter	Analytical Limit	Technical Specification LSSS		Field Setpoint
		Current	Proposed	Current and proposed
Pressurizer Pressure Low - SI	1700 psig	≥ 1715 psig	≥ 1725 psig	1735 psig

The nominal field setpoint has design margin with respect to the LSSS.

Containment Pressure High High – Containment Spray (CS)

Containment spray initiation on high-high containment pressure is credited in the safety analysis for the steam line break inside containment analysis. The safety analysis analytical limit for the function is 30 psig increasing and is not changing for EPU. The proposed LSSS value is based on the Limiting Trip Setpoint established by calculation to avoid exceeding the Analytical Limit. The following change is proposed for the LSSS value:

Parameter	Analytical Limit	Technical Specification LSSS		Field Setpoint
		Current	Proposed	Current and proposed
Containment Pressure High High - CS	30 psig	≤ 30 psig	≤ 28 psig	25 psig

The nominal field setpoint has design margin with respect to the LSSS.

Containment Pressure High High - SLI

Steam line isolation on high-high containment pressure is not specifically credited in the safety analyses for a steam line break inside containment. Therefore, the trip function lacks an analytical limit upon which to base the LSSS value. The proposed LSSS value is based on maintaining the field setpoint as-found value below the historical process limit previously established for this setpoint (20 psig), minus instrument loop uncertainties. The proposed LSSS value is established by calculation. The following change is proposed for the LSSS value:

Parameter	Process Limit	Technical Specification LSSS		Field Setpoint
		Current	Proposed	Current and proposed
Containment Pressure High High - SLI	20 psig	$\leq$ 20 psig	$\leq$ 18 psig	15 psig

The proposed LSSS value change establishes the upper limit on the as-found field setpoint to remain within the historical process limit of 20 psig for steam line isolation on high-high containment pressure.
The nominal field setpoint has design margin with respect to the LSSS.

Low T_{avg} Interlock

The low T_{avg} interlock, coincident with safety injection and high steam flow, is credited in the safety analysis for the steam line break release analysis (outside containment) to generate a steam line isolation signal. The proposed LSSS value is established by calculation to avoid exceeding the analytical limit, including all instrument uncertainties. The following change is proposed for the LSSS value:

Parameter	Analytical Limit	Technical Specification LSSS		Field Setpoint
		Current	Proposed	Current and proposed
Low T_{avg} interlock	540°F	$\geq$ 540°F	$\geq$ 542°F	543°F

The proposed LSSS value change establishes the upper limit on the as-found field setpoint to remain within the assumptions of the safety analyses that credit the low T_{avg} interlock coincident with safety injection and high steam flow for steam line isolation.

The nominal field setpoint has design margin with respect to the LSSS.

Steam Generator Water Level High - Feedwater Isolation

Feedwater isolation on high steam generator level is not specifically credited in the safety analyses. Therefore, the trip function lacks an analytical limit upon which to base the LSSS value.

The proposed LSSS value is based on the process limit of the maximum reliable indication of the level instrumentation (97% level). The proposed LSSS value is established by calculation including all instrument uncertainties. The following change is proposed for the LSSS value:

Parameter	Process Limit	Technical Specification LSSS		Field Setpoint
		Current	Proposed	Current and proposed
SG Water Level High - Feedwater Isolation	97%	"NA"	≤ 90% Of Span	78%

The nominal field setpoint has design margin with respect to the LSSS.

SI Block Pressurizer Pressure

The SI block pressurizer pressure function is an operating bypass that is not specifically credited in the safety analyses. The safety function of the operating bypass is to remove the bypass automatically to reinstate SI actuation on low pressurizer pressure and low steam line pressure during RCS repressurization on a normal plant startup. The proposed LSSS value is based on the upper as-found limit established by calculation for the SI block nominal field setpoint. The following change is proposed for the LSSS value:

Parameter	Technical Specification LSSS		Field Setpoint	
	Current	Proposed	Current	Proposed
SI Block Pressurizer Pressure	≤ 1800 psig	≤ 2005 psig	1775 psig	2000 psig

The current field setpoint and LSSS value are based on a normal RCS operating pressure of 1985 psig (nominal), which existed prior to the year 2000 to address primary-to-secondary differential pressure issues. In the years 2000/2001, the normal RCS pressure on both units was returned to the original RCS pressure of 2235 psig (nominal) as part of the fuel upgrade program. This change will restore the SI block setpoint and LSSS value to values consistent with RCS operation at 2235 psig.

The proposed setpoint provides reasonable margin to both normal operating pressure and the pressurizer pressure low SI setpoint. The LSSS value provides an as-found limit for the proposed field setpoint that supports the required function of an operating bypass.

2.4.1.2.3.3 Control Systems

The various reactor control systems are described in FSAR Section 7.7, Control Systems. The reactor control systems are designed to limit nuclear plant transients for prescribed design load perturbations, under automatic control, within prescribed limits to preclude the possibility of a reactor trip in the course of these transients. During steady-state operation, the primary function of the reactor control is to maintain a programmed average reactor coolant temperature that rises in proportion to load. The control systems also limit nuclear plant system transients to prescribed limits about this programmed temperature for specified load perturbations. Supervision of both the nuclear and turbine generator plants is accomplished from the control room. This supervision includes the direction for periodically testing of the RPS.

The current design basis operational transients described in FSAR Section 7.7.1, Control Systems, Rod Control System, are:

- Step-load increase of $\pm$10%, or ramp-load increase of 5% per minute within the load range of 15% to 100% of rated power
- Step-load decrease of 10% or ramp-load decrease of 5% per minute within the load range of 100% to 15% of rated power
- 50% load loss from any power level with steam dump
- Net loss of electrical load or turbine trip below 50% power with steam dump

The design basis 50% load loss for EPU has been changed to the equivalent of 50% of the EPU rated thermal power (RTP) at a maximum turbine unloading rate of 200% per minute. The 50% load loss at a maximum rate of 200% per minute is more realistic than a step change and is consistent with uprating projects previously performed on other Westinghouse plants.

The analyses evaluating the response to design basis operational transients at EPU conditions are described in LR Section 2.4.2, Plant Operability. The acceptable response to the design basis operation transients and accidents and transients associated with control system failures are based on the changes described for the rod control system and steam dump system being implemented.

Turbine First Stage Pressure Instrumentation

When the turbine generator is on line, turbine first stage pressure increases essentially linearly from 0%–100% turbine load and provides a close correlation of secondary power to reactor power. This allows turbine first stage pressure to be used as a reliable input demand signal or permissive to the various reactor control systems between 0% and 100% reactor power. The pre-EPU 0%–100% turbine load turbine first stage correlates to 0–544 psig. For EPU, a new HP turbine rotor is being installed which currently is expected to generate a 0%–100% power nominal first stage turbine pressure of 0–664 psig. Actual full power turbine first stage pressure may change slightly as the HP turbine design is refined and instrument calibrations will be revised accordingly.

The existing turbine first stage pressure transmitters and associated indications will be recalibrated and scaled to a range of 0 – 664 psig. The span of the turbine first stage pressure transmitters is 0 – 800 psig. The inputs to each of the following systems will be recalibrated to respond at the appropriate value for the new 0–100% power nominal turbine first stage pressure of 0–664 psig.

- AMSAC - arm/disarm circuit permissive P-20 at first stage pressure equivalent to 40% turbine power
- P-2 Permissive - blocks Automatic Rod Withdrawal block at less than 15% turbine load

- P-7 Permissive- in conjunction with P-10, bypasses low pressurizer pressure and low RCS flow, undervoltage, and under frequency trips
- T_{ref} input to the Reactor Coolant T_{avg} Control program
- EHC Turbine Control

Rod Control System Changes

The rod control system responds to changes in RCS temperature and secondary load as sensed by the RCS measured T_{avg} instrumentation and turbine first stage pressure instrumentation. The rod control system is designed to maintain average RCS temperature within ±1.5°F of the 0%–100% T_{avg} program reference value (T_{ref}) derived from 0–100% power turbine first stage pressure (0–664 psig). In addition, the rod control system responds to deviations between the reactor power and turbine load as sensed by the mismatch between power range instruments and turbine first stage pressure instrumentation. Both the T_{avg} program and the power mismatch program control rod speed and direction during normal and transient operation.

The EPU 0–100% power T_{avg} temperature program (T_{ref}) is changing from the current 547°F to 570°F to 547°F to 577°F based on a 0 – 664 psig turbine first stage pressure. Once the T_{ref} program is calibrated with the turbine first stage pressure range and temperature control band, the rods are expected to respond as designed to T_{avg} temperature deviations from T_{ref}.

The power mismatch circuits will be calibrated with the new 0–100% turbine first stage pressure values which will ensure the power mismatch circuits will continue to provide maximum rod speed with a deviation between nuclear power and turbine power of 10%.

Pressurizer Level Program

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with high measured T_{avg}. The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off and letdown isolation occurs while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions.

Analyses described in LR Section 2.4.2.2, Pressurizer Control Component Sizing, and LR Section 2.8.5.0, Non-LOCA Analyses Introduction, determined the nominal pressurizer level program for EPU must be changed from the current 20% - 45.8% program to a new nominal program of 20% at no load conditions to 47% for a full power T_{avg} of 577 F.

Low limit = 20% span at no-load temperature of T_{avg} 547°F

High limit = 47% span at full load temperature of T_{avg} 577°F

The level control program is linear between no-load and full T_{avg}. For measured T_{avg} above full load T_{avg} the level program is constant at the high limit.

Steam Dump Control and Turbine Bypass Systems

The steam dump control and turbine bypass system is comprised of the steam generator atmospheric dump valves (ADVs) and the condenser steam dumps. The ADVs can be used to remove sensible heat stored in the RCS at shutdown and cooldown when the condenser steam dumps are not available. The condenser steam dump system removes sensible heat stored in the RCS for a large rapid load decrease or a reactor trip on a turbine trip. With condenser steam dump not available, a large rapid turbine load reduction would result in a large steam pressure increase and could potentially challenge the Main Steam Safety Valves (MSSVs). Steam is dumped in order to remove the stored heat in the primary system at a rate fast enough to prevent lifting of the MSSVs for a large rapid load decrease, or a reactor trip. The evaluation of the steam bypass system is described in LR Section 2.5.5.3, Turbine Bypass, and LR Section 2.4.2, Plant Operability.

With the condenser available, the condenser steam dumps (groups A - D) are armed based on a rapid decrease in turbine first stage pressure (equivalent to >10% load decrease) and the dump valves either modulate open or are tripped open based on the magnitude of error (ΔT) between the measured T_{avg} and the reference temperature (T_{ref}) programmed off turbine first stage pressure.

As described in LR Section 2.4.2, Plant Operability, the current steam dump valve capacity at EPU conditions is sufficient to accommodate a rapid load decrease equivalent to 50% reactor thermal power (RTP) at a rate of 200% per minute and a turbine trip without a reactor trip below the permissive P-9 setpoint of 50% power provided the full power T_{avg} is 572°F to 577°F. The permissive P-9 setpoint is 35% below the full power T_{avg} of 572°F. T_{avg} load rejection and T_{avg} turbine trip steam dump current setpoints are acceptable at EPU conditions for full power T_{avg} anywhere between 558°F and 577°F.

Anticipated-Transient-Without-Scram Mitigation System Actuation Circuitry (AMSAC)

The PBNP Anticipated Transien Without Scram Mitigation System Actuation Circuitry (AMSAC) as required by 10 CFR 50.62 is described in FSAR Section 7.4.1, Other Actuation Systems, Anticipated-Transient-Without-Scram Mitigation System Actuation Circuitry. The change to this circuitry is associated with the arming permissive P-20 which arms and disarms the circuit at a turbine first stage pressure equivalent to approximately 40% nuclear power, and recalibrating the turbine first stage pressure, steam flow, and feedwater flow inputs for the EPU full load values. The P-20 permissive will be recalibrated to arm/disarm at approximately 40% for the appropriate turbine first stage pressure consistent with the new 0% – 100% power nominal turbine first stage pressure range of 0 – 664 psig.

Additional Changes

As described in LR Section 2.8.5.0, Non-LOCA Analyses Introduction, and the subsequent non-LOCA sections, changes were required to setpoints and associated functions to support the EPU. Some of these changes resulted in changes to the Technical Specifications. They include changes to the MSSV actuation settings for the 2 highest setpoints and a reduction in the high pressurizer pressure safety analysis reactor trip setpoint from 2425 to 2418 psia. In addition, the high neutron flux safety analysis reactor trip was reduced from 118% to 116% RTP. The OTΔT and OPΔT reactor trip setpoints were recalculated to adequately protect core thermal limits at the uprated power level conditions. The lead/lag compensation on low steam line pressure safety injection signal was changed from the current values of 12 seconds / 2 seconds to 18 seconds / 2 seconds; the safety analysis setpoint for this function was also increased from 335 psia to 410 psia. The safety analysis low-low steam generator water level reactor trip setpoint was increased from its current value of 17% narrow range span (NRS) to 20% NRS. These changes are identified in LR Section 2.8.5.0, Table 2.8.5.0-9, Key Safety Analysis Input Changes Made in Support of the PBNP EPU Program, and supported by non-LOCA safety analyses.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Safety related instrumentation or instrumentation that performs a function necessary to address one of the five regulated events are scoped within license renewal, however instruments typically are scoped as active components and are excluded from aging management review. Cables, connectors, pipes and tubes that service the in-scope instruments are passive and require aging management review and are addressed in other sections of this LR. No new protection or control systems were added to the scope of license renewal as a result of the EPU. The changes to instrumentation as a result of the EPU are predominately rescaling and recalibration of existing instrumentation and introduce no added components or configuration of the instruments. The rescaling and recalibration of these instruments do not impact the design function of the instruments and do not effect the conclusions stated in the license renewal evaluations. Therefore, the conclusions reached in NUREG 1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant Units 1 and 2, remain valid for the EPU.

For the limited number of cases discussed above, instruments or active instrument components must be changed to ensure the operability of the instruments for EPU conditions. These instrument changes are being performed in accordance with the plant modification process which evaluates the impact of the change with regard to license renewal and aging management.

2.4.1.3 Results

The changes to the instrumentation and controls for EPU are the result of accident and transient analyses and system evaluations to verify the systems and controls will continue to provide the required indication, protection actions, and plant response as originally designed. The changes ensure the DNB values remain within acceptable limits and the RCS pressure boundary, main steam pressure boundary, and containment boundary are all maintained within the design values. There are no new protection or control systems required to support EPU. The identified instrumentation recalibration and instrument rescaling will ensure the instrumentation continues to allow monitoring of plant process parameters during normal, transient and accident conditions and provide protective functions as required.

2.4.1.4 Conclusion

PBNP has reviewed the instrumentation and control systems relevant to the effects of the proposed EPU on the functional design of the reactor protection, safety features actuation, and control systems. PBNP concludes that the evaluation has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU (including the proposed changes to the Technical Specification listed in the preceding section, Setpoint Changes and Instrument Changes) are consistent with the plant's design basis, including the revised load rejection design basis to a rapid ramp load reduction equivalent to 50% rated thermal power at a maximum unloading rate of 200% per minute. PBNP further concludes that the systems will continue to meet the PBNP current licensing basis with respect to the requirements of PBNP GDC 1, 11, 12, 13, 14, 15, 19, 20, 23, 25, and 26. Therefore, PBNP finds the proposed EPU acceptable with respect to instrumentation and controls.

2.4.1.5 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 Regulatory Guide 1.97, Revision 2, Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, December 1980

3 NRC to PBNP SE for PBNP Technical Specification Amendments: Re Loss of Power Diesel Generator Start Instrumentation, dated March 21, 2007

Table 2.4.1-1
Summary of EPU- Related RPS Functions, LSSS and Analytical Limits

Reactor Trip Function	TS Table 3.3.1-1 Function No.	Setpoint Category	SL-related LSSS?	Proposed LSSS Column Value	Current Analytical Limit	EPU Analytical Limit	Related Safety Analyses
Power Range Flux - High	2.a	A	Yes	≤ 109% RTP	118% RTP	116%RTP	Rod Withdrawal at Power
Power Range Flux - Low	2.b	A	No	≤ 28% RTP	35% RTP	35% RTP	Rod Withdrawal from Subcritical RCCA Ejection
Intermediate Range Flux	3	B	No	≤ 43%RTP	-	-	-
Overtemperature ΔT	5	A	Yes	Unchanged	1.255* ΔT_o	1.295* ΔT_o	Rod Withdrawal at Power
Overpower ΔT	6	A	Yes	Unchanged	1.14 *ΔT_o	1.165 * ΔT_o	Steam System Piping Failure - HZP Steam System Piping Failure - Full Power
Pressurizer Pressure - Low	7.a	A	Yes	≥ 1860 psig	1830 psig	1855 psig	OPTOAX
Pressurizer Pressure - High	7.b	A	Yes	≤ 2385 psig	2425 psig	2418 psig	Loss of External Electrical Load/Turbine Trip
Pressurizer Water Level - High	8	B	No	≤ 85% of span	-	-	-
Steam Generator Water Level - Low Low	13	A	Yes	≥ 29.3% of span	17% of span	20% of span	Loss of Normal Feedwater Loss of All AC to Station Auxiliaries
Steam Generator Water Level - Low	14	B	No	≥ 10% of span	-	-	-
Permissive P-6	17.a	C	No	≥ 4E-11 amp	-	-	-
Permissive P-7 Neutron Flux	17.b(1)	C	No	≤ 13% RTP	-	-	-
Permissive P-7 Turbine Impulse	17.b(2)	C	No	≤ 13% turbine power	-	-	-
Permissive P-8	17.c	B	Yes	≤ 38% RTP	-	-	-
Permissive P-9	17.d	C	Yes	(a)	-	-	-
Permissive P-10	17.e	C	No	≥ 6% RTP and < 12% RTP	-	-	-

(a) ≤ 38% RTP for full power T_{avg} ≤ 572°F or ≤ 53% RTP for full power ≥ T_{avg} 572°F and end-of-cycle coastdown

Table 2.4.1-2
Summary of EPU-related ESFAS Functions, LSSS and Analytical Limits

ESFAS Function	TS Table 3.3.2-1 Function No.	Setpoint Category	SL-related LSSS?	Proposed LSSS Column Value	Current Analytical Limit	EPU Analytical Limit	Associated Safety Analyses
SI Containment Pressure - High	1.c	A	Yes	≤ 5.3 psig	6 psig	6 psig	Steam System Piping Failure-HZP Steam System Piping Failure - Full Power
SI Pressurizer Pressure - Low	1.d	A	No	≥ 1725 psig	1700 psig	1700 psig (Process limit)	(Process limit is transmitter lower range limit - analyses use limits below the lower range limit)
SI Steam Line Pressure - Low	1.e	A	Yes	≥ 520 psig	410 psia	410 psia	Steam System Piping Failure - HZP Steam System Piping Failure - Full Power
CS Containment Pressure - High High	2.c	A	No	≤ 28 psig	30 psig	30 psig	Steam Line Break M&E Release (Inside Containment)
SLI Containment Pressure - High High	4.c	B	No	≤ 18 psig	-	-	-
SLI High Steam Flow	4.d	A	Yes	≤ 0.8 E6 lbm/hr	0.97 E6 lbm/hr	1.07 E6 lbm/hr	Steam Line Break M&E Release (Outside Containment)
Low T_{avg}	4.d	A	No	≥ 542°F	540°F	540°F	Steam Line Break M&E Release (Outside Containment)
SLI High-High Steam Flow	4.e	A	Yes	≤ 4.9 E6lbm/hr	4.0 E6 lbm/hr	5.0 E6 lbm/hr	Steam System Piping Failure - HZP
FW Isolation SG High-High Level	5.b	B	No	≤ 90% of span	-	-	-
AFW Steam Generator Water Level - Low Low	6.b	A	Yes	≥ 29.3% of span	20% of span	20% of span	Loss of Normal Feedwater Loss of All AC to Station Auxiliaries

Table 2.4.1-2
Summary of EPU-related ESFAS Functions, LSSS and Analytical Limits

ESFAS Function	TS Table 3.3.2-1 Function No.	Setpoint Category	SL-related LSSS?	Proposed LSSS Column Value	Current Analytical Limit	EPU Analytical Limit	Associated Safety Analyses
Condensate Isolation Containment Pressure	7.a	Function Deleted					
SI Block - Pressurizer Pressure	8	C	No	≤ 2005 psig	-	-	-

2.4.2 Plant Operability

2.4.2.1 Plant Operability (Margin to Trip)

2.4.2.1.1 Regulatory Evaluation

2.4.2.1.1.1 Introduction

The nuclear steam supply system (NSSS) instrumentation and control systems are required to respond to the initiation of design basis plant operational transients without initiating a reactor trip or engineered safety features signal. PBNP operational transients were analyzed to demonstrate that the NSSS instrument and control systems responses to these operational transients remain acceptable.

The acceptance criteria for the NSSS control systems are based on GDC 13, insofar as it requires that instrumentation and control systems be provided to monitor variables and systems over their anticipated ranges during normal operation and anticipated operational occurrences, and maintain these variables and systems within prescribed operating ranges.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 13 is as follows:

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

Instrumentation and controls are provided to monitor and maintain important reactor parameters (including neutron flux, primary coolant pressure, loop flow rate, coolant temperatures, and control rod positions) within prescribed operating ranges. Other instrumentation and control systems are provided to monitor and maintain, within prescribed operating ranges, the temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment, and other auxiliary systems. Process variables which are required on a continuous basis for the startup, power operation, and shutdown of the plant are indicated, recorded, and controlled from the control room, which is a controlled access area. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

The FSAR Sections 1.2.3, Summary Plant Description, Reactor and Plant Control, 4.1, Reactor Coolant System, Design Basis, and 7.5.1.2, Reactor and Turbine Generator Control Board, define the current design basis operational transients that PBNP must be able to sustain without initiating a reactor trip or an engineered safety feature (ESF) actuation signal as:

- Step-load changes of 10%, or ramp-load changes of 5% per minute within the load range of 15% to 95% of rated power

- Sustained reactor operation following a step-load rejection of 50% power with the condenser steam dumps and atmospheric dump systems available
- The condenser steam dumps and atmospheric steam dump systems make it possible to accept a step load decrease of 50% of full power without reactor trip, or a turbine trip from below 50% power without a reactor trip

FSAR Chapter 7, Instrumentation and Control, addresses the design features and functions of the reactor protection system, engineered safety features actuation system and other reactor control systems and instrumentation.

The adequacy of the PBNP instrumentation and control system design is discussed in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems.

In addition to the evaluations described in the FSAR, PBNP's electrical and instrumentation and control (I&C) systems were evaluated for plant license renewal. The evaluation of the electrical and I&C components, and the subsequent review and conclusions are discussed in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Electrical and instrumentation and controls in the scope of License Renewal are described in Sections 2.5 and 3.6 of the SER.

2.4.2.1.2 Technical Evaluation

2.4.2.1.2.1 Introduction

As described in the FSAR, Section 7.7, Control Systems, the current design basis operational transients that PBNP must be able to sustain without initiating a reactor trip or an engineered safety feature (ESF) actuation are:

- Step-load increase of 10%, or ramp-load increase of 5% per minute within the load range of 15% to 100% of rated power
- Step-load decrease of 10% or ramp-load decrease of 5% per minute within the load range of 100% to 15% of rated power
- Step-load decrease of 50% with steam dump
- Turbine trip below P-9 permissive setpoint of 50% power with steam dump

Analyses of the design basis transients were performed using the proposed EPU NSSS control system settings and setpoints to demonstrate adequate margin exists to relevant reactor trip and ESF actuation setpoints over the entire range of EPU operating conditions. The PBNP EPU operating conditions are shown in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1.

As part of EPU analyses, the definition of the design basis step-load decrease of 50% is revised as a rapid load decrease equivalent to 50% of the EPU rated thermal power (RTP) at a maximum turbine unloading rate of 200%/minute. This change in the licensing basis 50% load rejection from a step change to a ramp load change at a maximum rate of 200% per minute redefines the load rejection in a more realistic manner and is consistent with uprating projects previously performed on other Westinghouse plants. For the turbine trip load reject, the reactor is assumed to be below the P-9 permissive which defeats the reactor trip due to turbine trip when nuclear power is less than 50%.

Following implementation of EPU, the design basis operational transients will be defined as:

- Step-load change of ±10% or ramp load change of 5% per minute within the load range of 15% to 100% (90% for step load or ramp load increases)
- A rapid load decrease equivalent to 50% rated thermal power at a maximum turbine unloading rate of 200% per minute (50% load rejection) with steam dump
- Turbine trip below 50% reactor power (P-9) with steam dump for EPU design full power T_{avg} between 572°F and 577°F and 35% when full power T_{avg} is below 572°F

The 5% per minute loading and unloading transients are not limiting transients and are enveloped by the 10% step increase and decrease transients, respectively. Therefore, no specific analysis was performed for the 5% per minute loading and unloading transient.

The analyses were performed using the Westinghouse LOFTRAN computer code. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems. A LOFTRAN computer model was developed for PBNP at the EPU conditions. The degree of limitation of the above transients was analyzed to show that it resulted in acceptable plant response. Details of the analyses are described below.

2.4.2.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The following assumptions were made for all normal transients analyzed:

- All NSSS control systems (rod, pressurizer pressure, pressurizer level, and steam dump) are assumed to be operational and functioning as designed. The feedwater/steam generator level and pressurizer level control systems are not explicitly modeled; however, initial steam generator mass and pressurizer water level are input at the initial nominal operating conditions. Pressurizer PORVs were credited for the 50% load rejection transient.
- Analyses were performed both at high T_{avg} (full power T_{avg} = 577°F) and low T_{avg} (full power T_{avg} = 558°F) to cover the EPU full power T_{avg} design range of 558°F to 577°F. Analyses bound 0% to 10% average steam generator tube plugging level and the steam generator Models Δ47 and Model 44Fon Unit 2 and Unit 1, respectively.
- A 0.6% initial power level uncertainty was conservatively assumed for the plant operability analysis. The remainder of the plant parameters (that is, reactor coolant system (RCS) T_{avg}, pressurizer pressure, pressurizer level, steam generator level) were assumed to be at their nominal post EPU control system setpoints.
- Best estimate reactor kinetics (i.e., moderator temperature coefficient, Doppler power defect, and control rod worth, etc.) at the Beginning of Life (BOL) core conditions are used. The BOL values used are conservative for the margin to trip analysis.

- The analyses assumed reactor protection and control system settings initially derived from the EPU accident and transient analyses discussed in LR Section 2.8.5, Accident and Transient Analyses. These changes are listed below and specifically described as appropriate in detail in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems.
  - Proposed Technical Specification overtemperature and overpower ΔT constant values
  - Changes to the time constants in the overtemperature and overpower function
  - Changes to the lead time constant on the lead/lag of the low steam line pressure safety injection function
  - Changes to the P-9 permissive setpoint for EPU design full power T_{avg} below 572°F
  - The revised pressurizer level program for EPU was used for all analyses
  - The reactor protection setpoints used in this analyses are:
- High-pressurizer pressure reactor trip: 2365 psig
- Low-pressurizer pressure reactor trip: 1925 psig
  - Lead time constant = 10 seconds
  - Lag time constant = 1 second
- Low-pressurizer pressure SI: 1735 psig
- Low-steamline pressure SI: 530 psig
  - Lead time constant = 18 seconds
  - Lag time constant = 2 seconds
- Open-Shut T_{avg} Control of Feedwater Valves 554°F

2.4.2.1.2.3 Description of Analyses and Evaluations

Design operational transients were performed using the current capacity of the condenser steam dumps with the current steam dump valves settings. With current settings, these analyses achieved acceptable results at EPU conditions.

10% Step-Load Decrease

The 10% step-load decrease transient is intended to avoid the plant from reaching the pressurizer power-operated relief valve (PORV) setpoint. The 10% load decrease transient was analyzed as part of the pressurizer pressure control component sizing analysis described in LR Section 2.4.2.2, Pressurizer Control Component Sizing. The analyses performed for the spray capacity included additional conservatisms not normally used in the plant operability analyses, therefore enveloped the best-estimate analyses normally used in the plant operability analyses.

10% Step-Load Increase

This transient was analyzed to verify that there is adequate margin to the low pressurizer pressure and power range neutron high flux reactor trip setpoints and the engineered safety features actuation function on low-steam line pressure. This transient was analyzed as a step-load increase from 90% to 100% power with all NSSS control systems active, except the steam dump control system (steam dump is not activated for 10% step-load changes).

50% Load Rejection

The 50% load rejection transient was analyzed as a rapid ramp load decrease of 200% per minute rather than a step change. This is more realistic and representative of an actual load rejection transient in the plant and is consistent with uprating projects previously performed on other Westinghouse plants.

A 50% load rejection transient is the most severe operational transient that the plant would normally undergo without potentially actuating a reactor trip or engineered safety features function. This transient was analyzed as a rapid change in turbine load from 100% to 50% of the nominal power level at a maximum 200% per minute turbine unloading rate.

Turbine Trip from P-9 Permissive Setpoint

This transient was analyzed to verify that the pressurizer PORVs are not challenged on a turbine trip below the P-9 setpoint (NUREG 0737, item II-K.3.10, (Reference 2)). This transient was modeled as a step-load decrease in turbine load from the P-9 permissive setpoint power level to 0% power with all NSSS control systems active. This transient was analyzed for normal plant operation and for the End-of-cycle (EOC) T_{avg} coastdown maneuver conditions.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The components of the NSSS instrumentation and control system are treated for license renewal purposes as a commodity group discussed in the License Renewal SER, NUREG-1839 (Reference 1), Section 2.5, Scoping and Screening Results: Electrical and Instrumentation and Controls. The aging management programs applicable to this commodity group are discussed in SER Section 3.6, Aging Management of Electrical Components EPU activities are not adding any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operation of components do not add any new or previously unevaluated aging effects that would necessitate a change to an existing aging management program or require a new aging management program as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to license renewal scope, aging effects, and aging management programs due to EPU activities.

2.4.2.1.3 Results

These analyses concluded that the changes to the reactor protection and reactor controls identified in LR Section 2.4.2.1.2.2, Input Parameters, Assumptions, and Acceptance Criteria, above, will enable the plant to continue to satisfy the requirements of the design operational transients listed below.

5%/Minute Loading and Unloading

Acceptable results were obtained for the 10% step-load increase and decrease, 50% load rejection, and turbine trip without reactor trip transients which envelop the 5% per minute loading and unloading transients. Therefore, the response to a 5% per minute unit loading and unloading transients at EPU conditions is acceptable.

10% Step-Load Decrease

The design basis for this transient is that a 10% step-load decrease transient can be accommodated without challenging the pressurizer PORVs or resulting in a reactor trip or ESF actuation. The analyses show the pressurizer pressure remains below the PORV setpoint and the control system response was smooth during the transient with no oscillatory response noted. Therefore, the response to a 10% step-load decrease transient at EPU is acceptable.

The results indicated that no reactor trip setpoints were challenged and the control system response was stable and not oscillatory. Pressurizer pressure reached a maximum of 2301 psig for the high T_{avg} case which is less than the 2335 psig PORV setpoint, therefore the PORVs were not challenged.

10% Step Load Increase

The analyses show the primary pressure remained well above the low pressurizer pressure trip and the main steam pressure remains above the low steam line pressure ESFAS actuation. The analyses indicate the control system response was smooth during the transient with no oscillatory response noted. Therefore, the response to 10% step-load increase transient at EPU is acceptable.

The control system response was smooth during the transient with no oscillatory response noted. No reactor trip or ESF actuation setpoints were challenged. The steam pressure reached a minimum of 544 psig (lead/lag compensated) at low T_{avg} conditions which is greater than the low steamline flow SI actuation setpoint of 530 psig. The compensated minimum steam pressure was 654 psig at high T_{avg} conditions. The minimum compensated pressurizer pressure reached was approximately 2195 psig, which is greater than the low-pressure reactor trip setpoint of 1925 psig. The power range neutron flux reached a maximum value of 102%, which is less that the reactor trip setpoint of 107%. Therefore, the plant's response for the 10% step-load increase transient is acceptable for the EPU.

50% Load Reduction

The design basis for this transient is that a 50% rapid ramp load reduction transient can be accommodated without challenging any reactor trip or ESF. The analyses for the most limiting case shows the pressurizer PORVs open and limit the pressurizer pressure to less than the high pressure trip and the minimum predicted pressurizer pressure remains well above the low pressure trip. The analyses indicate the control response is smooth and stable. Therefore the response to a 50% rapid ramp load reduction at EPU is acceptable.

Based on the analyses results, a 50% rapid load reduction at a turbine runback of 200% per minute can be sustained for full-power T_{avg} values in the 558°F to 577°F range. The limiting setpoints for a 50% rapid load reduction transient are; the OTΔT and OPΔT reactor trip setpoints.

A minimum margin to OTΔT reactor trip setpoint was 4.8% of nominal EPU ΔT at high T_{avg} (full power T_{avg} of 577°F) conditions. The minimum margin to OTΔT reactor trip setpoint was 18.6% of nominal EPU ΔT at low T_{avg} (full power T_{avg} of 558°F) conditions. There was adequate margin to the OPΔT reactor trip setpoint. Therefore, a 50% rapid load reduction transient will be acceptable for the EPU.

The PORVs will open for all cases analyzed for 50% rapid load reduction transient which limit the peak pressurizer pressure near the PORV setpoint of 2335 psig. There was adequate margin to the high pressurizer pressure reactor trip setpoint of 2365 psig. The minimum compensated pressurizer pressure was 2008 psig; therefore there is adequate margin to the low-pressurizer pressure reactor trip setpoint of 1925 psig.

Turbine Trip without Reactor Trip

The design basis for this transient is that a turbine trip without reactor trip transient actuated from below the revised P-9 setpoint can be accommodated without challenging the pressurizer PORVs or resulting in a reactor trip or ESF actuation. While not a design requirement, it is desirable to avoid actuating the steam generator power operated atmospheric dump valves (ADVs) and Main Steam Safety Valves (MSSVs) as well. The analyses show, for normal plant operation the current P-9 setpoint of 50% rated EPU power is acceptable provided the full power T_{avg} is no lower than 572°F. The P-9 setpoint for the full power T_{avg} between 558°F and 572°F is 35% of rated EPU power. For the EOC T_{avg} coastdown maneuver, the P-9 setpoint is 50% rated EPU power for full power T_{avg} anywhere between 558°F and 577°F. The analyses show the control system responses are smooth and stable. Therefore, the response to a turbine trip below P-9 permissive setpoint is acceptable.

The calculated peak pressurizer pressure was 2330 psig. Therefore there was adequate margin to the PORV setpoint of 2335 psig. The calculated peak pressurizer pressure was 2309 psig for the EOC T_{avg} coastdown maneuver conditions and therefore there was adequate margin to the PORV setpoint of 2335 psig for the EOC T_{avg} coastdown maneuver. The peak secondary side steam pressure was 1023 psig and therefore there was adequate margin to the main steam safety valves (MSSVs) lowest setpressure of 1085 psig and the atmospheric dump valve (ADV) set pressure of 1050 psig.

2.4.2.1.4 Conclusions

PBNP has reviewed the effects of the proposed EPU on the plant capability of meeting its response to design basis operational transients. PBNP concludes that it has adequately addressed the effects of the proposed EPU on the plant operational capability and that the changes that are necessary to achieve satisfactory results at EPU are consistent with the plant's design basis including the revised 50% load rejection definition to a rapid load ramp decrease equivalent to 50% of rated thermal power at a maximum unloading rate of 200% per minute. Therefore, PBNP finds that, with appropriately revised control settings, the responses of the plant to operational transients at the proposed EPU are acceptable with respect to the plants capability of meeting its design basis operational transients and continuing to meet the current licensing basis with respect to the requirements as specified in PBNP GDC 12. Therefore, PBNP finds the proposed EPU acceptable with respect to plant operability (margin to trip).

2.4.2.1.5 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980

2.4.2.2 Pressurizer Control Component Sizing

2.4.2.2.1 Regulatory Evaluation

The pressurizer pressure control system (consisting of the pressurizer heaters, spray, and power operated relief valves (PORVs)) provides the means of controlling the pressurizer pressure to less than the design basis setpoint value during steady-state operation and to minimize the pressurizer pressure excursions during design basis operational transients. PBNP conducted a review of the pressurizer pressure control system for the EPU to ensure that the system, and any changes necessary for the EPU, are adequately designed so that they continue to meet their design basis operational functions. The acceptance criteria related to the quality of design of the pressurizer pressure control systems are based on:

- 10 CFR 50.55a(a)(1), insofar as it requires that safety-related structures, systems, and components (SSCs) be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed.
- GDC 1, insofar as it requires that safety-related structures, systems, and components (SSCs) are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.
- GDC 13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC 19, insofar as it requires that a control room be provided from which actions can be taken to operate the nuclear unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCAs).
- GDC 24, insofar as it requires that the protection system be separated from the control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 1, 13, 19 and 24 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

PBNP GDC 1 broadly applies to plant equipment, including instrumentation and controls, and is discussed in FSAR Section 4.1, Reactor Coolant System, Design Basis. Quality standards of material selection, design, fabrication, and inspection conform to the applicable provisions of recognized codes and good nuclear practice.

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

The plant is equipped with a common control room which contains those controls and instrumentation necessary for operation of each unit's reactor and turbine generator under normal and accident conditions.

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

Instrumentation and controls are provided to monitor and maintain important reactor parameters (including neutron flux, primary coolant pressure, loop flow rate, coolant temperatures, and control rod positions) within prescribed operating ranges. Other instrumentation and control systems are provided to monitor and maintain, within prescribed operating ranges, the temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment, and other auxiliary systems. Process variables which are required on a continuous basis for the startup, power operation, and shutdown of the plant are indicated, recorded, and controlled from the control room, which is a controlled access area. The quantity and types of instrumentation provided are adequate for safe and orderly operation of all systems and processes over the full operating range of the plant.

CRITERION: Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. (PBNP GDC 20)

A minimum of two independent protection channels are provided in the reactor protection system and engineered safety features actuation system for each trip variable, with most variables having three or four independent channels. The design is such that no single failure within the protection systems or their supporting systems will defeat the overall protective function or violate protection system design criteria. The design includes redundant, independent channels extending from sensors to the trip bistable outputs, which are then combined into coincidence trip logic in two redundant logic trains that extend to the final actuated devices. Sufficient redundancy and coincidence logic is included to reliably accomplish the protective functions if a single failure should occur, while also minimizing unnecessary protective actions due to single failures.

FSAR Sections 7.2, Reactor Protection System, and 7.3, Engineered Safety Features Actuation System, discuss certain protection system backup trips that may not fully meet the single failure criterion. However, failure of a backup trip does not prevent proper protective action of primary trips assumed in the accident analyses, and does not represent a loss of the protective function discussed in PBNP GDC 20.

When protection system sensors also supply signals for control functions, an isolation amplifier is used to fully isolate the control signal from the protection signal. Therefore, any control circuit failure is prevented from affecting the protection channel. In a few circuits which provide main control board annunciation and stop rod withdrawal, the safety and control functions are combined from the sensor through dual alarm units. In these circuits, a failure in the control portion of the circuit can cause the safety portion of the circuit to go to its trip position. This may result in initiation of protective action.

FSAR Section 7.2.3.2.c, Reactor Protection System, Specific Control and Protection Interactions, addresses the pressurizer pressure control functions that derive their signals from the reactor protection system through isolation devices.

In addition to the evaluations described in the FSAR, PBNP's electrical and instrumentation and control (I&C) systems were evaluated for plant license renewal. The evaluation of the electrical and I&C components, and the subsequent review and conclusions are discussed in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

Electrical and instrumentation and controls are described in Sections 2.5 and 3.6 of the SER.

2.4.2.2.2 Technical Evaluation

2.4.2.2.2.1 Introduction

As part of the EPU, the following pressure control components were evaluated to ensure that the nuclear steam supply system (NSSS) pressure control system is adequate for the increased pressures and temperatures for the uprate conditions shown in LR Section 1.1, Nuclear Steam Supply System Parameters:

- Pressurizer power-operated relief valves (PORVs)
- Pressurizer spray valves

- Pressurizer heaters
- Condenser Steam dump valves

To support the PBNP Units 1 and 2 EPU, Westinghouse recommended new settings described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. These recommended new setpoints for pressurizer level control, reactor control, new time constant for low steam line pressure ESFAS actuation, and new setpoints and time constants for overtemperature delta-T (OTΔT) and overpower delta-T (OPΔT) reactor trip functions were used in this pressure control component sizing analysis. The pressure control component analyses were performed for Unit 2 with Model Δ47 steam generators which bounds Unit 1 with Model 44F steam generators. Analyses bound high and low full power feedwater temperatures and 0% to10% average steam generator tube plugging levels.

The components comprising the pressure control components are described in the FSAR Sections 4.1, Reactor Coolant System, Design Basis, 7.7.2, Control System, Condenser Steam Dump Control, 7.7.3.1, Control System, Pressurizer Pressure Control, and 10.1.2, Steam and Power Conversion System, System Design and Operation. Based on these descriptions, the following bases were used to evaluate the sizing acceptability of the various components of the pressure control system.

Pressurizer PORVs

The sizing basis for the pressurizer PORVs is to prevent the pressurizer pressure from reaching the high pressurizer pressure reactor trip setpoint for the design basis large load reduction with steam dump transient. This design basis large load reduction is defined as a 50% load reduction from 100% to 50% power at the maximum turbine unloading rate.

Pressurizer Spray Valves

The sizing basis for the pressurizer spray valves is to prevent challenges to the pressurizer PORVs for a 10% step-load decrease transient. For load decreases up to 10% power, the spray valves are the prime means of controlling pressure without actuating the pressurizer PORVs when in automatic pressure control mode.

Pressurizer Heaters

The pressurizer heaters are sized to be able to heat up the pressurizer liquid at a maximum rate of a 55°F per hour during the initial plant heatup phase from cold shutdown. In addition, they are intended to assist the plant in controlling the pressurizer pressure decrease that would occur during design basis transients that result in pressurizer outsurge events. These include the initial part of a 10% step-load increase transient, a 5% per minute plant unloading transient, or events resulting in a reactor trip.

The design basis pressurizer heater capacity to meet this requirement is 1 kW of heater capacity per cubic foot of pressurizer volume. The originally installed heater capacity was 1000 kW, 200 kW from the proportional heaters plus 800 kW from the backup heaters. The pressurizer internal volume is 1000 ft^3, therefore, the sizing basis of 1 kW/ft^3 was met (1000 kW/1000 ft^3 = 1 kW/ft^3). Subsequent to the initial pressurizer heater installation, for analysis purposes, the operating heater capacity was reduced to approximately 670 kW. Therefore, the acceptability of the available heater capacity of 670 kW was evaluated to ensure that the reduced capacity of 670 kW is sufficient to maintain the pressurizer pressure at its setpoint during steady-state operation and to minimize pressure excursions during design basis operational transients and a reactor trip transient.

Condenser Steam Dump Valves

The steam dump valves are designed to release steam to the condenser, which acts as an artificial heat sink during large (50%) load reductions and as a means of relieving the stored energy and decay heat after a reactor trip. One main requirement for their capacity is that they be able to relieve sufficient steam to prevent an automatic reactor trip following a large load reduction. The limiting reactor trip setpoints for a large load reduction transient are OTΔT and OPΔT reactor trip setpoints. These setpoints should not be challenged on a large load reduction transient. Other secondary requirements are to avoid steam generator safety valve lifting following either a large load reduction or a reactor trip from full power transient.

2.4.2.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Pressurizer PORVs

The pressurizer PORVs sizing analysis was performed at the PBNP Units 1 and 2 EPU operating conditions shown in LR Section 1.1, Nuclear Steam Supply System Parameters. The analysis was performed to envelope the window of operating conditions, full power T_{avg} of 558°F to 577°F and zero to 10% maximum steam generator tube plugging (SGTP) levels. With the NSSS power uprate to 1806 MWt (1800 MWt reactor power), the demand on the pressurizer PORVs would tend to increase. Therefore, the pressurizer PORVs sizing analysis was performed to ensure acceptability. The analysis was performed following the general guidelines and methodology presently in use by Westinghouse for similar uprate programs. This included the following key input parameters and assumptions listed below:

- The analyses are performed for full power T_{avg} values of 558°F (low T_{avg}) and 577°F (high T_{avg}), which bound all intermediate full power T_{avg}
- The transient is conservatively modeled as a 50% load reduction from 100.6% to 50% power, at the maximum turbine unloading of 200%/minute. 100% power corresponds to 1800 MWt reactor power
- The maximum steam pressure condition will provide the maximum pressurizer insurge, therefore, a 0% steam generator tube plugging (SGTP) level is used in the analysis
- The initial steam generator mass that corresponds to 90% of the nominal mass is conservatively assumed
- The plant is initially at nominal T_{avg} plus a 6.4°F uncertainty
- The initial pressurizer pressure is at nominal pressure of 2250 psia
- The initial pressurizer water level is at the nominal setpoint applicable to the T_{avg} operating conditions

- The pressurizer PORV installed capacity is 179,000-lb/hr saturated steam per valve at 2335 psig. There are a total of two valves.
- The NSSS control systems (rod, pressurizer level, steam generator level, and steam dump control systems) are assumed to be operational and functioning as designed. The steam generator level and pressurizer level control systems are not explicitly modeled; however, the steam generator mass and initial pressurizer water level is input at the nominal mass and/or assumed initial conditions. A conservative value of 24.2% and 19.6% of the rated steam flow for the steam dump capacity at high and low T_{avg} conditions respectively are used in the analysis.
- Conservatively, no credit is taken for pressurizer spray
- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) at conservative beginning of life (BOL) conditions were assumed

The acceptance criterion was that the installed pressurizer PORVs capacity should be sufficient to limit the peak pressurizer pressure to a value below the installed high pressurizer pressure reactor trip setpoint of 2365 psig during the design basis large load reduction with steam dump transient.

Pressurizer Spray Valves

The pressurizer spray valve sizing analysis was performed at the PBNP Units 1 and 2 EPU operating conditions as discussed in LR Section 1.1, Nuclear Steam Supply System Parameters. With the uprating, the demand on the pressurizer spray valves would tend to increase. Therefore, the pressurizer spray sizing analysis was performed to ensure acceptability at the uprated conditions. The analysis was performed following the general guidelines and methodology presently in use by Westinghouse for similar power uprate programs. This included the following key input parameters and assumptions listed below:

- The transient is conservatively modeled as a 10% step-load decrease from 100.6% to 90% power.
- The analyses are performed for full power T_{avg} values of 558°F (low T_{avg}) and 577°F (high T_{avg}), which bound all intermediate full power T_{avg}.
- The initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at the nominal setpoint applicable for the full power T_{avg} operating conditions.
- The installed pressurizer spray valves capacity was analyzed at 200 gpm per valve. There are two valves for a total capacity of 400 gpm.
- The NSSS control systems (rod, pressurizer level, pressurizer pressure, and steam generator level) are assumed to be operational and functioning as designed. The steam generator level and pressurizer level control systems are not explicitly modeled; however, the steam generator mass and initial pressurizer water level is input at the nominal mass and/or

assumed initial conditions. The steam dump is not actuated for a 10% step-load decrease transient; therefore, steam dump is not credited for this analysis.

- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) at conservative BOL conditions are assumed.

The acceptance criterion was that the total installed capacity (400-gpm total) of the pressurizer spray valves should be adequate to limit the peak pressurizer pressure to less than the pressurizer PORVs actuation setpoint of 2350 psia on a 10% step-load decrease transient.

Pressurizer Heaters

The pressurizer heater capacity sizing analysis was performed at PBNP Unit 1 and 2 EPU operating conditions discussed in LR Section 1.1, Nuclear Steam Supply System Parameters. For analysis purposes, the capacity of the heater is assumed to be less than the typical sizing criteria used for Westinghouse plants. The pressurizer heaters sizing evaluation was performed at EPU conditions. The evaluation was based on plant response to a reactor trip and a 10% step load increase transients. The analysis was performed following the general guidelines and methodology presently in use by Westinghouse for similar uprate programs. This included the following key input parameters and assumptions listed below:

- The analyses are performed for full power T_{avg} values of 558°F (low T_{avg}) and 577°F (high T_{avg}), which bound all intermediate full power T_{avg}.
- The initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at the nominal setpoint applicable for the full power T_{avg} operating conditions.
- The installed pressurizer heater capacity was analyzed at 67% of the initial design capacity of 1000 kW.
- The NSSS control systems (rod, pressurizer level, pressurizer pressure, steam generator level, and steam dump) are assumed to be operational and functioning as designed. The steam generator level and pressurizer level control systems are not explicitly modeled; however, the steam generator mass and initial pressurizer water level is input at the nominal mass and/or assumed initial conditions.
- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) at conservative BOL conditions are assumed.
- The step increase transient is conservatively modeled as a 10% step load increase from 89.4% to 100% power. Auxiliary feedwater is conservatively assumed actuated on steam generator low low level on the reactor trip transient.
- The reactor trip transient is conservatively analyzed from full power conditions.
- The steam dump is not actuated on a 10% step load increase; therefore, the steam dump is not credited for the 10% load increase transient.
- The steam generator safety valves are not modeled. Steam generator safety valves should not be challenged on a reactor trip transient.

The acceptance criteria for the installed heaters capacity is that the reduced capacity of 670 kW is sufficient to maintain the pressurizer pressure at its setpoint during steady-state operation and to minimize pressure excursions during design basis operational transients and a reactor trip transient. The reduced heater capacity is greater than 100 kW (TS LCO 3.4.9.b) and therefore heaters will continue to maintain the pressurizer pressure at its setpoint during steady-state operation.

Condenser Steam Dump Valves

The steam dump valves sizing analysis was performed at the PBNP Unit 1 and 2 EPU operating conditions as discussed in LR Section 1.1, Nuclear Steam Supply System Parameters. With the uprating, the demand on the steam dump valves would tend to increase. Therefore, the steam dump valves sizing analysis was performed to ensure acceptability at the uprated conditions. The analyses were performed following the general guidelines and methodology presently in use by Westinghouse for similar power uprate programs. This included the following key input parameters and assumptions listed below:

- The analyses are performed for full power T_{avg} values of 558°F (low T_{avg}) and 577°F (high T_{avg}), which bound all intermediate full power T_{avg}.
- The transient is conservatively modeled as a 50% load reduction from 100% to 50% power, at the maximum turbine unloading of 200%/minute. 100% power corresponds to 1800 MWt reactor power.
- The reactor trip transient is conservatively analyzed from full power conditions.
- The NSSS control systems (rod, pressurizer level, steam generator level, and steam dump control systems) are assumed to be operational and functioning as designed. The steam generator level and pressurizer level control systems are not explicitly modeled; however, the steam generator mass and initial pressurizer water level is input at the nominal mass and/or assumed initial conditions. A value of 23.2% and 18.7% of the rated steam flow for the steam dump capacity at high and low T_{avg} conditions respectively are used in the analysis.
- The steam generator safety valves are not modeled for both the large load reduction and reactor trip transients. Steam generator safety valves should not be challenged on these transients.
- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) at conservative BOL conditions are assumed.

The acceptance criterion for the steam dump valves was that the total installed capacity (23.2% and 18.7% of the rated steam flow for high and low T_{avg} conditions respectively) of the steam dump valves should be adequate not to challenge an automatic reactor trip on OTΔT and OPΔT reactor trip functions on a 50% load reduction with steam dump transient.

2.4.2.2.2.3 Description of Analyses and Evaluations

Pressurizer PORVs

A 50% load reduction with steam dump transient was analyzed using the LOFTRAN computer code. This computer code is a system-level program code that models the overall NSSS including the detailed modeling for control and protection systems. A LOFTRAN computer model was developed for PBNP Units 1 and 2. The 50% ramp load reduction transient is loop symmetric; the lumped-loop version of the LOFTRAN code was used for this analysis. The key input parameters and assumptions for the analysis are shown in Section 2.4.2.2.2.2, Pressure Control Component Sizing - Input Parameters, Assumptions, and Acceptance Criteria.

Pressurizer Spray Valves

A 10% step-load decrease from full-power transient was analyzed using the LOFTRAN computer code. A LOFTRAN computer model was developed for PBNP Units 1 and 2. The key input parameters and assumptions for the analysis are shown in Section 2.4.2.2.2.2, Pressure Control Component Sizing - Input Parameters, Assumptions, and Acceptance Criteria.

Pressurizer Heaters

The 10% step-load increase from 90% power and the reactor trip from full power transients were analyzed using the configured version of the LOFTRAN computer code. A LOFTRAN computer model was developed for PBNP Units 1 and 2. The method of analysis provides the means for evaluation of the adequacy of the reduced heater capacity. The key input parameters and assumptions for the analysis are shown in Section 2.4.2.2.2.2 Pressure Control Component Sizing - Input Parameters, Assumptions, and Acceptance Criteria.

Steam Dump Valves

A 50% load reduction with steam dump transient was analyzed using the configured version of the LOFTRAN computer code. A LOFTRAN computer model was developed for PBNP Units 1 and 2. The key input parameters and assumptions for the analysis are shown in Section 2.4.2.2.2.2, Pressure Control Component Sizing - Input Parameters, Assumptions, and Acceptance Criteria.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The components of the pressure control system were evaluated for aging effects requiring management for license renewal purposes. The adequacy of these components for license renewal is documented in the License Renewal SER, NUREG-1839 (Reference 1), Section 2.3.1.4, Pressurizer. The system components are subject to existing aging management programs which are described in the License Renewal SER Section 3.1, Reactor Coolant Systems. EPU activities are not adding any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operation of components of the pressurizer pressure control systems at EPU conditions are instrument setpoint changes that do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated which does not add any new or unevaluated aging effects that would necessitate a change to aging management programs or require new programs. Therefore, EPU activities associated with component sizing do not impact license renewal scope, aging effects, and aging management programs.

2.4.2.2.3 Results

Pressurizer PORVs

The maximum pressurizer pressure resulting from the analysis of 50% load reduction transient was 2352 psia, which is less than the high pressurizer pressure reactor trip setpoint of 2380 psia.

The pressurizer PORVs have sufficient relief capacity to avoid a reactor trip on high pressurizer pressure, overtemperature ΔT, and overpower ΔT for the design basis load reduction for PBNP Units 1 and 2 at EPU conditions. The PORVs were adequately sized for EPU conditions and no limitations to the plant operating conditions are required.

Pressurizer PORVs are not subjected to water-solid conditions during non-LOCA transients. LR Section 2.8.5.2.2, Loss of Non-Emergency AC Power to the Station Auxiliaries, and LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow show that water-solid conditions in the pressurizer do not occur under those transients. LR Section 2.8.5.0, Accident and Transient Analysis, addresses the ability of the RETRAN computer code that was used for these analyses to accurately determine the occurrence of water-solid conditions. LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems describes the ability of the pressurizer level control system to maintain the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during non-LOCA transient conditions.

Pressurizer Spray Valves

The results of a 10% step load decrease transient showed a maximum peak pressurizer pressure of 2316 psia, which is less than the pressurizer PORV actuation setpoint of 2350 psia.

Since the peak pressurizer pressure was less than the PORV actuation setpoint of 2350 psia, the total installed capacity of 400 gpm is adequate to avoid actuation of the pressurizer PORV during a 10% step-load decrease transient for the uprated conditions.

Pressurizer Heaters

For the 10% step load increase an (as shown in Table 2.4.2.2-1, Pressurizer Heaters Sizing Results – RPS and ESFAS Setpoint Evaluation - 10% Step Load Increase), the pressurizer pressure is maintained above the low pressurizer pressure reactor trip setpoint during a 10% step load increase transient. For the reactor trip transient (as shown in Table 2.4.2.2-2, Pressurizer Heaters Sizing Results - Reactor Trip), the pressurizer pressure is maintained above the low pressurizer pressure safety injection actuation setpoint and the pressurizer level is maintained above the low-low pressurizer level manual safety injection EOP action step.

For EPU, the reduced heater capacity remains sufficient to maintain the pressurizer pressure during design basis operational transients or events resulting in a reactor trip. The reduced heater capacity is greater than 100 kW, and therefore, the heaters will continue to maintain the pressurizer pressure at its setpoint during steady-state operation.

Table 2.4.2.2-1
Pressurizer Heaters Sizing Results – RPS and ESFAS Setpoint Evaluation - 10% Step Load Increase

Condition	Minimum Compensated Low Pressurizer Pressure (psia)	Pressurizer Low Pressure RPS Setpoint (psia)	Minimum Compensated Low Steam Line Pressure (psia)	Low Steam Line Pressure Setpoint (psia)
Low T_{avg}	2210	1940	559	545
High T_{avg}	2217		669	

Table 2.4.2.2-2
Pressurizer Heaters Sizing Results - Reactor Trip

Condition	Minimum Pressurizer Pressure (psia)	Minimum Pressurizer Level (% Span)	Pressurizer Low Pressure ESFAS Setpoint (psia)	Low-Low Manual SI setpoint (% span)
Low T_{avg}	2090	15.2	1750	10
High T_{avg}	1912	12.6		

Condenser Steam Dump Valves

The results showed a minimum margin to OTΔT and OPΔT trip setpoints were 4.8% and 11.1% respectively, with credit taken for maintaining a constant reference temperature of 576°F in the OTΔT and OPΔT reactor trip functions for all full T_{avg} between 577°F and 558°F.

2.4.2.2.4 Conclusions

PBNP has evaluated the effects of the proposed EPU on the functional design of the NSSS pressurizer pressure control systems. PBNP concludes that the evaluation adequately addresses the effects of the proposed EPU on these systems and that the other changes that are necessary to the reactor control systems to achieve the proposed EPU, are consistent with the pressure control component sizing design basis. PBNP further concludes that the pressure control components will continue to meet the PBNP current licensing basis requirements with respect to PBNP GDC 1, 11, 12, and 20. Therefore PBNP finds the proposed EPU acceptable with respect to the pressure control components.

2.4.2.2.5 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flood Protection

2.5.1.1.1 Regulatory Evaluation

PBNP conducted a review in the area of flood protection to ensure that safety-related structures, systems, and components (SSCs) are protected from flooding. The PBNP review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided.

The NRC's acceptance criteria for flood protection are based on General Design Criterion (GDC) 2.

Specific review criteria are contained in the Standard Review Plan (SRP) Section 3.4.1.

Current Licensing Basis

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers *of the Atomic Industrial Forum version of the proposed General Design Criterion.* (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-2 is as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

The plant internal flooding basis was initiated by a 1972 Atomic Energy Commission (AEC) generic communication request to determine whether a failure of non-category I (seismic) component could result in a flooding condition that could adversely affect equipment needed to get the plant to safe shutdown.

The consequences of a single failure of several non-category I systems in the turbine building, auxiliary building, and containment façade areas were evaluated. The degree of plant vulnerability to internal flooding and the design features credited to mitigate or forestall the adverse effects of the flooding are provided in NRC letter to Wisconsin Electric, Safety Evaluation Regarding the Potential for Flooding from Postulated Ruptures of Non-Category I (Seismic) Systems, dated November 20, 1975.

Additional information on internal plant flooding is provided in FSAR Appendix A.7, Plant Internal Flooding.

In addition to the evaluations described in the FSAR, PBNP's systems and components were evaluated for License Renewal. Systems and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

During plant license renewal evaluations, tanks and pipes, which were not already in-scope pursuant to 10 CFR 54.4(a)(1) or (a)(3) were evaluated to ensure they were not "non-safety equipment whose failure could affect a safety function" (Criterion (a)(2)). Components which met the inclusion criteria were evaluated within the system that contained them. Additionally, civil features whose function was to control, abate, or minimize the effects of flooding were identified and evaluated within the structure that contained them.

2.5.1.2 Technical Evaluation

Introduction

This section addresses protection from internal flooding outside containment from sources other than from high energy line breaks and cracks, including internal flooding due to failure of tanks, vessels, and process equipment. Internal flooding is also addressed in the following sections:

- Internal flooding due to high energy line breaks in the Primary Auxiliary Building (PAB) and Turbine Building is addressed in LR Section 2.5.1.3, Pipe Failures
- Submergence inside containment is addressed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- Internal flooding is also addressed in LR Section 2.5.1.1.2, Equipment and Floor Drains
- Protection of the control building from flooding due to a break/leakage in the Circulating Water System, and protection from internal flooding in the turbine building are addressed in LR Section 2.5.1.1.3, Circulating Water System (Related to Flooding)

PBNP's current licensing basis addresses design of systems and components important to safety to withstand the effects of natural phenomena (FSAR Table 1.3-1, General Design Criterion 2). Review guidance in Standard Review Plan Section 3.4.1 addresses (1) determination if liquid carrying systems could produce flooding, and an evaluation of measures taken to protect safety-related equipment and (2) review of the effects of potential flooding of systems and components due to postulated failure of non-seismic Category I and non-tornado protected tanks, vessels and other process equipment.

Impacts of EPU Related Plant Changes on Flooding

There are major physical modifications required to support operation of PBNP at the uprated power level as discussed in Section 1.0, Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report. Modifications that could potentially affect flooding outside containment include condensate and feedwater pump replacements, feedwater heater replacements, feedwater recirculation line size changes, high pressure turbine upgrades, and heater drain piping and valve modifications. The auxiliary feedwater (AFW) system is being modified, including installation of new motor-driven AFW pumps and associated piping. Condensate and feedwater piping will be modified to the extent necessary to allow fit up to nozzles associated with the new condensate and feedwater pumps and feedwater heaters. Evaluation of the effects of these plant modifications on internal flooding will be performed as part of the modification process.

Internal Flooding Due to Failure of Tanks, Vessels, and Process Equipment

The existing plant evaluations for flooding conditions in various plant locations have been reviewed to identify any changes related to the EPU. The current evaluations are summarized in FSAR Appendix A.7, Plant Internal Flooding. The consequences of non-category 1 system flooding hazards in the turbine building, auxiliary building and containment façade areas were evaluated as follows:

Circulating Water System (CWS) (Flooding)

The existing plant evaluation for flooding conditions in the turbine building postulates the loss of CWS integrity which results in filling the condenser pit. This could result in potential flooding in the auxiliary feedwater pump room, vital switchgear room and emergency diesel generator room. Design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, and related to the CWS have not been changed by the EPU, and therefore will not alter the original evaluation on flooding. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid, as discussed in LR Section 2.5.1.1.3, Circulating Water System (Related to Flooding).

Service Water System (SWS)

The existing plant evaluation for flooding conditions postulates the loss of SWS integrity which could result in potential flooding in the Control Room HVAC mechanical room and containment façade area. Design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, and related to the SWS have not been affected by the EPU, and therefore the original evaluation on flooding as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid.

Since the original evaluation was performed the service water piping in the Control Room HVAC mechanical room has been reclassified as Category I (Seismic) (FSAR Section 9.6.3, Service Water System, System Evaluation). As a result, there is no concern of non-seismic Category I piping failures in this room.

Condensate Storage Tank (CST) Piping System

The existing plant evaluation for flooding conditions postulates the loss of integrity of the piping connected to the CST, which could result in potential flooding in the non-vital switchgear room. The two CSTs have not been increased in size or capacity.

Currently, each CST has a single discharge line. These lines are connected together, forming a single header that supplies the motor-driven and turbine-driven auxiliary feedwater pumps. For EPU, as described in LR Section 2.5.4.5, Auxiliary Feedwater, the auxiliary feedwater system is being redesigned. As a result, after implementation of EPU the existing single suction header will supply only the turbine-driven AFW pumps. A new line is being connected into each CST discharge line, and these lines will be connected together to create a single suction header for the new motor-driven auxiliary feedwater pumps. Flooding issues for this new piping will be addressed during the modification process.

All other design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, and related to the CST piping system have not been changed by the EPU and therefore will not alter the original evaluation on flooding. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid.

Potable Water Piping System (PWS)

The existing plant evaluation for flooding conditions postulates the loss of integrity of the potable water piping inside the control room. Design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, and related to the PWS have not been changed by the EPU and therefore will not alter the original evaluation on flooding. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, is still valid.

Radwaste Monitor Tank (RMT)

The existing plant evaluation for flooding conditions postulates the failure of the Monitor Tank T-10D in motor control center (MCC) 2B-42 area. Design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, and related to the RMT have not been changed by the EPU and therefore will not alter the original evaluation on flooding. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid, as discussed in LR Section 2.5.6.2, Liquid Waste Management System.

Residual Heat Removal (RHR) Pumps

The existing plant evaluation for flooding conditions postulates flooding of the RHR pump cubicles. The RHR cubicle drain valves are maintained in the closed position. If an RHR pump seal failure occurred with the drain valves in the closed position, a RHR pump room high level alarm would be indicated in the control room. The cubicle could then be drained to the sump by opening the remotely operated drain valve. If flooding in EL-19' occurred due to a source other than a failed RHR pump seal, the fluid would collect in the center cubicle (cubicle between the Unit 1 and Unit 2 RHR pumps) and flow to the sump via the floor drains. The flow path to the RHR pump cubicle would remain isolated. Design features related to the RHR pump flood protection have not been changed by the EPU and therefore will not alter the original evaluation on flooding. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid.

Condensate and Feedwater

According to FSAR Appendix A.7, Plant Internal Flood, the postulated failure of the non-category I (seismic) condensate piping was evaluated. As discussed above in Impacts of EPU Related Plant Changes on Flooding, several modifications are being made to the condensate-feedwater system to support operation at EPU conditions. Impacts of these modifications on internal flooding will be performed as part of the modification process. Parts of the condensate and feedwater system piping are considered high energy lines. Flooding associated with high energy line breaks (HELB) and cracks is discussed in LR Section 2.5.1.3, Pipe Failures.

Fire Suppression System (FSS)

The EPU does not affect, change or modify the FSS. Therefore, the conclusion remains valid that actuation of the fire protection sprinklers will not flood the required safety-related equipment.

Systems in Containment Façade Areas

The existing plant flooding evaluation postulates flooding due to failure of non-category I (seismic) component cooling water (CCW) piping, steam generator blowdown (SGBD) piping, condensate piping, or a reactor makeup water tank (RMWT) in the containment façade areas. Design features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, related to these systems or a reactor makeup water tank have not been changed by the EPU. The original evaluation as stated in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, remains valid for these flood sources.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described in the FSAR, the barriers and equipment used to mitigate floods was evaluated for the PBNP License Renewal. The evaluations are documented in the License Renewal Safety Evaluation Report (SER) for the PBNP, (NUREG-1839), dated December 2005 (Reference 1). Section 2.4 of the License Renewal SER addresses aging management review of flood barriers in plant structures. As addressed in the License Renewal SER Sections 2.4.1 through 2.4.14, these barriers are evaluated within the systems that affect them. Since the EPU does not add any new or revised features that would affect the existing structures/components used to resist the effects of flooding, it does not affect the evaluation of these structures in the SER. Aging management of these structures and components is addressed in SER Sections 3.3 through 3.6.

Results

Previous evaluations have demonstrated that a failure of non-category I (seismic) components could not result in a flooding condition that would adversely affect equipment needed to bring the plant to safe shutdown. With respect to internal flooding, EPU does not affect the previously analyzed CWS, SWS, PWS, CCW, SGBD piping or fire suppression systems, the CST piping, the RMT, the RMWT, or the RHR pumps. Condensate feedwater and AFW piping is not impacted by EPU except potentially for the plant modifications discussed above. Evaluation of the effects of EPU related plant modifications on internal flooding will be performed as part of the modification process. Results of these evaluations will either demonstrate that the existing flood mitigating design features remain valid for operation at EPU conditions or additional flood mitigating design features will be installed.

2.5.1.3 Conclusions

PBNP has reviewed the potential changes in fluid volumes in tanks and vessels for the proposed EPU. PBNP concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet PBNP current licensing basis with respect to PBNP GDC 2 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to flood protection.

2.5.1.4 Reference

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.1.1.2 Equipment and Floor Drains

2.5.1.1.2.1 Regulatory Evaluation

The function of the Equipment and Floor Drains (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The PBNP review of the EFDS included the collection and disposal of liquid effluents outside containment. The review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations.

The NRC's acceptance criteria for the EFDS are based on:

- GDC 2, insofar as it requires the EFDS to be designed to withstand the effects of earthquakes
- GDC 4, insofar as it requires the EFDS to be designed to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures)

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.3.3.

PBNP Current Licensing Basis

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 2 and 4 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC-2)

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC-40)

Functions and features of the EFDS regarding internal flooding are addressed in the following FSAR sections:

- FSAR Section 6.2, Safety Injection System
- FSAR Section 6.5, Leakage Detection Systems
- FSAR Section 9.2, Residual Heat Removal System
- FSAR Section 9.3, Chemical and Volume Control System
- FSAR Section 9.11, Sampling System
- FSAR Section 11.1, Liquid Waste Management System
- FSAR Appendix A.7, Internal Flooding
- FSAR Appendix I.2 Section 2.4, Liquid Waste Processing Systems

In addition to the evaluations described in the FSAR, PBNP's systems and components were evaluated for License Renewal. Systems and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

During plant license renewal evaluations, tanks and pipes which were not already in-scope pursuant to 10 CFR 54.4(a)(1) or (a)(3) were evaluated to ensure they were not included in the category of "non-safety related systems, structures and components (SSCs) whose failure could prevent the accomplishment of a safety function" (Criterion (a)(2)). Components which met the inclusion criteria were evaluated within the system that contained them. Additionally, civil features whose function was to control, abate, or minimize the effects of flooding were identified and evaluated within the structure that contained them.

2.5.1.1.2.2 Technical Evaluation

This evaluation addresses functions of the EFDS, including routing and control of leakage, and prevention of backflow of water/contaminated fluids to areas of the plant containing safety-related equipment. Flooding caused by a high energy line break, such as a feedwater line rupture, including discussion of impact on drainage for EPU conditions, is addressed in LR Section 2.5.1.3, Pipe Failures.

As addressed in FSAR Appendix A.7, Plant Internal Flooding, Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, the EFDS serves to route leakage from equipment and specific rooms in order to provide proper control of leakage, prevent uncontrolled communication between areas, as necessary, and allow monitoring of leakage prior to disposition. Other than plant modifications, there have been no changes to the EFDS as a result of the EPU that would affect the flood mitigation features contained in Appendix A.7, Plant Internal Flooding, Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood. Evaluation of the effects of EPU related plant modifications on equipment and floor drains will be performed as part of the modification process.

As addressed in LR Section 2.5.1.1, Flood Protection, the EPU does not affect tank size or the volume of fluid in non-seismic tanks in plant areas where flooding from these tanks could affect safety-related components. Therefore, there is no additional leakage from these sources which could affect the EFDS.

The EPU does not affect the operating flow rates, pressures and component fluid capacities of the Station Service Water System (LR Section 2.5.4.2), the Reactor Auxiliary Cooling Water System (LR Section 2.5.4.3), the Fire Water System (LR Section 2.5.1.4, Fire Protection), the Circulating Water System (LR Section 2.5.8.1) or the Residual Heat Removal System (LR Section 2.8.4.4). Therefore, the EPU does not affect the capability of the floor drains systems to assist in the prevention of flooding due to line breaks in these systems in applicable areas or the prevention of backflow of fluids to areas with safety related equipment.

Impacts of EPU Related Plant Changes on Flooding

There are major physical modifications required to support operation of PBNP at the uprated power level as discussed in Section 1.0, Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report. Modifications that could potentially affect flooding outside containment include condensate and feedwater pump replacements, feedwater heater replacements, feedwater recirculation line size changes, high pressure turbine upgrades, and heater drain piping and valve modifications. The auxiliary feedwater (AFW) system is being modified, including installation of new motor-driven AFW pumps and suction piping. In addition the new motor-driven AFW pumps will be installed in the boric acid evaporator rooms which are not in use. Condensate and feedwater piping will be modified to the extent necessary to allow fit up to nozzles associated with the new condensate and feedwater pumps and feedwater heaters. Evaluation of the effects of these plant modifications on equipment and floor drains will be performed as part of the modification process.

The functions of the design features credited for mitigating plant internal flooding addressed in FSAR Appendix A.7, Plant Internal Flooding, Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, are not affected by the EPU. The modification process, will determine the need for new or enhanced flood protection in those areas where significant modifications will be installed. All EPU-required modifications evaluate the impact on flooding and result in acceptance of the condition or make the necessary changes to accommodate the new conditions, including adding mitigation methods for flood control. This includes the handling of additional expected leakage resulting from the modifications, the prevention of backflow of water to areas with safety-related equipment, and ensuring that contaminated fluids are not transferred to non-contaminated drainage systems. In those areas where EPU modifications will not be installed there are no required new or enhanced flood protection mitigation means required because system flows, tank capacities and piping are not being changed.

Results

As a result of the EPU, there are no plant changes to the mitigation features listed in FSAR Table A.7-1, List of Design Features Credited for Mitigating Plant Internal Flood, which result in additional leakage, in water backflow to areas with safety-related equipment or in contaminated fluid transferred to non-contaminated drainage systems. Plant modifications required to support operation at EPU conditions could potentially affect leakage from equipment, pipe and valves, and increase the amount of liquids entering the EFDS. Evaluation of the effects of EPU related plant modifications on equipment and floor drains will be performed as part of the modification process. Results of these evaluations will either demonstrate that the existing flood mitigating design features remain valid for operation at EPU conditions or additional flood mitigation controls will be installed.

Flooding caused by high energy line breaks (HELB) and cracks, including a discussion of impacts on drainage for EPU conditions, is addressed in LR Section 2.5.1.3, Pipe Failures.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described in the FSAR, the floor drains and equipment used to mitigate floods were evaluated for the PBNP License Renewal. The evaluations are documented in the License Renewal Safety Evaluation Report (SER) for the PBNP Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1).

Section 2.4 of the License Renewal SER addresses aging management review of flood barriers in plant structures. In the corresponding sections of this SER (2.4.1 – 2.4.14), these barriers are evaluated within the structure that contains them. Floor drains are evaluated in SER Section 2.3.3.11, Treated Water System. Since the EPU does not add any new structures/ components used to resist the effect of flooding, it does not affect the evaluation of these structures in the SER. Aging management of these components is addressed in SER Section 3.5.

2.5.1.1.2.3 Conclusions

PBNP assessed the effects of the proposed EPU on the EFDS and concludes that the assessment has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. PBNP concludes that the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes, (2) prevent the backflow of water to areas with safety-related equipment, and (3) ensure that contaminated fluids are not transferred to non-contaminated drainage systems. Based on this, PBNP concludes that the EFDS will continue to meet the requirements of PBNP GDCs 2 and 40 following the implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the EFDS

2.5.1.1.2.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.1.1.3 Circulating Water System (Related to Flooding)

2.5.1.1.3.1 Regulatory Evaluation

The Circulating Water System (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. This review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU.

The NRC's acceptance criteria for the CWS are based on:

- General Design Criteria (GDC) - 4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety related System, Structures and Components (SSCs)

Specific review criteria are contained in Standard Review Plan (SRP) Section 10.4.5.

PBNP Current Licensing Basis

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-4, as it relates to effects of flooding, is as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy Containment System Structure FSAR Section 5.1, FSAR 2007 Page 5.1-2 of 107 ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

The non-safety related CWS circulates water from Lake Michigan through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the lake through discharge flumes. The CWS is a non-seismic piping system whose primary function is to remove heat from the steam cycle via the main condensers. The CWS is described in FSAR Section 10.1, Steam and Power Conversion System.

A postulated loss of CWS integrity in the turbine building is described in FSAR Appendix A.7, Plant Internal Flooding. A failure of the expansion joint in the CWS would result in the filling of the condenser pit, with water continuing to rise above the 8 foot elevation of the turbine building. This could result in potential flooding in the auxiliary feedwater pump room, vital switchgear room and emergency diesel generator G-01/02 room. Flood protection measures in conjunction with existing plant design features provide a sufficient level of protection from flooding.

In addition to the licensing bases described in the FSAR, the CWS was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The above SER discusses the CWS in Section 2.3.3.12. Aging effects, and the programs credited with managing those effects, are described in Section 3.3.

2.5.1.1.3.2 Technical Evaluation

Protection of safety-related equipment from flooding due to a break or leakage in the CWS is discussed in FSAR Appendix A.7, Plant Internal Flooding. A failure of the expansion joint in the CWS would result in the filling of the condenser pit, with water continuing to rise above the 8 foot elevation of the turbine building. This could result in potential flooding in the auxiliary feedwater pump room, vital switchgear room and emergency diesel generator G-01/02 room. The auxiliary feedwater pump room does not contain the new motor-driven auxiliary feedwater pumps; they are located in another area not subject to CWS flooding. Flood protection measures in conjunction with existing plant design features provide a sufficient level of protection from flooding.

Evaluation of the impact of the EPU on analyses and design features related to internal flooding due to leakage or a break in the CWS is as follows: As discussed in LR Section 2.5.8.1, Circulating Water System, the CWS flow rate and operating pressures do not change at EPU conditions. There are no modifications to the CWS resulting from the EPU that affect flooding.

Results

The CWS flow rate and operating pressures do not change at EPU conditions. There are no modifications to the CWS resulting from the EPU that affect flooding. Accordingly, the analyses and design features related to internal flooding due to leakage or a break in the CWS for current plant conditions are unaffected by the EPU; protection of safety-related equipment continues to be provided.

2.5.1.1.3.3 Conclusions

PBNP has assessed the CWS from a flooding protection standpoint and concludes that this system was adequately evaluated. Since there are no modification to the CWS that affect flooding, PBNP concludes that there were no increased volumes of fluid leakage from the CWS piping or from a malfunction or failure of a CWS component that could potentially result in the failure of safety-related SSCs following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the CWS.

2.5.1.1.3.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

2.5.1.2.1.1 Regulatory Evaluation

The PBNP review concerns missiles that could result from in-plant component overspeed failures and high pressure system ruptures. PBNP's review of potential missile sources covered pressurized components and systems, and high-speed rotating equipment. The PBNP review was conducted to ensure that safety-related systems, structures, and components (SSC's) are adequately protected from internally generated missiles. In addition, for cases where safety-related SSC's are located in areas containing non-safety related SSC's, PBNP reviewed the non-safety related SSC's to ensure that their failure will not preclude the intended safety function of the safety-related SSC's. PBNP's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected.

The NRC's acceptance criteria for the protection of safety-related SSC's against the effects of internally generated missiles that may result from equipment failures are based on:

- GDC 4, insofar as SSC's important-to-safety are required to be protected against the effects of internally generated missiles that may result from equipment failures in order to maintain their essential safety functions.

Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion
(PBNP GDC).

The PBNP specific GDC for internally generated missiles is as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

Conformance to the requirements of PBNP GDC 40 ensuring that safety-related SSC's are adequately protected from internally generated missiles is primarily discussed in FSAR Section 4.1, Reactor Coolant System, Design Basis, FSAR Section 6.1, Engineered Safety Features Criteria, and FSAR Section 9.0, Auxiliary and Emergency Systems.

In addition to the evaluations described in the FSAR, PBNP's missile barrier components were evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage the aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the equipment and components credited with mitigating the effect of missiles is described in Section 2.4, Scoping and Screening Results - Containments, Structures, and Component Supports, and the programs credited with managing that equipment aging is described in Section 3.5.2, Aging Management of Containments, Structures, and Components Supports Staff Evaluation.

2.5.1.2.1.2 Technical Evaluation

Introduction

Safety-related SSCs at PBNP are protected from internally generated missiles from sources inside and outside of containment. These missiles are generated by failures in high energy systems and the overspeeding of rotating components.

The licensing requirement for protection of plant equipment against the dynamic effects associated with Loss of Coolant Accidents from postulated pipe ruptures is no longer applicable. This was an original design and licensing basis requirement, and the description has been retained in the FSAR because some missiles resulting from other postulated events (RCP flywheel failure, CRDM ejection, etc.) still remain. See Section 2.1.6, Leak-Before-Break.

Description of Analyses and Evaluations

Missiles that are generated internally to the reactor facility (inside or outside containment) may cause damage to SSCs that are necessary for the safe shutdown of the reactor or for accident mitigation or may cause damage to the SSCs whose failure could result in a significant release of radioactivity.

<u>Internally Generated Missiles Inside Containment</u>

FSAR Section 5.1.2.2, Mechanical Design Bases, identifies the types of postulated missiles inside containment. The potential sources of such missiles for which protection is provided are:

- Valve stems
- Valve bonnets
- Instrument thimbles
- Various types and sizes of nuts and bolts
- Complete control rod drive mechanisms or parts thereof
- Reactor coolant pump flywheels

Missile protection is provided to comply with the following criteria:

- The containment and liner are protected from loss of function due to damage by such missiles
- The engineered safeguards system and components required to maintain containment integrity are protected against loss of function due to damage by the missiles

During the detailed plant design, the missile protection necessary to meet the above criteria was developed and implemented using the following methods:

- Components of the reactor coolant system were examined to identify and to classify missiles according to size, shape, and kinetic energy for purposes of analyzing their effects
- Missile velocities were calculated considering both fluid and mechanical driving forces which can act during missile generation

The structural design of the missile shielding takes into account both static and impact loads and is based upon the state of the art of missile penetration protection.

From FSAR Section 5.1.2.7, Missile Protection, high pressure equipment, which is a potential source of missiles, is surrounded by barriers to prevent credible missiles from reaching the primary system, the containment liner, the secondary steam and feedwater piping, or the engineered safeguard system. Principal barriers against missiles are the reinforced concrete in the biological shield and the secondary shield walls surrounding the primary coolant loops. Supplemental barriers are provided to protect the liner plate from missiles which might be projected through openings in the secondary shield wall. In addition, a missile shield located above the reactor vessel head is designed to block missiles that could be generated by the control rod drive mechanisms. A reinforced concrete roof is provided above the pressurizer to prevent missiles from the pressurizer piping and valves from reaching the containment liner plate or other metal structures and systems.

FSAR Section 15.4.3, Fracture Mechanics Analysis, discusses the RCP flywheel analysis and the RCP casing analysis, including thermal aging factors (See LR Section 2.2.2.6, Reactor Coolant Pumps and Supports). The effect of EPU on the capacity of missile generation or protection equipment is low because the EPU does not require changes to the design pressure for the high energy systems inside containment. The Reactor Coolant System operating pressure does not increase (LR Section 1.1, Nuclear Steam Supply System Parameters). The Chemical Volume and Control System and other systems which are normally pressurized due to being connected to the Reactor Coolant System, will not be subject to any increase in operating pressure (LR Section 2.1.11, Chemical and Volume Control System). The Steam Generator secondary side operating pressure at full power decreases a nominal amount (LR Section 1.1, Nuclear Steam Supply System Parameters). This results in the Main Steam, Auxiliary Steam to the turbine-driven Auxiliary Feedwater pump, and Steam Generator Blowdown systems operating pressures decreasing a nominal amount. Feedwater system operating pressure inside containment will increase, but by less than about 1.5% and is bounded by current design temperature. See LR Section 2.5.5.4, Condensate and Feedwater

There are no EPU proposed modifications inside containment that will alter the layout of the high energy lines or the present arrangement of the missile barriers. EPU will require modification of the moisture dryer components internal to the Steam Generator; however, this will not alter the Steam Generator pressure boundary.

FSAR Section 4.2, RCS System Design and Operation, Components, Reactor Coolant Pumps, discusses why the reactor coolant pump flywheels are not considered credible missile sources. It also states why other reactor coolant pump parts would not be postulated missile sources since they would be contained by either the motor stator or pump casing. EPU does not require physical changes to the reactor coolant pumps nor does it change their motor and pump rotating speeds (LR Section 2.2.2.6, Reactor Coolant Pumps and Supports).

There are no proposed changes to ventilation systems inside containment (LR Section 2.7.7, Other Ventilation Systems (Containment)). During accident conditions, the existing design of the containment fan coils is adequate for containment heat removal (LR Section 2.6.5, Containment Heat Removal). As such, there is no change to the rotating speed of ventilation fans.

The EPU does not affect the system pressures for the systems inside containment such that additional missiles could be generated (LR Section 1.1, Nuclear Steam Supply System Parameters). The EPU will not result in any system configuration changes (e.g., piping rerouting and new components) inside containment that would impact any existing missile barrier considerations. As such, the existing missile protection measures inside containment remain effective for EPU conditions.

Internally Generated Missiles Outside Containment

Internally generated missile sources are postulated from high energy lines and from high speed rotating equipment. Refer to LR Section 2.5.1.2.2, Turbine Generator, for evaluations of potential turbine missiles.

As stated in FSAR Section 6.1.1, Engineered Safety Features Criteria, protection of Engineered Safety Features required for safe shutdown is provided by provisions which are taken in the design to prevent generation of missiles and protection provided by the layout of plant equipment or by missile barriers.

High energy lines outside containment include the Main Steam (MS), CVCS letdown, Steam Generator Blowdown, feedwater, parts of the heater drains, extraction steam to the 5th feedwater heater, and part of the condensate system.

MS (including MS to the turbine-driven AFW pumps), CVCS letdown, Steam Generator Blowdown, and condensate high energy lines will not see any pressure increase due to EPU. EPU will increase the operating pressure of the feedwater lines from the turbine building to the containment, but only by less than 1.5% and is bounded by current design temperature. See LR Section 2.5.5.4, Condensate and Feedwater. Per FSAR Section A.2.8, Main Feedwater Piping, there are no safeguards equipment in the area traversed by the feedwater piping. The other lines will see a pressure increase but they are totally within the non-safety related turbine building.

Physical EPU modifications are required in areas outside the containment. The modifications pertinent to high energy lines outside containment are listed below. These changes are being made through the design modification process which will verify that these changes do not create an unacceptable missile hazard to Engineered Safety Features.

- The systems in the turbine building will have physical modifications including upgraded feedwater heaters and higher capacity condensate and feedwater pumps. The upgraded pumps will still use electrical motors as the prime movers. Although some minor piping changes are anticipated, the replacement equipment will remain in the same location and no significant layout changes are expected. In addition, the locations of these components are isolated from Engineering Safeguard Features. The modification process will confirm that the changes in the turbine building do not create a missile hazard to Engineered Safety Features equipment.
- A new feedwater isolation valve will be located just upstream of each of the two outboard feedwater containment isolation check valves. Since this is a new component, the design change process will verify that it does not create a missile hazard to other Engineered Safety Features and that it is not a target from postulated missiles in accordance with the CLB.
- The Auxiliary Feedwater (AFW) system is being redesigned to support operation at EPU conditions. LR Section 2.5.4.5, Auxiliary Feedwater, discusses the required physical modifications, including the addition of new motor-driven pumps and their associated lines at the 8' elevation in the primary auxiliary building. As discussed in LR Section 2.5.4.5, Auxiliary Feedwater, the main steam line to the TDAFW pump, which is the only AFW high energy line, is not being changed. The design change process will verify that adequate protection from postulated missiles will be provided for the new AFW equipment.

EPU does not require changes to ventilation systems outside containment. As such, EPU does not require physical modifications to any ventilation fans (refer to LR Sections 2.7.1, Control Room Habitability, through 2.7.6, Engineered Safety Feature Ventilation System). LR Section 2.7.1, Control Room Habitability, addresses the EPU impact on the Control Room Habitability, including the modifications to the flow paths required as a result of proposed LAR 241, Alternative Source Term (ML083450683).

The change in EDG loading, due to the AFW System modifications described in LR Section 2.5.4.5, Auxiliary Feedwater, does not alter the missile protection for the EDGs from turbine missiles or other missiles generated outside the diesel rooms.

The EPU does not adversely impact the system pressures for the systems outside containment that could generate missiles. The EPU will require a number of physical modifications outside the containment, but none is anticipated to adversely impact the present design basis for missile generation and protection. Moreover, the modification process will ensure that these physical changes do not adversely affect the existing missile protection measures outside containment.

Evaluation of the Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described in the FSAR, PBNP's missile barrier components were evaluated for License Renewal. Systems and system component materials of construction, operating history, and programs used to manage the aging effects are documented in Sections 3 and 4 of the License Renewal Safety Evaluation Report (SER) for the Point Beach Nuclear Plant Units 1 and 2, NUREG-1839, published December 2005 (Reference 1).

With respect to the above SER, the equipment and components credited with mitigating the effect of missiles are described in Section 2.4, Scoping and Screening Results - Containments, Structures, and Component Supports, and the programs credited with managing that equipment's aging are described in Section 3.5, Aging Management of Containments, Structures, and Component Supports. Operating at EPU does not add any new or previously unevaluated materials to missile barrier components. Thus, no new aging effects requiring management are identified as a result of EPU.

Results

The EPU does not adversely impact the pressures in the systems inside containment that could generate missiles, nor will it change the operating conditions of high speed rotating equipment such as the Reactor Coolant Pumps. The existing missile protection measures inside containment remain effective for EPU conditions.

For plant areas outside containment containing safety-related SSCs, the EPU will not result in changes to existing missile sources. The sole pressure increase to high energy lines outside the turbine building is to the feedwater lines from the turbine building to the containment; however, this change is small, less than about 1.5%, and is bounded by design temperature (See LR Section 2.5.5.4, Condensate and Feedwater). When new components are added that could become new potential missile sources, verification of the potential missile sources takes place and appropriate barriers are added as part of the design modification process. The EPU does not result in any system configuration changes that could impact any existing missile barriers.

2.5.1.2.1.3 Conclusions

PBNP has addressed the effects of changes in system pressures and configurations that are required for the proposed EPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles following implementation of the proposed EPU and will continue to meet the requirements of PBNP GDC-40. Therefore, PBNP finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.1.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.1.2.2 Turbine Generator

2.5.1.2.2.1 Regulatory Evaluation

The turbine control system, steam inlet stop and control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. PBNP staff's review of the turbine generator focused on the effects of the proposed EPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely.

The NRC's acceptance criteria for the turbine generator are based on:

- General Design Criterion (GDC)–4, insofar as it relates to the protection of SCCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles.

Specific review criteria are contained in SRP Section 10.2.

PBNP Current Licensing Basis

As noted in PBNP updated Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-4 is as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

FSAR Section 14.1.12, Likelihood of a Turbine Generator Unit Overspeed, provides a summary of the licensing activities related to protecting the plant against the possible occurrence of a turbine generator missile due to overspeed of the turbine generator. Due to the present advanced state of the art of rotor forging and inspection techniques which provides for defect-free turbine rotors, along with the redundancy and reliability of the turbine control protection system and of the steam system, the probability of occurrence of a unit over-speeding above the design value is very remote. Measures to ensure availability and appropriate testing are contained in Technical Requirements Manual (TRM) 3.7.6, Turbine Overspeed Protection (Reference 2).

Turbine Generator overspeed is also discussed in FSAR Sections 9.4.3, System Evaluation, and 10.1, Steam and Power Conversion.

In addition to the evaluations described in the FSAR, PBNP systems were evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report (SER) Related to the License Renewal of the PBNP Units 1 and 2 (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the Turbine Generator is not within the scope of License Renewal. However, the programs used to manage the aging effects associated with the steam and power conversion systems are discussed in Section 3.4 for the above SER.

2.5.1.2.2.2 Technical Evaluation

Introduction

High-pressure steam enters the turbine through two turbine stop valves and four governing valves. One turbine stop and two governing valves form a single assembly which is anchored above the turbine room floor line. An electro-hydraulic (EH) servo-actuator controls each turbine stop valve so it is either in the wide open or closed position. The control signal for this servo-actuator comes from the mechanical hydraulic overspeed trip portion of the EH control system. The major function of these turbine stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the protective devices function. The governing valves are positioned by a similar EH servo-actuator acting in response to an electrical signal from the main governor portion of the EH control system. Upon loss of load, the auxiliary governor portion of the EH control will act to close the governor valves rapidly.

As depicted in FSAR Section 10.1, Steam and Power Conversion, the EH turbine control system combines a solid state electronic controller with a high pressure fire resistant fluid supply system which is independent of the lubricating oil. The design features and response characteristics of the system increase the reliability and availability of the power plant.

The EH control system includes the following features:

1. Governor valve controller
2. Load limit controller
3. Auxiliary governor
4. Speed controller
5. Load controller
6. Operators panel on the main control board
7. High pressure hydraulic fluid pumping unit

8. Turbine protective devices, including function limit trips, and extraction line non-return valves closing signal.

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft, which is held in position by a spring until the speed reaches approximately 105% of rated speed. Its centrifugal force then overcomes the spring and the weight strikes a trigger which trips the overspeed trip valves and causes the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure, closing the turbine stop and governing control valves. An air pilot valve is used to close the nonreturn valves in the high pressure (HP) turbine extraction lines and in the moisture separator drain lines.

The auxiliary governor provides overspeed protection via the overspeed protection circuitry (OPC) and the EH high pressure fluid system. It will close the governor valves by energizing the OPC solenoid valves if the turbine speed, as sensed from the auxiliary speed tachometer, exceeds 103% of rated speed. By means of the load drop anticipator (LDA), it will shut the governor valves by energizing the OPC solenoid valves following a complete load separation. The load drop anticipator measures the mismatch (~30%) between the reheat pressure and the megawatt signals provided the reheat pressure is above a preset value.

The independent overspeed protection system (IOPS) monitors speed electronically and causes a trip signal to be generated should turbine speed exceed 104%. There are 3 identical independent speed channels. The signal for each channel originates from a magnetic pickup mounted adjacent to the shaft turning gear. AC pulses, whose frequency is dependent on turning gear RPM, are generated by the magnetic pickup as the teeth of the turning gear pass. These pulses are transmitted to the speed circuit. The speed circuit generates a fixed-width filtered pulse which is proportional to turbine speed. For reliability, trip signals are generated only when any 2 of 3 channels sense overspeed. Also built into the speed measuring circuitry is a failure detection system which detects failure of the speed pickup, speed wiring or speed amplifier. Failure detection in 2 of 3 speed channels will also trip the turbine. The overspeed trip signals and failure detection signals operate 2 independent relay trains which in turn operate turbine-mounted solenoid valve fluid dump systems, closing the stop and governor valves. Thus failure of one of the 2 relay trains to operate will not prevent this device from tripping the turbine. Test circuitry is provided to test operation of all components without actually tripping the turbine.

To prevent turbine overspeed from backflow of flashed condensate from the feedwater heaters after a turbine trip, bleeder trip valves are provided in the extraction lines to heaters Nos. 4 and 5 and in the moisture separator drain lines. The bleeder trip valves are air operated valves that are closed automatically upon a signal from the turbine trip circuit.

In the event of a loss of electrical load on the turbine generator unit, the restraining torque on the turbine rotor unit is lost. However, the steam energy entrapped in the turbine unit may cause the rotor to accelerate, potentially causing an overspeed condition. The crossover steam dump system, developed to mitigate such a condition, is located on the crossover piping between the moisture separator reheaters and the Low Pressure (LP) turbines and is described in FSAR Section 10.1, Steam and Power Conversion. The purpose of the system is to provide a means of energy removal from the turbine in the event of a unit trip and is designed to assure that the maximum design overspeed of 132% will not be exceeded. The system consists of four air pilot-operated dump valves located in the HVAC equipment room. Discharge from these dump valves is carried to the atmosphere through individual vent stacks. The system is armed at 430 MWe equivalent load and actuated upon turbine trip at 104% of design speed. The dump valves are reseated by applying reseat steam pressure following a time delay after the required blowdown. Service air may be used as an alternative administrative pressure source to assist in closing a stuck open dump valve. Any three of the four dump valves will provide the design capacity to prevent exceeding the turbine maximum overspeed.

For proper EPU operation, modifications are required to the high pressure (HP) turbines to pass the additional volumetric steam flow. The turbine control valves and inlet piping will be modified to accommodate the increase in steam flow, increased pressure drop from the steam generators and resultant higher first stage pressure. The low pressure (LP) turbines will not be modified as they are capable of passing the higher volumetric flow rate.

The HP turbine rotor will be replaced with an all-reaction design rotor. The new rotor will accommodate EPU pressure and flow conditions. The major operating change associated with this design is that the turbine will be operated in full arc steam admission mode at all operating conditions. Steam is admitted to the HP turbine through four separate governor valves, two per steam chest. Full arc operation refers to the mode of control of the governor valves. In full arc admission, all four governor valves receive the same demand signal (i.e., each governor valve is open the same amount at any load).

This modification will require changes to the HP turbine flow path, including inlet piping (increase to 16"), control valves (modify to high lift design), turbine blades and rotor, and controls. Several setpoint changes and minor piping changes to accommodate the control valve modifications are also required to the Electro-Hydraulic Control system to support the EPU.

Description of Analyses and Evaluations

The EPU increases the unit maximum power and the amount of entrapped energy. This may result in an increase in expected peak overspeed. An analysis was performed to demonstrate that the increase in power and entrapped steam energy at EPU conditions will not cause the turbine rotor to overspeed beyond the current design limit. The following considerations were applied to this overspeed analysis:

- The normal operating turbine generator rotor "running" speed of 1800 rpm will not change as the result of EPU.
- The auxiliary governor provides overspeed protection via the overspeed protection circuitry (OPC) and the EH high pressure fluid system. It will close the governor valves by energizing the OPC solenoid valves if the turbine speed, as sensed from the auxiliary speed tachometer, exceeds 103% of rated speed. This will be changed for EPU.
- The electronic overspeed trip (Independent Overspeed Protection System or IOPS), should trip the turbine at electronic overspeed trip setting. The analysis shows that IOPS trip at the uprated conditions without the crossover steam dump system active yields an overspeed that is above the 132% design overspeed; therefore, steam dump system arming will be required but no change to IOPS is required. However, the crossover steam dump valve arming setpoint will be changed due to the increase in rated turbine power.

- The last line of defense is the mechanical overspeed trip mechanism. It consists of an eccentric weight mounted in the end of the turbine shaft, which is held in position by a spring until the speed reaches approximately 105% of rated speed. This will not change as a result of EPU.
- The Turbine design overspeed limit of 132% of design speed will not change as a result of EPU.
- The operability and reliability of the turbine overspeed protection system is verified via the performance of routine turbine control valve testing. At each turbine overhaul and each refueling outage, the turbine speed is increased to the overspeed trip setpoint to verify proper operation of the valves. When the turbine is brought up to speed, valves are tested as part of the power ascension. Therefore, the continued operability and reliability provided via valve performance testing at EPU conditions will be maintained (refer to LR Section 2.12.1, Approach to EPU Power Level and Test Plan).

The overspeed analysis described above is predicated on the fact that the non-return valves between the heaters and the steam turbine will close as required when the unit is tripped. The effects of the heaters that do not have non-return valves are already accounted for in the analysis since the MW vs. overspeed relationship that was used as described previously is based on actual test data, and any effects on the pressure decay were included in the original transient analysis. With respect to the other heaters (heater Nos. 4 and 5), the predominant effect on overspeed will be due to the water in the heater flashing to steam, and expanding through the turbine. Based on an evaluation performed, both the IOPS and mechanical trips result in overspeed less than the 132% design value.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The Turbine Generator is not within the scope of License Renewal. However, the programs used to manage the aging effect associated with the steam and power conversion systems are discussed in License Renewal SER Section 3.4. The changes associated with operating the turbine generator at EPU conditions do not add any new or previously unevaluated materials or components to the system. In addition, changes being made to the high pressure turbine assembly do not introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. The turbine generator overspeed control system will continue to operate within its current design limit. Therefore, no new aging effects requiring management are identified.

Results

Continued compliance with the turbine generator overspeed protection requirements was demonstrated at the EPU conditions with only a change to the OPC setpoint and a change to the crossover steam dump valve arming setpoint due to the increase in rated turbine power. The EPU overspeed analyses results are as follows.

Missile Analysis

Based on evaluation of the LP rotor blade path steam temperatures for the baseline and uprated operating conditions in comparison to the original and/or maximum for the Siemens fleet, the conclusions of the existing missile analysis remain unchanged. Steam temperatures and resultant rotor disc temperatures remain at or below their original bounding assumptions. Therefore, the existing missile analysis submitted to the Nuclear Regulatory Commission (NRC), Report WSTG-4-P, Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Rotors, October 1984, Westinghouse (now Siemens) Proprietary, remains valid for the proposed EPU.

Overspeed Analysis

Based on overspeed analysis, the Independent Overspeed Protection System (IOPS) trip at the uprated conditions without the crossover steam dump system active yields an overspeed that is above the 132% design overspeed; therefore, crossover steam dump system arming will be required. With the crossover steam dump system armed, both the IOPS and the mechanical trip result in overspeeds that are below the design overspeed of 132% with 3 out of 4 crossover steam dump valves functioning. Therefore, no change to the IOPS or mechanical trip setting is required.

2.5.1.2.2.3 Conclusions

PBNP has reviewed the assessment of the effects of the proposed EPU on the turbine generator and concludes that PBNP has adequately accounted for the effects of changes in plant conditions on turbine overspeed. PBNP concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the PBNP current licensing basis requirements of PBNP GDC 40. Therefore, PBNP finds the proposed EPU acceptable with respect to the turbine generator.

2.5.1.2.2.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 Technical Requirements Manual (TRM) 3.7.6, Turbine Overspeed Protection, November 22, 2006

2.5.1.3 Pipe Failures

2.5.1.3.1 Regulatory Evaluation

PBNP conducted a review of the plant design for protection from piping failures outside containment to ensure that:

- Such failures would not cause the loss of needed functions of safety-related systems
- The plant could be safely shut down in the event of such failures

The PBNP review of pipe failures included high energy fluid system piping located outside containment. The review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post accident operations where the consequences are not bounded by previous analyses.

The NRC's acceptance criteria for pipe failures are based on:

- General Design Criterion (GDC) 4, which requires, in part, that structures, systems and components (SSCs) important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids.

Specific review criteria are contained in Standard Review Plan (SRP) 3.6.1, Plant Design for Protection against postulated Piping failures in Fluid Systems outside Containment.

PBNP Current Licensing Basis

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for pipe failures is as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

FSAR Appendix A.2, High Energy Pipe failure Outside Containment, discusses high energy pipe breaks outside containment. Systems which qualify for analysis are:

- Main steam piping
- Turbine bypass to condenser
- Auxiliary steam supply to auxiliary feedwater pump turbine
- Auxiliary steam supply to waste disposal equipment
- Steam generator blowdown piping
- Main feedwater piping
- Sample lines

- Steam generator blowdown heat exchanger condensate return.

In addition to the evaluations described in the FSAR, the protective barriers and license renewal boundaries associated with high energy line breaks were evaluated for License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 5)

Sections 2.3.4, Steam and Power Conversion Systems, 2.4.2, Control Building Structure, and 2.4.6, Primary Auxiliary Building Structure, of the License Renewal SER addresses aging management review of high energy line break barriers in plant structures. As addressed in the License Renewal SER, the license renewal evaluation boundaries for the main steam and main feedwater systems were defined consistent with the high energy line break analysis as defined in the FSAR. Within the SER, the structures and structural components used to resist the effects of pipe breaks are evaluated within the structure that contains them. Aging management of these components is described in Section 4 of the SER.

2.5.1.3.2 Technical Evaluation

Introduction

A systematic and complete approach for the development of the High Energy Line Break (HELB) analysis and its use in establishing the environmental parameters required as input to the EQ and other programs was used. Each of the steps in the analysis resulted in report(s) or calculation(s) documenting the inputs, assumptions, methodology and results. These design output documents form the basis of the PBNP HELB program. Experience has shown that this set of documented bases will provide for the establishment and improvement of design margins for plant components.

The High Energy Line Break (HELB) analysis identifies high energy piping system lines subject to failure and the plant safety-related equipment potentially impacted by piping failures, determines the environmental effects resulting from the piping failures, and identifies the protection measures required to mitigate the effects of the piping failures. The environmental conditions resulting from this analysis are provided as input into the environmental qualification program. Refer to LR Section 2.3.1, Environmental Qualification of Electrical Equipment for the discussion of EPU impact and to LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects for the discussion on postulating pipe break locations.

The HELB program was reconstituted to ensure documentation existed to demonstrate compliance with all related prior licensing commitments and to reconstitute missing documentation. A new licensing basis is established which requires NRC approval prior to implementation. This new licensing basis is described in this LR section and in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects.

The evaluation of pipe breaks outside containment considered the zones within the plant which contain systems required for safe shutdown and/or systems required to mitigate the effects of postulated pipe breaks.

New calculations evaluated the available pipe stress analyses by implementing the guidance contained in GL 87-11 and its attached MEB 3-1. The combined stress values in the stress reports that include seismic were revised to incorporate ASME Section III, 1986 Edition requirements in lieu of stress intensification factors. The resultant stresses were then compared to the break and crack stress thresholds defined by the equations in MEB 3-1. For those high energy systems that did not have a dynamic seismic analysis, a break was postulated at the weld to every fitting, valve and welded attachment. Rather than determine all of these locations, a break was postulated in every compartment the piping run traverses. In addition, a crack was postulated to occur any where along the run of pipe at the most adverse location.

Pipe failures inside containment are addressed in LR Section 2.6.1, Primary Containment Functional Design, and LR Section 2.6.2, Subcompartment Analyses.

Description of Analyses and Evaluations

The impact of the EPU on pipe failures and corresponding pipe whip, jet impingement, environmental conditions, and flooding was evaluated. The evaluation considers the events that are bounding for each system containing or affecting essential equipment, that is, equipment performing safety related functions required to operate for mitigation of the pipe failures including unit shutdown.

Licensing basis changes are identified below:

High Energy Line Break

The PBNP high energy line break (HELB) outside containment program is reconstituted to ensure documentation exists to demonstrate compliance with all related prior licensing commitments and to reconstitute missing documentation. A new licensing basis is established which requires NRC approval prior to implementation.

- The guidance of GL 87-11 (Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987) is used for the evaluation of pipe rupture location and dynamic effects.
- The stress thresholds for identifying break and crack locations from Branch Technical Position MEB 3-1 (Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2 dated June 1987, (Reference 6)) are also adopted.
- The determination of stress values for rupture postulation evaluations are calculated using ASME B&PV Code Section III, 1986 edition requirements in lieu of stress intensification factors.
- ASME Code Cases N-318-5 (Procedure for Evaluation of the design of Rectangular Cross Section Attachments on Class 2 & 3 Piping, dated 4/28/94) and N-392-1 (Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 2 & 3 Piping, dated 12/11/89) are used to calculate the local stresses due to shear lugs and hollow circular attachments, respectively.
- The method for calculating local stresses at the elbow lugs is in accordance with 1979 PVP Spring Conference Paper 79-PVP-51 (Stresses in Elbows Created by Supported Lug Load, T.K. Emera and E.C. Rossow).

- Requirement of postulating a single open crack at the location most damaging to those essential structures and systems is in accordance with NRC Information Notice IN 2000-20, Potential Loss of Redundant Safety-Related Equipment.

High Energy Lines

The definition of a High Energy (HE) line, including the operating temperature and the design pressure is unchanged for EPU. Table 2.5.1.3-1 identifies the HE lines and the change in operating temperature conditions and the changes in design pressure at EPU. The maximum operating pressure increased above the system design pressure for the extraction steam line from the HP turbine to the #5 feedwater heater and the heater drain line from the 5th to the 4th feedwater heaters due to EPU. In both cases, the calculated wall thickness of the existing piping at the new design values were found to be acceptable for operation at EPU conditions. Changes in conditions due to EPU do not require the recharacterization of any lines from low energy to high energy.

Summary of EPU Impact on Systems

All systems or portions thereof, outside of containment that meet the definition of high energy and size criteria have been evaluated as described below. The EPU operating conditions do not add any new piping segments to the system selection. The attached Table 2.5.1.3-1, List of High Energy Lines and the Change in Operating Conditions, identifies those systems, or portions thereof, which traverse the Facade, Primary Auxiliary Building and Turbine Building and meet the definition of high energy. FSAR Appendix A.2, High Energy Pipe Failure Outside Containment, identified high energy systems as main steam to various services, feedwater, steam generator blowdown and sampling. The appendix does not address CVCS letdown or other systems in the Turbine Hall. All these HE systems are included in the reconstitution and in the EPU evaluation. The discussion of the EPU requirements for each HE system follows:

- Main Steam System (MS) (including Steam Supply to auxiliary feedwater pump)

  The analysis shows that the MS system no-load operating pressure and temperature show no increase and remain unchanged at 1005 psig and 547°F, respectively. Therefore the MS system's analysis of record remains valid as it relates to stress tables to determine GL-87-11 (Reference 4) break and or crack locations. The 3" Steam Supply lines from the 30" Main Steam Headers to the Auxiliary Feedwater Pump have been evaluated for break and crack locations. The combined stresses for all piping are well below the intermediate Large Break Threshold Limit. Therefore, no intermediate large breaks need to be postulated for the 3" line.

- Extraction Steam System

  A dynamic seismic stress analysis is not available for the extraction steam system in the Turbine Hall. Therefore, a break must be considered at each weld to a fitting, valve or welded attachment in accordance with the MEB 3-1 (Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in every compartment that the lines traverse. A single crack must also be postulated at the most adverse location. However, the effects of cracks would be bounded by the postulated break.

- Condensate

  The condensate pumps and associated motors will be replaced with higher rated flow pumps and total developed head to accommodate the increases required in feedwater flow and pressure drops.

  A dynamic seismic stress analysis is not available for the condensate system, including the return from the steam generator blowdown heat exchanger located in the applicable unit's Facade. Therefore, a break must be considered at each weld to a fitting, valve or welded attachment in accordance with the Branch Technical Position (Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in every compartment that the lines traverse. A single crack must also be postulated at the most adverse location. However, the effect of a crack would be bounded by the postulated break.

- Feedwater System

  The main feedwater pumps and associated motors will be replaced with pumps with higher rated flow and total developed head to accommodate the increases required in feedwater flow and pressure drops. The condensate pumps are also being replaced for higher flow rating. The FW regulating valves will be modified with new valve trim with a higher flow coefficient (Cv). All feedwater heaters will be replaced. To minimize mass and energy releases inside Containment following a HELB new Feedwater Isolation Valves are being installed in the main feedwater lines. Several pipe supports on the main feedwater piping will be modified to accommodate the modified equipment and the increased piping loads at EPU conditions.

  A dynamic stress analysis is available for feedwater piping from the Primary Auxiliary Building (PAB)/Turbine Hall interface to the containment penetrations. A dynamic seismic stress analysis is not available for the non-seismic portion of the feedwater piping system from the pump discharge nozzles to the PAB/Turbine Hall interface. Therefore, in the Turbine Hall, a break must be considered at each weld to a fitting, valve or welded attachment in accordance with the Branch Technical Position (Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in each compartment that the lines traverse.

  In the seismic portion of the piping these calculations and associated stress information were reviewed to determine which nodes, if any, exceed the break or crack criteria. There were no intermediate locations that exceeded the break criteria. However, there is one location that exceeds the crack criteria in the South Service Building.

  In the non-seismic portion of the piping, a break must be postulated at the weld to every valve, fitting and welded attachment. The piping between the feedwater pump discharges and the start of the dynamic analysis is routed entirely in the Turbine Hall.

- Steam Generator Blowdown System

No dynamic stress analysis is available for the steam generator blowdown line from the containment penetration to the blowdown heat exchanger and flash tank nozzle located in the Facade. Therefore, the terminal ends at the containment penetration, the heat exchanger and flash tank nozzles are considered break locations. In addition, breaks must be postulated at each weld to a fitting, valve or welded attachment in accordance with the Branch Technical Position (Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in each compartment that the lines traverse (the piping system is limited to the applicable unit's Facade). A single crack must also be postulated at the most adverse location. However, the effect of the crack would be bounded by the postulated break.

- Chemical and Volume Control System Charging and Letdown Lines

  No dynamic stress analysis is available for the letdown line from the containment penetration to the non-regenerative heat exchanger nozzle. Therefore, the terminal ends at the containment penetration and the heat exchanger are considered break locations. In addition, breaks must be postulated at each weld to a fitting, valve or welded attachment in accordance with the Branch Technical Position (Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in each compartment that the lines traverse. A single crack must also be postulated at the most adverse location. However, the effect of the crack would be bounded by the postulated break.

  By inspection of Table 2.5.1.3-1, the Chemical and Volume Control System (CVCS) operating parameters were not changed by EPU. However, the CVCS letdown was not addressed in the FSAR. Due to the pipe routing there would be numerous postulated breaks in each of three compartments each line traverses in the pipeway and the Primary Auxiliary Building for both PBNP Units 1 and 2. However, they do not traverse any compartments that contain equipment required for that HELB event.

- Heater Drain Pump Discharge

  A dynamic seismic stress analysis is not available for the heater drain system. Therefore, a break must be considered at each weld to a fitting, valve or welded attachment in accordance with the Branch Technical Position Reference 6). Rather than identify each of these locations, it is assumed that a break occurs in every compartment that the lines traverse in the Turbine Hall. A single crack must also be postulated at the most adverse location. However, the effect of the crack would be bounded by the postulated break.

- Other Systems listed in FSAR

  FSAR Appendix A.2.2, High Energy Pipe Failure Outside Containment - Criteria, Item 12 Page A.2-2 lists other systems which were required to be evaluated for HELB impact:

  - Turbine Bypass

    Turbine bypass to condenser is evaluated as part of the Main Steam system and is addressed within it.

  - Sample lines

FSAR Appendix A.2.9, High Energy Pipe Failure Outside Containment - Sample LInes, identifies the Sample lines to be 3/8" which should have been excluded from this analysis by small line size limitation provisions of item 3 of the enclosure to the December 19, 1972, AEC letter (Reference 2). They were not included in the reconstituted program.

Pipe Whip and Jet Impingement

The design of jet impingement shields and pipe rupture restraint protection features are based on the pipe break dynamic effects at design conditions. The EPU evaluations performed did not identify increases in operating conditions that would impact jet impingement and pipe whip analyses outside containment for previously postulated break/crack locations. Implementation of GL 87-11 did not identify any main steam, steam supply to TDAFW pump turbine, steam supply to radwaste services, feedwater or steam generator blowdown postulated break locations that would not have been identified under the original HELB requirements. These systems were discussed in FSAR Appendix A.2, High Energy Pipe Failure Outside Containment.

CVCS letdown piping meets the HE criteria but was not addressed in the FSAR; but it was included in the HELB reconstitution. Since there is no seismic analysis for these portions of these letdown lines, in accordance with the guidance in MEB 3-1, Revision. 2, a break must be postulated at the weld to every fitting, valve or welded attachment for the letdown lines. However, this piping does not traverse any compartments that contain equipment required to mitigate that HELB event. In addition, the relatively low operating pressure (285 psig) and temperature (280°F) would not exert significant thrust loads from the 2", Schedule 40S pipe. As a result, pipe whip and jet impingement evaluations are not required for these lines.

FSAR Appendix A.2, High Energy Pipe Failure Outside Containment, addressed HE systems in the Turbine Building such as Main Steam and Feedwater, but did not specifically address the Condensate, Heater Drains and Extraction Steam systems. These other systems do not have seismic analyses and would have postulated breaks as discussed previously for CVCS letdown. Based on review of the physical location of these lines, none are located near enough to HELB mitigation equipment to require pipe whip or jet impingement evaluations.

The EPU evaluations found no changes were required to the jet impingement and pipe whip analyses for previously postulated break/crack locations, and no new analyses required for the CVCS letdown or other lines in the Turbine building. Therefore, EPU does not affect the current pipe whip analyses or rupture restraints designs for the plant.

Summary of EPU Impact on Building Environments

Pipe failures inside containment are addressed in LR Section 2.6.1, Primary Containment Functional Design, LR Section 2.6.2, Subcompartment Analyses, and LR Section 2.1.6, Leak-Before-Break.

Compartments Outside Containment

The Mass and Energy (M/E) release analysis documents 40 cases to determine the Steam Line Break (SLB) transients of SLB Outside Containment (OC) M/E releases for PBNP Units 1 and 2 at EPU conditions. The case definitions can be summarized as:

- 18 cases located downstream of the MS non-return check isolation valve, maximizing superheat
- 16 cases located upstream of the MS non-return check isolation valve, maximizing superheat
- 5 sensitivity cases that include variations in auxiliary feedwater flowrates, main feedwater flowrates and timing of assumed delays or operator action times
- 1 sensitivity case that illustrates the differences between Unit 1 and Unit 2

The analysis method to generate the mass and energy releases was focused on maximizing the steam superheated enthalpy of the break effluent. However, maximizing the steam enthalpy generally corresponds to lowering the break flowrate, which has the net result of lowering the overall energy release rate. Depending on the compartment characteristics, the equipment location and the time frame of reference, different base assumptions have been found to be more limiting, and thus the reason for the sensitivity cases. It is the compartment temperature analysis and/or the equipment temperature analysis that needs to confirm which set of assumptions is more limiting.

LOFTRAN was used to calculate the M/E releases for the PBNP EPU SLB OC analysis.

From the HELB M/E release outside the Containment, analyses were performed using the GOTHIC (Reference 7) computer code to predict the pressure, temperature, and humidity responses of compartments in the Primary Auxiliary Building (PAB), Containment Facade, and Turbine Building.

The M/E data is required for both pressure and temperature limiting cases. The pressure limiting cases are short term and are most limiting under Hot Zero Power conditions, and the associated M/E data are generated and documented in specific calculations. For temperature limiting cases, a calculation was developed for the main steam at power. There are four unique sets of thermal hydraulic conditions at the break locations.

The mass flux at the break/crack location is calculated using the Extended Henry-Fauske critical flow model for sub-cooled liquid conditions and the Moody critical flow model for saturated steam and liquid conditions. Implementation of these models is described in RETRAN-3D program. Calculations of the mass fluxes were based on the functional fits described the program. Implementation of these functional fits consists of performing the polynomial summations as required by the appropriate equation and using the coefficients shown in the corresponding table. ASME Steam Tables (Reference 8) were used along with the fluid properties (absolute pressure and enthalpy) to determine whether the fluid is subcooled or saturated, establishing the appropriate equation to be used.

The results of the existing and post-EPU compartment pressure and temperature are provided in each corresponding compartment analysis below. LR Section 2.3.1, Environmental Qualification of Electrical Equipment evaluates the impact on the qualification of components required for plant shutdown post HELB from a temperature standpoint in all buildings affected by the releases.

Since the operating conditions for the limiting HELB events are postulated to occur at hot shutdown and are the same for the current and EPU ratings, the EPU project presents no change in the pressure response of the plant.

The peak pressure and temperature at EPU conditions were evaluated for their impact on the outside Containment compartments. The building structural and design features used for mitigation of the resultant pipe failure pressure and temperature were evaluated and do not require modification for protection of equipment required for plant shutdown post HELB due to EPU.

Containment Facade

Numerous breaks and cracks in main steam, feedwater, steam generator blowdown (SGB), condensate return from SGB heat exchangers, etc. are postulated to occur within the Containment Facade on each unit. The Containment Facade is assumed to be a closed volume and pressurizes until a vent relief path is created. The maximum local temperature in this room is calculated to be 360°F.

The Containment Facade is enclosed by metal wall panels attached to the structural steel with some wall and roof areas normally open to the atmosphere. No vent path credit has been taken for these openings. The metal wall panels blow-off at approximately 0.44 psid. The limiting HELB event is the full size 30" main steam break at the containment penetration (a terminal end) at hot shutdown conditions. Based on the blow-off rating during this HELB event, the local pressure in the Containment Facade would peak at a maximum of 0.561 psid before returning to atmospheric after a sufficient number of panels have blownoff or the mass-energy release has been terminated.

- Turbine Building

Numerous breaks and cracks in main steam, feedwater, condensate, bleed steam, heater drain, etc. are postulated to occur within the building on both units. The building is assumed to be a closed volume and pressurizes until a vent relief path is created. The maximum local temperature in this room is calculated to be 243°F.

The building is enclosed by metal wall panels attached to the structural steel. The metal wall panels fail at 0.24 psid. The limiting HELB event is the full size 24" main steam break at the turbine nozzle connection (a terminal end) at hot shutdown conditions. For this HELB event, the building pressure response will be less severe than the Containment Facade results due to the significantly larger net free volume and smaller line break size. Therefore, the pressure would peak at a maximum of 0.24 psid before returning to atmospheric after a sufficient number of panels have failed or the mass-energy releases terminated.

- Primary Auxiliary Building (PAB)

Numerous breaks and cracks in CVCS letdown, main steam and steam supply to the auxiliary feedwater pump turbine are postulated to occur within the building on each unit. The building is assumed to be a closed volume and pressurizes until a vent relief path is created. The maximum local temperature in this room is calculated to be 267°F.

Because of the relatively low operating pressure (285 psig) and temperature (280°F) of the CVCS letdown line and the ability to terminate the HELB event in ten minutes or less, there is no significant pressure increase in the PAB from a CVCS letdown line break.

One of the limiting HELB events is the full size postulated break in the 3" main steam supply to the auxiliary feedwater pump turbine at hot shutdown conditions. The break is located at normally closed valves MS-2019 and MS-2020 (terminal end) in the Primary Auxiliary Building.

The Component Cooling Water Heat Exchanger room is separated from the Spent Fuel Pool Heat Exchanger area by a steel barrier. A pressure relief path (17.5 ft^2) to the Unit 2 main steam line pipe chase was installed by a modification in 2002. There is also a flood damper (6 ft^2) in the west wall of the Component Cooling Water Heat Exchanger room discharging into the Spent Fuel Pool Heat Exchanger area. The damper was installed for flooding purposes and designed to open if water in the Component Cooling Water Heat Exchanger room reached a depth of 30" (approximately 1 psid).

Cracks in the 3" main steam supply to the auxiliary feedwater pump turbine are postulated to occur in the Unit 1 and 2 Primary Auxiliary Building Fan Rooms, CCW Heat Exchanger Room, and the Spent Fuel Pool Heat Exchanger area. Cracks in the 30" main steam lines also are postulated to occur in Unit 1 & 2 Primary Auxiliary Building Fan Rooms. These rooms have access to exterior metal wall panels that fail at 0.44 psid, thereby limiting the pressure in the area. Cracks in the 30" main steam lines are postulated to occur in the vertical pipe chases. These pipe chases are covered at the 66' elevation in the fan rooms and open to the large Turbine Building volume at their bottom.

- Control Building

Environmental conditions in the control building are not affected by high energy pipe failures. The pressure-shielding steel barrier wall between the turbine building and the control building protects the above-identified rooms from the turbine building environment. The EPU does not change the maximum environmental parameters in the turbine building used for the design of the walls.

Flooding Outside Containment

The potential for plant flooding due to a postulated break/crack in a HE system was evaluated. The existing flooding protection for those systems due to piping or components leakage remains capable of performing its safety function as depicted in LR Section 2.5.1.1, Flood Protection, LR Section 2.5.1.1.2, Equipment and Floor Drains, and LR Section 2.5.1.1.3, Circulating Water System (Related to Flooding). Evaluation of flooding effects due to postulated HE line breaks/cracks include discharges of affected fire suppression systems.

- Main Steam System (MS) (including Steam Supply to auxiliary feedwater pump)

The number of postulated MS breaks and cracks were reduced by the change in break postulation methodology, therefore existing flooding mitigating features listed in Appendix A.2, High Energy Pipe Failure Outside Containment, of the FSAR remain unaltered by EPU and the designs are still capable of performing their intended safety function in mitigating flooding effects due to MS HELB.

- Extraction Steam System

Flooding mitigating features related to the Extraction Steam System piping remain unaltered by EPU and the designs are still capable of performing their intended safety function in mitigating flooding effects.

- Condensate

  Condensate System (CS) operating parameters were not significantly changed by EPU. The majority of the CS piping is located in the Turbine Hall. The condensate return from the steam generator blowdown heat exchangers are routed through the Façade, the South Service Building, the Turbine Hall for Unit 1 and the Façade, the Alternate Shutdown Area, the Water Treatment Area and Turbine Hall for Unit 2. This routing was not changed by EPU. and the existing flooding-mitigating features remain unaltered by EPU. These design features are still capable of performing their intended safety function in mitigating flooding effects.

- Feedwater System

  The Feedwater System operating parameters were not significantly changed by EPU, flooding mitigating features in the Turbine Hall and the South Services Building remain unaltered and the designs are still capable of performing their intended safety function in mitigating flooding effects.

- Steam Generator Blowdown System

  The Steam Generator Blowdown System operating parameters were not changed by EPU.

- Chemical and Volume Control System Charging and Letdown Lines

  As noted in the discussion of pipe whip and jet impingement, only the 2" CVCS HE piping was not previously evaluated and this piping traverses areas with no equipment required to remain functional and is capable of releasing small quantities (approximately 870 gal before isolation) of liquids, less than other lines in the surrounding areas. Therefore, flooding caused by a postulated CVCS pipe break outside containment is acceptable for EPU.

- Heater Drain Pump Discharge

  This system is located entirely in the Turbine Hall. The largest line in this system is 14" and is bounded with respect to flooding by other larger lines in its vicinity.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described in the FSAR, the protective barriers associated with high energy line breaks were evaluated for the PBNP License Renewal. The evaluations are documented in License Renewal Safety Evaluation Report (SER) for the PBNP Nuclear Power Plant Units 1 & 2, (NUREG-1839), dated December 2005 (Reference 5). Section 2.4.2, Control Building Structure, of the License Renewal SER addresses aging management review of high energy line break barriers in plant structures. As addressed in the License Renewal SER, Sections 2.3.4.1, Main and Auxiliary System, and 2.3.4.2, Feedwater and Condensate System, the license renewal evaluation boundaries for the main steam and feedwater and Condensate systems were defined consistent with the high energy line break analysis as defined in the HELB

Reconstitution Program. Within the SER, the structures and structural components used to resist the effects of pipe breaks are evaluated within the structure that contains them. Since the EPU does not add any new structures/components used to resist the effects of pipe breaks, nor require the modification of existing structures/components used to resist the effects of pipe breaks, it does not affect the evaluations of these structures in the SER. Aging management of these components is described in the SER Section 3.5, Aging Management of Containments, Structures and Component Supports.

2.5.1.3.3 Results

The analysis performed on compartments outside Containment used the GOTHIC (Reference 7) computer code to predict the pressures and temperatures responses of compartments in the Primary Auxiliary Building (PAB), Containment Facade, and Turbine Building due to HELB events. The impact of the EPU on pipe failures and corresponding pipe whip, jet impingement, environmental conditions, and flooding is evaluated and found acceptable.

Based on evaluations performed, HELB compartment pressure and temperatures at EPU conditions were evaluated for their impact as follows:

- The list of equipment required to mitigate HELB events was reconstituted as part of this effort. Evaluation of the functionality of HELB mitigation equipment is addressed LR Section 2.3.1, Environmental Qualification of Electrical Equipment.
- The building structural and design features utilized for mitigation of the resultant pipe failure pressure and temperature were evaluated and continue to provide adequate protection for safety related equipment.

The evaluations at EPU conditions do not create any new postulated pipe break locations for the systems identified in the FSAR. The CVCS system, not addressed in the original analysis, was evaluated. The results of the CVCS evaluation indicate no effect on required building or components that is not bounded by postulated failures in other systems. The jet impingement shields, pipe whip restraints and flood mitigation features installed as protection for the effects of piping failures remain acceptable for the EPU. Therefore, the analyses demonstrate that no modifications are required due to HELB for operation at EPU conditions.

2.5.1.3.4 Conclusion

PBNP has assessed the effects of the changes that are necessary for the proposed EPU and the proposed operation of the plant and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems outside containment and will continue to meet the requirements of PBNP GDC 40 with NRC approval of the proposed HELB licensing basis following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to protection against piping failures in fluid systems outside containment.

2.5.1.3.5 References

1. Shapiro, A. H., The Dynamics and Thermodynamics of Compressible Fluid Flow, Vol. 1, Ronald Press, New York, New York, 1953
2. US AEC to WEPCo, Regulatory Staff Review of Reactor Power Plant Safety Re: Consequences of Postulated Pipe Failures Outside the Containment Structure, December 19, 1972
3. Automated Engineering Services Corp, PBNP HELB Reconstitution Program Task 1 Report, September 17, 2008
4. NRC Generic Letter (GL) 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, June 19, 1987
5. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005
6. Branch Technical Position MEB 3-1, Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2 dated June 1987
7. NAI 8907 06, Revision 16, GOTHIC Containment Analysis Package Technical Manual, Version 7.2a, January 2006
8. ASME Steam Tables, Properties of Saturated and Superheated Steam in U.S. Customary and SI Units from the IAPWS-IF97 International Standard for Industrial Use, 2006

Table 2.5.1.3-1 List of High Energy Lines and the Change in Operating Conditions

Line Description	1545 Mwt Design Press psig	1806 Mwt Design Press psig	1545 Mwt Oper. Temp °F	1806 Mwt Oper. Temp °F
High pressure turbine to #5 heaters	400	525(1)	438	461
#2 FW Heaters to #3 Heaters	400	400	205	215
#3 FW Heaters to #4 Heaters	400	400	272	284
#4 FW Heaters to Feedwater Pump suctions	400	400	347	361
From Steam Generator Blowdown Heat Exchangers	400	400	325	320
Containment to non-regenerative Heat Exchangers	700	700	280	280
Feedwater Pumps to #5 Heaters	1525	1525	351	365
#5 FW Heaters to Containment	1525	1525	431	457
Feedwater Pump recirculation to Condensers	1525	1525	351	365
#5 FW Heaters to Control Valve to #4 Heaters and Condensers	370	525(2)	359	375
Heater Drain Pumps to Feedwater Pump suction	517	517	352	365
#3 Heater Vents	550	550	278	289
#4 Heater Vents	550	550	351	366
MS from Containment to various services	1085	1085	547	547
Reheater Drains to #5 Heaters and Condensers	1085	1085	511	507
S/G Blowdown from Containment to Angle Valves and Heat Exchangers	1085	1085	547	547

Notes:

1. Extraction steam maximum operating pressure increased above the system design pressure in this location. The new design value (Shell side pressure of the #5 heater) was found acceptable. The calculated wall thickness of the existing piping at the new design value was found to be acceptable for operation at EPU conditions.
2. FW Heater Drain maximum operating pressure increased above the system design pressure in this location. The new design value was found acceptable. The calculated wall thickness of the existing piping at the new design value was found to be acceptable for operation at EPU conditions.

2.5.1.4 Fire Protection

2.5.1.4.1 Regulatory Evaluation

The purpose of the fire protection program is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The PBNP review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that structures, systems, and components (SSCs) required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire.

The NRC's acceptance criteria for the fire protection program are based on:

- 10 CFR 50.48 and associated Appendix R to 10 CFR 50, insofar as they require the development of a fire protection program (FPP) to ensure, among other things, the capability to safely shutdown the plant.
- GDC 3, insofar as it requires that:
  - SSCs important-to-safety be designed and located to minimize the probability and effect of fires.
  - Noncombustible and heat resistant materials be used.
  - Fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety.
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.5.1, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

PBNP Current Licensing Basis

The design philosophy and specifics of the fire protection system are contained in the PBNP Fire Protection Evaluation Report (FPER). The FPER is the "umbrella" document that describes the PBNP program requirements, including the commitments and exemptions to 10 CFR 50.48, Appendix A of Branch Technical Position (BTP) APCSB 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976, and the applicable requirements of 10 CFR 50 Appendix R. A summary of the exemptions granted to PBNP is presented in the FPER. The FPER is incorporated by reference into the Final Safety Analysis Report (FSAR). Additional provisions are provided for the period of extended operation in the Fire Protection Program outlined in FSAR Section 15.2.10, Fire Protection Program.

The FPER serves as PBNP's fire plan as described in 10 CFR 50.48 and additionally documents PBNP's compliance with Criterion 3 of Appendix A of 10 CFR 50, which states:

PBNP GDC CRITERION 3 – Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

As noted in FSAR, Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

A reactor facility shall be designed to ensure that the probability of events such as fires and explosions and the potential consequences of such events will not result in undue risk to the health and safety of the public. Noncombustible and fire resistant materials shall be used throughout the facility wherever necessary to preclude such risk, particularly in area containing critical portions of the facility such as containment, control room, and components of engineered safety features. (PBNP GDC 3)

The FPER serves as PBNP's fire plan as described in 10 CFR 50.48 and additionally documents PBNP's compliance with Criterion 3.

Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

The FPER is incorporated into the FSAR by reference consistent with the guidance of NRC Generic Letter 86-10, (Implementation of Fire Protection Requirements, Reference 3), and encompasses the current fire protection commitments affecting the Fire Protection Program. FPER revisions are conducted in accordance with the requirements of PBNP License Condition 4.F to ensure the retention of Fire Protection Program commitments.

In addition, the Fire Hazards Analysis Report (FHAR) provides plant as-built information characterizing the fire hazards and fire protection features on a zone-by-zone basis. The FHAR is consistent with the information submitted in 1977 that is part of the basis for the PBNP SEs and supplements referenced in License Condition 4.F and described in the FSAR and FPER.

The FHAR provides documentation links to various lower-tier documents such as the plant fire protection area drawings, system drawings, and applicable engineering evaluations. Regulatory commitments relating to specific plant areas appearing in PBNP SERs, etc. are identified in the applicable fire zone to assist PBNP personnel in identifying the impact of proposed changes to the program. In addition, if Fire Protection Engineering Evaluations (GL 86-10 evaluations, Reference 3) are applicable to a specific fire zone, they are referenced in the fire zone write-up. Proposed changes to a fire zone are evaluated in accordance with the modification process. Changes required to the FHAR are identified as part of the modification. The FHAR is updated to reflect changes to the plant.

The Safe Shutdown Analysis Report (SSAR) is the upper-tier document that describes the analysis methodology, approach, key assumptions, and results, as supported by lower-tier information (e.g. analysis databases, design calculations, area evaluations, operator action feasibility studies, etc.). The SSAR provides documentation links to the supporting lower-tier documents where the actual analysis and supporting documents reside. A subset of this document is repeated in the FPER for the purpose of addressing key regulatory positions and the compliance approach.

In addition to the evaluations described in the FSAR, the PBNP Fire Protection Program was evaluated for plant license renewal. The evaluation is documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG 1839), dated December 2005 (Reference 1)

The fire protection program/systems are addressed in Sections 2.3.3.6 and 3.3.2.3.7 of the safety evaluation report. Fire barrier materials are addressed as a commodity group, while walls, floors, doors, structural steel etc., are evaluated within the building that contains them. Components credited with achieving safe shutdown following a fire are evaluated within the system that contains them.

2.5.1.4.2 Technical Evaluation

Introduction

The purpose of the PBNP Fire Protection Program is to provide assurance, through defense-in-depth design, that a fire will not prevent the performance of necessary safe shutdown functions or significantly increase the risk of radioactive release to the environment during a postulated fire.

The PBNP Fire Protection Program includes the following upper tier documents, FSAR; Fire Protection Evaluation Report (FPER); Fire Hazards Analysis Report (FHAR) and Safe Shutdown Analysis Report (SSAR) as described below.

Fire Protection Evaluation Report (FPER)

The Fire Protection Evaluation Report (FPER) describes the PBNP Fire Protection Program and how the program requirements are implemented for Point Beach Nuclear Plant (PBNP).

FSAR Section 7.5.3.2, Operating Control Stations - Fire Prevention Design, refers to the FPER for information concerning fire protection features and contingency actions related to postulated control room fires, consistent with the guidance of NRC Generic Letter 86-10 (Reference 3).

The FPER addresses both the earlier NRC requirements related to protecting the plant against fire hazards and the Appendix R safe shutdown regulations. It is intended that the FPER provide summary-level information regarding these general areas and that the next lower level of upper-tier documents provide more detailed but still summary-level information. As a result, the FPER refers to the SSAR and FHAR for supporting details related to the methodology, compliance approach, and results of supporting analysis.

As indicated in Section 2.0 of the FPER, the Safe Shutdown System Logic Diagrams (SLD) and Component Logic Diagrams (CLD), and an associated Safe Shutdown Equipment List (SSEL) identify the inter-relationship of essential plant systems and components required to achieve and maintain hot and cold shutdown in accordance with Appendix R requirements. The SLD provides a "big picture" overview and shows the relationships between the essential systems. Safe Shutdown CLD provide the detailed component requirements for each of the systems described on the SLD. The logic diagrams are discussed in greater detail in Section 2 of the SSAR and are included as Appendix B to the SSAR. As addressed in FPER Section 3.1.4.5.1, Fire Emergency Plans (FEP), in accordance with 10 CFR 50 Appendix R, PBNP maintains FEPs and provides a reference document with the appropriate information so that the fire brigade may conduct a safe and effective attack on a fire in a particular plant area.

The location of the general plant area covered by the plan is provided by common name and elevation. Guidelines for fire attack are provided to enhance the attack and provide an awareness of the safety of individual fire fighters. Fire, radiological, electrical, and physical hazards are listed for each plan area. Adjacent hazards or areas of easy fire extension are listed as exposures. Communications are listed as to the acceptability of FM radio transmissions and location of public paging stations. Access and egress to areas are indicated to ensure prompt fire brigade response and to point out possible escape routes. Ventilation methods and precautions are provided. Installed fire suppression systems located in the plan area are indicated, along with available fire suppression equipment located nearby. The general plan includes notes on construction details to aid in determining the possibility of fire spread or collapse of structures.

The Safe Shutdown Capability is addressed in Section 5.2 of the FPER. The capabilities of systems and features used to achieve safe shutdown are based on the design basis capabilities of the systems and components. Calculations have been developed to demonstrate that the system capabilities meet the performance requirements relied on in the FPER and SSAR.

The safe shutdown components represent the minimum set of areas/Zones and components used to achieve Appendix R safe shutdown using either preferred or alternative capabilities. These are identified and listed in Section 7.0 of the FPER, Fire Hazard Analysis. These analyses have been performed for all safe shutdown related fire zones and significant non-safe shutdown fire zones. The fire hazard analyses methodology is described in the Fire Hazards Analysis Report (FHAR).

Fire Hazards Analysis Report (FHAR)

The FHAR determines the adequacy of the plant fire protection features to provide adequate defense in depth against the specific fire hazards in each location. The FHAR defines the plant fire areas, determines the potential sources of combustion and design fire loading, describes the fire detection and extinguishing capabilities, identifies the equipment within the area, and determine the potential consequences of a design basis fire.

The FHAR provides listings of the fire areas and the fire zones within each area. A fire hazards analysis for each area is included in the FHAR. Each analysis reviews the fire hazards within the area and their exposure to safety-related equipment and components necessary for safe shutdown within the area. The type and quantity of combustible materials, type of fire hazards these materials present in the area and the fire protection features for the area were reviewed. The effects of the postulated fires on the performance of safe shutdown functions and the minimization of radioactive releases to the environment were evaluated.

Safe Shutdown Analysis Report (SSAR)

The SSAR describes PBNP's Appendix R safe shutdown capability and method of addressing the requirements established in Section III.G, Fire Protection of Safe Shutdown Capability, Section III.J, Emergency Lighting, Section III.L Alternative and Dedicated Shutdown Capability, and Section III.O, Oil Collection System for Reactor Coolant Pump, of Appendix R.

Description of Analyses and Evaluations

Fire Protection

Operating at increased core power level, along with the associated increase in decay heat, does not affect the following elements of the fire protection program:

- Addition of new combustible material
- Fire barriers, penetrations, doors, or the plant radio system
- Ventilation air flow patterns
- Plant fire programs or the Fire Protection Evaluation Report
- Fire wrap and fire coatings on structural steel
- Fire protection suppression or fire detection system components
- Safety-related components within an area protected by the fire suppression system

Some of these elements can be affected by plant modifications required in support of EPU. Changes made for each plant modification are reviewed in accordance with the current plant procedures to ensure that there are no adverse affects to the existing Fire Protection Program requirements.

The EPU does not affect the elements of the fire protection program related to administrative controls and fire protection responsibilities of plant personnel.

The EPU will not result in an increase in the potential for a radiological release resulting from a fire.

The EPU will not change the PBNP compliance with Appendix R or NRC approved exemptions.

Safe Shutdown Analyses

Safe Shutdown Systems and Components

The Safe Shutdown Analysis (SSAR) identifies the specific systems credited with achieving safe shutdown using either preferred or alternative capabilities. The safe shutdown components, which represent the minimum set of components used to achieve Appendix R safe shutdown using either preferred or alternative capabilities are identified in a plant database.

The EPU does not affect the minimum set of safe shutdown systems/components, including cables, credited with achieving safe shutdown using either preferred or alternative capabilities. Plant modifications required in support of the EPU are reviewed to ensure any design changes do not adversely affect existing compliance methods or the actions taken to mitigate the effect.

Control of Appendix R Safe Shutdown Equipment

The SSAR assumes all safe shutdown equipment is available and in their normal position at the beginning of an Appendix R fire event. During routine operation of the plant it may be necessary to take one or more of those components out of service. Therefore, administrative controls are established to ensure that the Appendix R Safe Shutdown Equipment will be available to perform its intended safe shutdown function. The out-of-service time of such equipment is restricted by the applicable Technical Specification(s) or 30 days, whichever is more limiting. If the out-of-service time requirement cannot be met, appropriate compensatory measures are implemented to address the impaired post fire safe shutdown function within the following 72 hours and action is initiated in accordance with the station corrective action program.

The EPU does not affect the administrative controls or out-of-service times established that would affect the Appendix R Safe Shutdown Equipment availability to perform its intended safe shutdown function.

Alternative/Dedicated or Backup Shutdown Capability

The safe shutdown analysis was performed to consider the potential fire damage to the plant shutdown capability and to demonstrate that the plant can achieve safe shutdown in accordance with the requirements of 10 CFR 50.48 and 10 CFR 50 Appendix R for a fire in any location of the plant.

Alternative or Alternate Shutdown is applicable to those areas where a diverse system is used in lieu of the preferred system because redundant components of the preferred system do not meet the separation criteria of Section III.G.2 of Appendix R. Alternative Shutdown is governed by Sections III.G.3 and III.L of Appendix R and generally involves one or both of the following conditions:

- Key shutdown activities are controlled/conducted outside of the Control Room (e.g., from alternate shutdown locations), or
- Plant systems are used in a manner that is diverse from their intended design function. Table 5.2.1-1 of the FPER identifies specific areas in the plant, their associated fire zones and whether they are considered normal or alternate shutdown capable.

The following areas have been identified as alternative shutdown areas:

- Control Room
- Cable Spreading Room
- Computer and Instrument Rack Room
- 4160 V Vital Switchgear Room
- Monitor Tank Room (C-59 area) and Primary Auxiliary Building 26' Central Area

- Component Cooling Water Heat Exchanger and Boric Acid Tank Room (Primary Auxiliary Building, El. 44' Central Area)

Defense in depth is implemented using a philosophy that starts with and emphasizes a strong fire prevention program to reduce or eliminate the potential for fires occurring at PBNP. In the event there is a breakdown of the prevention program, fire protection features have been incorporated into the plant design to ensure fires are detected early and contained to an area where they will not jeopardize the plant's safe operation or shutdown capability.

Preventive maintenance and administrative control programs exist to monitor and maintain these fire protection features to ensure they remain available. Alternative measures are taken to compensate for these features when they have been removed from service. This defense-in-depth fire protection program consists of a number of plant features, which together form the overall program. The program consists of both programmatic and plant fire protection equipment and systems. It also includes a fire protection safe shutdown analysis performed and maintained to demonstrate the plant's safe shutdown capability in the event of a fire in accordance with 10 CFR 50 Appendix R.

The fire protection program incorporates six specific concepts, namely: fire prevention, protection, detection, suppression, containment, and separation.

The FPER also addresses all required aspects of Separation Criteria for Safe Shutdown Capability. The separation criterion is not affected by the EPU unless a modification is created. As such, the modification process will control the changes to the alternative/dedicated or backup shutdown capability.

Other than modifications to the plant, governed by processes which assess the effect on Fire Protection Program, EPU does not affect the alternative shutdown methods. Modifications required as a result of EPU that modify the function of any mechanical component in the alternative safe shutdown flow paths, modify any components or circuits that provide power, control, or indication to components required for alternative safe shutdown, or introduce any plant equipment failure modes which will affect the ability to achieve any of the alternative shutdown functions, will be addressed as part of the plant modification process.

Post Fire Safe Shutdown Procedures

Post-fire shutdown procedures are provided to ensure operators have sufficient guidance and instruction to safely shutdown the plant in the event of fire. The procedures implement the shutdown methods that are supported by the safe shutdown analysis.

The time-critical actions included on various response procedures are potentially affected by the increased power level and decay heat resulting from EPU. These are addressed below.

Appendix R Compliance Strategies

SSAR Section 2.3.2, Safe Shutdown Systems provides a summary level discussion of the systems used to support safe shutdown following a fire or whose spurious operation or failure could adversely affect safe shutdown. SSAR Table 2-1A provides a summary of the safe shutdown logic diagrams that are included in Appendix C of the SSAR. SSAR Table 2-1B provides a summary of the Appendix R P&IDs that are included in Appendix D of the SSAR.

SSAR Table 2-3 of the Shutdown Analysis indicates several scenarios where potential spurious malfunction could affect the safe shutdown of the plant. In addition, a summary of calculations that have been performed to support the selection of systems and equipment to satisfy the Appendix R Functional Requirements is included as Table 2-4 of the SSAR including 29 time-critical and functional tasks discussed below. An assessment of the EPU effect on each is included.

1. Reactor Coolant System (RCS) Depressurization without Heaters, Sprays, Power Operated Relief Valves (PORVs)

   SSAR Discussion: The Reactor Coolant System can be cooled to cold shutdown in 72 hours using natural circulation cooldown without the use of pressurizer heaters, pressurizer sprays and pressurizer PORVs.

   EPU Evaluation: The capability of achieving cold shutdown within 72 hours using natural circulation following an Appendix R fire scenario has been verified for EPU operation.

2. Charging Seal Flow Adequacy

   SSAR Discussion: The Reactor Coolant Pump (RCP) seal injection provides sufficient flow to each RCP to maintain the pressurizer at a constant level during cooldown. If RCP seal injection is lost, at least 40 minutes is available to regain charging prior to emptying the pressurizer. If RCP seal injection is lost, resulting in increased RCS inventory loss beyond Technical Specification leak rates, and at least one charging pump is restored within 30 minutes at full capacity, it is possible to achieve Cold Shutdown at a cooldown of 25°F/hr while retaining pressurizer level within the indicating range during the cooldown.

   EPU Evaluation: The capability of achieving cold shutdown in the event of loss of RCP seal injection following an Appendix R fire scenario has been verified for EPU operation.

3. Loss of Seal Injection – Seal Cooling

   SSAR Discussion: The loss of seal injection and thermal barrier cooling coincident to an Appendix R fire results in RCP seal leakage increasing from 3 gpm/pump to 21.1 gpm/pump, assuming no additional seal failures are postulated. Under these conditions, the pressurizer will not empty and cooldown at 25°F/hr can be achieved if at least one charging pump at full capacity is restored within 50 minutes.

   EPU Evaluation: The capability of restoring one charging pump following an Appendix R scenario within 50 minutes is unchanged for EPU operation and the time required for restoring one charging pump is also unchanged.

4. RWST Adequacy

   SSAR Discussion: Current analysis provided in the FPER states that the capacity of the Refueling Water Storage Tank (RWST) is in excess of that required for safe shutdown. This assumes that the water mass available from the RWST is sufficient to compensate for the change in water volume in the RCS due to shrinkage during cooldown.

EPU Evaluation: The capability of achieving cold shutdown using makeup water from the RWST following an Appendix R fire scenario has been verified for EPU operation with no increase in water available in the RWST.

5. RWST Boration Capability

   SSAR Discussion: Borated water is provided by charging from the RWST via the seal injection flowpath. Current analysis provided in the FPER states that the RCS boron concentration increase due to the addition of RWST makeup water is sufficient to maintain adequate shutdown margin.

   EPU Evaluation: The capability of maintaining adequate shutdown margin when using borated water from the RWST has been verified for EPU operation with no change in RWST boron concentration.

6. Spurious Operation of Pressurizer Heaters

   SSAR Discussion: In the event of spurious operation of pressurizer heaters, combined with the failure of pressurizer spray to operate, bursting of the Pressure Relief Tank (PRT) rupture disk will occur in approximately 1.3 hours.

   EPU Evaluation: The capability to de-energize the pressurizer heaters before the rupture of the PRT disc has been verified for EPU operation and the time required for mitigating action is not changed.

7. Normal/Excess Letdown Inventory Loss

   SSAR Discussion: The time available to isolate normal letdown in order to maintain RCS inventory is about 7 minutes. The time available to isolate excess letdown before an unrecoverable adverse consequence occurs is 45 minutes.

   EPU Evaluation: The capability of isolating normal and excess letdown has been verified for EPU operation and the time required to isolate excess letdown is not changed.

8. Spurious Normal/Auxiliary Spray

   SSAR Discussion: In the event of spurious normal or auxiliary pressurizer spray, filling of the pressurizer (unacceptable consequence if Safety Injection (SI) initiates) will occur in about 2 minutes. Forming a steam void in the reactor vessel (unacceptable consequence if SI fails to initiate) will occur in about 1 minute.

EPU Evaluation: The capability to isolate spurious normal and auxiliary pressurizer spray in order to maintain RCS pressure control has been verified for EPU operation and the time required for the unacceptable consequences as stated, are not changed.

9. RWST Draindown

SSAR Discussion: The potential for draining the RWST into the containment sump via SI Valves SI-856A(B), 850A (B), and 851A(B) due to spurious valve operation, is improbable because at least one of the two valves in series SI-851A or B and SI-850A or B remains closed in the flow path. Therefore, the RWST drain is limited to that of the seat leakage of both trains of the closed valves in line with the spuriously opened valve.

EPU Evaluation: The position of the valves has been verified for EPU conditions and the drain is still limited to that of the seat leakage of both trains of the closed valves in line with the spuriously opened valve. The potential for draining the RWST due to spurious valve operation remains improbable post EPU.

10. Volume Control Tank (VCT) Isolation Time Constraints

SSAR Discussion: In the event of an Appendix R fire scenario, borated water will be provided by charging from the RWST via the seal injection flowpath. The VCT is isolated to allow for emergency make-up from the RWST by isolation of the VCT outlet valve. The VCT must be isolated, or the running charging pumps secured, within ~9 minutes, to avoid an unrecoverable loss of charging capability.

EPU Evaluation: The charging capability of borated water from the RWST via the seal injection flowpath has been verified for EPU operation and the time required for isolating the VCT or securing the running charging pumps is not changed.

11. Spurious PORV Opening

SSAR Discussion: In the event of spurious PORV actuation, the unacceptable consequence of the PRT rupture disc failing will occur in approximately 200 seconds. In the event of spurious actuation of the reactor head vent or pressurizer vent valves, the unacceptable consequence of the PRT rupture disc failing will occur in approximately 1 hour and 2.4 hours, respectively.

EPU Evaluation: The time before unacceptable consequences of the PRT rupture disc failing due to spurious PORV actuation or spurious actuation of the reactor head vent or pressurizer vent valves is not changed due to EPU.

12. Spurious Safety Injection/Containment Spray Pump Actuation

SSAR Discussion: A spurious SI pump start at reduced RCS pressure could result in an uncontrolled increase in RCS inventory, while a spurious Containment Spray (CS) initiation could result in the depletion of water from the RWST into containment. The unacceptable consequences of filling the pressurizer occur in 2.3 minutes. Potential overheating of the SI pump occurs between 17 and 27 minutes after reaching shutoff head pressure. In the event of a spurious CS actuation of both trains (2 pumps and both CS valves) the unacceptable consequence of falling below the minimum required RWST level occurs in about 60 minutes. One train will drain the RWST in approximately 120 minutes.

EPU Evaluation: The probability of a spurious SI pump start or spurious CS initiation is unchanged for EPU operations and the time required for mitigating actions as stated above is not changed. Pending LAR 241 (ML083450683) discusses modifications to the controls of these pumps and throttling the pump discharges, which may increase the time permissible prior to unacceptable consequences.

13. Condensate Storage Tank (CST) Depletion

SSAR Discussion: When condensate inventory required for RCS heat removal is exhausted or the Auxiliary Feedwater (AFW) pump suction pressure decreases to less than 7 psig, it is necessary to shift to the Service Water system as an alternate source of supply. In the most limiting circumstances, an alternate source of AFW (e.g., from the Service Water system or the fire main) is required one hour following initiation of steam generator (SG) feed.

EPU Evaluation: Due to the higher decay heat, AFW flow to the SGs is higher and the CST is depleted more quickly. Switchover to an alternate source within one hour is unchanged by EPU. The time required to shift to an alternate source of water supply is being improved by the EPU modifications to the AFW system described in LR Section 2.5.4.5, Auxiliary Feedwater, which provide automatic suction switchover from the CST to Service Water.

14. Cooldown using One Residual Heat Removal (RHR) Pump and Heat Exchanger per Unit

SSAR Discussion: The RHR system can be placed in operation when the temperature and pressure of the RCS are less than 425 psig and 350°, respectively. The FPER states that cooldown of the plant is not affected if one of the pumps and/or one of the heat exchangers are unavailable. Cold shutdown conditions can still be reached within 72 hours using a single RHR pump and heat exchanger, while complying with the temperature and cooldown rate limits of existing procedures.

EPU Evaluation: Capability to achieve cold shutdown using a single RHR pump and heat exchanger within the temperature and cooldown rate limits of existing procedures has been verified for EPU operations.

15. Cooldown using One Component Cooling Water (CCW) Pump

SSAR Discussion: Two CCW pumps and four CCW heat exchangers are normally used to remove sensible and decay heat during cooldown for both units. However, the plant can be placed in cold shutdown within 72 hours under 10 CFR 50 Appendix R conditions with a single CCW pump and two CCW heat exchangers in operation, within the temperature and cooldown rate limits of existing procedures.

EPU Evaluation: The capability to achieve cold shutdown within 72 hours using a single CCW pump and two CCW heat exchangers within the temperature and cooldown rate limits of existing procedures has been verified for EPU operations.

SSAR Discussion: Valves 1CC-824B and 2CC-824B should be initially set to 26° open prior to starting the CCW pump in order to reach (approximately) the CCW flow to the Residual Heat Removal (RHR) heat exchangers specified and avoid CCW pump runout.

EPU Evaluation: The lineup of the valves prior to starting the CCW pump in order to avoid CCW pump runout under the above conditions is not changed for EPU.

16. Necessity of CCW/Service Water (SW) non-essential load isolation

SSAR Discussion: Isolation of all CCW flow paths except for the "B" RHR Heat exchangers, the "B" RHR pump seal water coolers, and the RCPs is assumed, in order to maximize the CCW flow available to support the heat removal process.

EPU Evaluation: EPU evaluations confirmed that the CCW flow remains adequate to support the heat removal process if all CCW flow paths except for the "B" RHR Heat exchangers, the "B" RHR pump seal water coolers, and the RCPs are isolated.

SSAR Discussion: Two SW pumps will provide sufficient cooling flow to essential equipment during plant cooldown using the Residual Heat Removal (RHR) system, following an Appendix R fire. Isolation of some non-essential SW system loads is required in order to achieve satisfactory flow to essential equipment and adequate SW header pressure.

EPU Evaluation: EPU evaluations confirmed that the SW system flow to essential equipment and adequate SW header pressure has been verified for EPU conditions and is not changed.

17. Spurious Atmospheric Dump Valve Actuation (ADV)

SSAR Discussion: Where a fire spuriously opens an ADV, the unacceptable consequence of drying out the Steam Generator will occur between 14 and 49 minutes, depending upon the unit involved and initial conditions.

EPU Evaluation: The time to SG dryout in case of a spurious opening of an SG ADV has been verified for EPU to remain between 14 and 49 minutes, depending upon the unit involved and initial conditions and the time due to conservative assumptions in the original analysis.

18. Time to Restore Auxiliary Feedwater (AFW)

SSAR Discussion: Following a postulated fire, Auxiliary Feedwater (AFW) flow may be established using the AFW pumps. AFW flow to the Steam Generators (SGs) must be established within 50 minutes.

EPU Evaluation: EPU evaluations confirmed that establishing flow to the SGs within 50 minutes remains unchanged.

19. Time to Isolate Main Feedwater

    SSAR Discussion: In the event that one or both main feedwater pumps are feeding the SGs, the unacceptable consequence of filling the Steam Generators to the Main Steam line will occur in approximately 2 to 4 minutes, depending on the unit and the number of main feedwater pumps running.

    EPU Evaluation: Due to the increased feedwater flow rate at EPU conditions, the time for the unacceptable consequence of filling the SG to the Main Steam line is reduced slightly but remains at approximately 2 to 4 (1.9 to 3.8) minutes. Operation of the condensate and feedwater system, including isolation features during postulated abnormal and accident scenarios, is discussed in LR Section 2.4.2.1, Plant Operability (Margin to Trip).

20. Time to Isolate SG Blowdown or Sampling Lines

    SSAR Discussion: Methodology presented in the logic diagrams requires isolation of the SG blowdown and sampling lines in addition to the Main Steam lines in order to achieve Steam Generator isolation. In the event that the blowdown and/or sample valves remain open or spuriously open during an Appendix R fire, the unacceptable consequence of losing the secondary heat sink will occur no earlier than 195 minutes (Unit 1) and 156 minutes (Unit 2).

    EPU Evaluation: The time to reach the unacceptable consequence of losing the secondary heat sink due to un-isolated SG blowdown or sampling line during an Appendix R fire is unchanged for EPU since the rate of blowdown would be unchanged for each unit.

21. Cooldown using One Motor-Driven AFW Pump

    SSAR Discussion: One (1) SG and one (1) Motor-Driven AFW pump can accommodate the decay heat and a natural circulation cooldown to the point at which RHR can be initiated. The minimum cooldown rate that can be used and still achieve cold shutdown conditions within 72 hours is approximately 4.5°F/hr.

    EPU Evaluation: The capability to accommodate the decay heat and a natural circulation cooldown to the point at which RHR can be initiated, using one (1) SG and one (1) Motor-Driven AFW pump has been verified for EPU operations. The minimum cooldown rate that can be used and still achieve cold shutdown conditions within 72-hours is unchanged at approximately 4.5°F/hour.

22. Loss of Auxiliary Feedwater Pump Bearing Cooling

    SSAR Discussion: Under worst-case Appendix R conditions, a minimum of approximately 42 minutes is available to restore bearing cooling water to the Turbine-Driven Auxiliary

Feedwater pump before bearing temperature reaches 200°F; a conservative temperature limit that would preclude damage to the bearings.

EPU Evaluation: The time available to restore bearing cooling water to the Turbine-Driven Auxiliary Feedwater pump is unchanged for EPU.

23. Primary Sampling/ Reactor Vessel Flange Leak Detection Leakoff

SSAR Discussion: The flow path for RCS inventory control presented in the logic diagram for the Reactor Coolant System does not include isolation of the reactor vessel flange leak detection or primary sampling system flow paths. Under worst-case Appendix R conditions, the spurious operation of valves in the Primary Sample System will result in a 0.3 gpm loss of RCS inventory. Leakage into the Reactor Vessel Flange Leak Detection System will not change from its pre-fire condition, and existing leakage will have been accounted for under PBNP Technical Specification requirements.

EPU Evaluation: The loss of RCS inventory due to spurious operation of valves in the primary sample system or the reactor vessel flange leak detection system is unchanged by EPU.

24. Loss of Heat Tracing/Freeze Protection

SSAR Discussion: Heat tracing is required to prevent lines from the RWST from freezing inside the façade. Heat trace is not identified in the methodology presented in the logic diagrams. The RWST inlet line, RWST outlet line, the Engineering Safeguards Pump Recirculation line, Steam Generator pressure instrument sensing lines, and the steam supply line to TDAFW pump P-29 were evaluated to determine the time available to take remedial action before water in the line would freeze. For each pipe in question, the time for the fluid to freeze is either: 1) greater than the 72-hour Appendix R required shutdown time or 2) provides at least two (2) hours for mitigating action to be taken.

EPU Evaluation: The requirements for freeze protection for the RWST lines inside the façade are unaffected by EPU.

25. Loss of Heat Ventilation And Air Conditioning (HVAC) Systems

SSAR Discussion: HVAC systems are identified in the methodology presented in the logic diagrams as that the systems could potentially be used to support safe shutdown, including systems such as the AFW pump room ventilation, cable spreading room ventilation, vital switchgear room ventilation, control room ventilation, EDG (emergency diesel generator) room ventilation, battery and inverter room ventilation and containment ventilation.

The equipment in the control room, computer room, cable spreading room, vital switchgear room, and AFW pump room will remain operable provided portable ventilation is established.

EPU Evaluation: The capability to provide portable ventilation under EPU conditions is not changed. Requirements for the EDG room ventilation are not changed by EPU.

SSAR Discussion: The containment response to a PORV discharge leads to PRT rupture disk failure. The effect of loss of containment HVAC is bounded by this condition.

EPU Evaluation: Evaluations for EPU conditions verify that containment response to a PORV discharge remains within design limits and unchanged. The effect of loss of containment HVAC under EPU conditions is still bounded by the containment response to a PORV discharge leading to a PRT rupture disk failure.

SSAR Discussion: Battery chargers in the West Inverter Room will remain operable provided emergency ventilation is established prior to reaching 122°F. The time available to establish emergency ventilation is approximately eight (8) hrs from loss of ventilation, conservatively assuming no normally-operating equipment is shut down.

EPU Evaluation: Response to a loss of ventilation affecting the operability of the battery chargers is not changed by EPU including the time for establishing emergency ventilation.

26. Loss Emergency Diesel Generator (EDG) G-01/G-02 Service Water Cooling

SSAR Discussion: EDG's G-01 and G-02 require Service Water cooling to the engine cooling water heat exchangers, to operate while loaded with safe shutdown loads. Three (3) minutes is the time limit for DG operation without Service Water at full load.

EPU Evaluation: Use of the EDG is not changed by EPU except for small changes in the load profile. Service water flow rate to the EDG cooling system is based on EDG rating which is not changed for EPU. The capability of the EDG to operate without Service Water at full load is not changed for EPU.

27. Diesel Fuel Oil Capacity

SSAR Discussion: For any two EDG's (G-01, G-02, G-03 or G-04), there is sufficient fuel on-site to satisfy the 72-hour Appendix R requirement with the administratively required 34,500 gallons of DG fuel oil available.

For the gas turbine generator (G05) there is sufficient fuel capacity on-site to satisfy the 72 hour Appendix R requirement. Administrative controls are required to ensure that a minimum level of approximately 94,000 gallons of diesel fuel oil is maintained in the two 60,000 gallon storage tanks.

EPU Evaluation: The EPU conditions have little or no effect on the required stored quantities of diesel fuel. Refer to LR Section 2.5.7.1, Emergency Diesel Engine Fuel Oil Storage and Transfer System, for additional information.

28. Containment Environment

SSAR Discussion: Containment environment (temperature, pressure and humidity) was evaluated for postulated Appendix R scenarios and accessibility was established to plant personnel under these conditions. The failure of the PORV to the PRT is the event that would most challenge the containment environment, which may limit personnel accessibility for equipment manipulation. A simulator run indicated that approximately 30 minutes after the PRT rupture disc fails, the containment temperature and pressure are 112°F and 3.2 psig, respectively, with both parameters still increasing. In addition, the observed radiation levels were at 1 REM and also slowly increasing.

EPU Evaluation: Based on PBNP design basis, containment entry was evaluated to be not viable for certain Appendix R scenarios. Therefore, requirements for containment entry for Appendix R events are not changed for EPU conditions.

29. Shutdown Margin

SSAR Discussion: The shutdown margin during the cooldown and xenon transient after an Appendix R event is determined and indicates that charging is sufficient to maintain shutdown margin for a bounding 18-month fuel cycle. RCS charging is assumed to be equal to 55 gpm with RCP seal leakage.

EPU Evaluation: The EPU evaluation have confirmed adequate shutdown margin during the cooldown and xenon transient after an Appendix R event with no more than 55 gpm charging flow, including RCP seal leakage for a bounding 18 month fuel cycle.

In conclusion, calculations/evaluations listed in Table 2-4 of the SSAR, in support of the time-critical and functionally required tasks have been reviewed. This review concluded that time limits with respect to the critical tasks are still within the existing limits and have not been affected by the EPU.

Evaluation of Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The fire protection program attributes and system components that are within the scope of license renewal are addressed in License Renewal SER, NUREG-1839 Section 2.3.3.6, Fire Protection Systems (Reference 1), and SER Section 3.0.3.2.10, Fire Protection Program. These sections address aging management of the fire protection system and associated components. Fire barrier materials are addressed as a commodity group, while walls, floors, doors, structural steel etc., are evaluated within the building that contains them. Components credited with achieving safe shutdown following a fire are evaluated within the system that contains them.

The License Renewal SER states that the Fire Protection Program is consistent with, but includes exceptions to NUREG-1801, Generic Aging Lessons Learned (GALL) Report (Reference 2). The SER addresses exceptions taken by PBNP to the GALL Report. The NRC concluded that for those portions of the program which PBNP stated were consistent with the GALL program are consistent with GALL, and that, with regard to exceptions taken to the GALL program, PBNP had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained. Based on the uprate evaluation of elements of the fire protection program in this section, the EPU does not affect the evaluation/conclusions in the License Renewal SER regarding the fire protection program, and no new aging effects requiring management are identified.

Results

EPU does not affect the fire protection program. The EPU does not affect the elements of the fire protection program related to administrative controls and fire protection responsibilities of plant personnel.

The EPU does not affect the minimum set of pre-EPU safe shutdown systems/components, including cables, credited with achieving safe shutdown using either preferred or alternative capabilities.

The EPU does not affect the alternate shutdown methods. The EPU does not modify the function of any mechanical component in the alternative safe shutdown flow paths or introduce plant equipment failure modes which will affect the ability to achieve any of the alternative shutdown functions except for the AFW reconfiguration modifications described in LR Section 2.5.4.5, Auxiliary Feedwater. The existing plant modification process ensures that EPU design changes will not adversely affect existing Fire Protection Program requirements. The EPU does not adversely affect any components or circuits that provide power, control or indication to components required for alternative safe shutdown.

The capability to achieve cold shutdown conditions within 72 hours after reactor shutdown continues to be met for EPU conditions.

2.5.1.4.3 Conclusions

PBNP has assessed the fire-related safe shutdown and concludes that the assessment has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. PBNP further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and PBNP GDC 4 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to fire protection.

2.5.1.4.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2 NUREG-1801, Generic Aging Lessons Learned (GALL) Report, dated September 2005

3 NRC Generic Letter (GL) 86-10, Implementation of Fire Protection Requirements, April 24, 1986

2.5.2 Pressurizer Relief Tank

2.5.2.1 Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel that condenses and cools the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to accept discharge fluid from the pressurizer relief valve during a specified step-load decrease. The PRT is not safety-related and is not designed to accept a continuous discharge from the pressurizer. PBNP conducted a review of the PRT to ensure that operation of the tank at EPU conditions is consistent with transient analyses of related systems, and that failure or malfunction of the PRT will not adversely affect safety-related structures, systems, and components (SSCs). PBNP's review focused on any design changes related to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the EPU that are not bounded by previous analyses. 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 pressurizer PORVs and safety valves, 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 NRC's acceptance criteria for the PRT are based on:

- GDC 2, insofar as it requires that structures, systems, and components important-to-safety be designed to withstand the effects of earthquakes
- GDC 4, insofar as it requires that structures, systems, and components important-to-safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles

Specific review criteria are contained in the SRP Section 5.4.11.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 2 and 4 are as follows:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

As described in FSAR Section 4.1, Reactor Coolant Systems, Design Basis, all piping, components, and supporting structures of the Reactor Coolant System are designed as Seismic Class I equipment.

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

Conformance to the requirements of PBNP GDC 40 ensuring that safety-related SSC's of the reactor coolant system are adequately protected from internally generated missiles is discussed in FSAR Section 4.1, Reactor Coolant Systems, Design Basis.

The PRT is further discussed in FSAR Section 4.2, Reactor Coolant Systems, RCS System Design and Operation.

In addition to the evaluations described in the FSAR, the PRT was evaluated for plant license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The PRT itself is not within the scope of License Renewal. The programs used to manage the aging effects associated with Non-Class 1 RCS components are discussed in Section 3.1 of the SER.

2.5.2.2 Technical Evaluation

2.5.2.2.1 Introduction

The pressurizer safety valves are required to have adequate capacity to ensure that the RCS pressure does not exceed 110% of system design pressure. This is the maximum pressure allowed by the ASME Code (Section III, NB-7300 and NC-7300) for the worst-case loss of heat sink event, that is, the loss of external electrical load. The design of the surge line, safety valve inlet piping and safety valve discharge piping (including the PRT sparger pipe) are also based on the safety valve design capacity.

The PORVs are required to have adequate capacity to prevent pressurizer pressure from reaching the high-pressure reactor trip set point for an external load reduction of up to 50% of rated electrical load.

The PRT design (including the tank level setpoints) is also based on the total safety valve capacity and conservatively sized to condense and cool a discharge of pressurizer steam equal to 110% of the pressurizer steam volume above the original full-power pressurizer water level set point. This sizing basis was selected to ensure the tank could accept the discharge from the pressurizer safety valves following the worst case loss of external load transient. The PRT is equipped with a rupture disc that has a relief capacity in excess of the combined capacity of the pressurizer safety valves.

The tank normally contains water in a predominantly nitrogen atmosphere. The volume of nitrogen gas in the tank is selected to limit the maximum pressure to 50 psig following a design discharge. The volume of water in the tank is selected to limit the maximum temperature to 200°F following a design discharge. The PRT level set points ensure adequate coolant is maintained in the tank to condense and cool the design bases discharge, and to preclude the tank temperature and pressure from exceeding 200°F and 50 psig, respectively.

2.5.2.2.2 Description of Analyses and Evaluations

The PRT was evaluated based on the results of the loss of external load analysis described in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum. The analysis was performed for the range of NSSS design parameters listed in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. The evaluation was performed for an analyzed NSSS thermal power of 1816.8 MWt which includes 0.6% core power uncertainty.

The results of the loss of electrical load analysis confirmed that the installed capacity of the pressurizer safety valves is adequate to preclude RCS overpressurization at EPU conditions. Since the design of the surge line, safety valve inlet piping, safety valve discharge piping, PRT, PRT rupture disc, and sparger pipe are based on the capacity of the pressurizer safety valve capacity, it can be concluded these components are also adequate for EPU conditions.

In addition, the loss of external electrical load transient analysis for EPU determined that the mass and energy of the steam discharged from the pressurizer into the PRT is less than the design bases discharge. Since the current PRT level setpoints ensure adequate coolant is maintained in the tank to condense and cool the design bases discharge these setpoints remain adequate to preclude the tank temperature and pressure from exceeding 200°F and 50 psig, respectively, at EPU conditions. The mass of coolant currently maintained in the PRT exceeds by 16% the mass of coolant required for the worst case loss of external load transient at EPU conditions.

The PORVs are required to have adequate capacity to prevent pressurizer pressure from reaching the high-pressure reactor trip set point for an external load reduction of up to 50% of rated electrical load. A margin to trip analysis was performed based on the range of NSSS design parameters for EPU listed in LR Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. The results of this analysis are described in LR Section 2.4.2, Plant Operability. These analyses confirmed that the installed capacity of the PORVs is adequate to preclude a high-pressurizer pressure reactor trip at EPU conditions. Based on these results, it can also be concluded that the design of the inlet and discharge piping of the PORVs is adequate at EPU conditions, since the design of this piping is based on the design capacity of the PORVs. The mass and energy addition to the PRT during load rejection is not limiting with respect to the design and operating set points for the PRT, since this transient discharge is less severe than the loss of external electrical load transient discharge.

Since the current design basis for the PRT bounds the EPU loss of external load analysis mass and energy addition, without any changes in the PRT set points, it can also be concluded that the current design basis for the PRT interface support functions are not impacted by the EPU. These support functions include reactor makeup for cooling, nitrogen for pressure control, gas analyzer connection for periodic sampling, and means to vent and drain the tank.

LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports, and LR Section 2.5.1.3, Pipe Failures, evaluated the piping and supports for the PRT relative to meeting the PBNP current licensing basis requirements with respect to PBNP GDC-2 and PBNP GDC-40. These PBNP GDC address protection of structures, systems and components following design basis events that may result in failure of the non-safety grade PRT. Since the original design bases for the PRT and associated piping remain bounding at EPU conditions, the current PBNP licensing basis requirements remain satisfied for EPU.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

EPU activities do not add any new functions for the existing component that would change the license renewal evaluation boundaries. The changes associated with operating the PRT at EPU conditions do not add any new or previously unevaluated aging effects that would necessitate a change to aging management programs or require a new program, as internal and external environments remain within the parameters previously evaluated. Therefore, there is no impact to license renewal scope, aging effects, and aging management programs due to EPU activities.

2.5.2.3 Results

Based on the results of the evaluations described in LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum and LR Section 2.4.2.2, Pressurizer Control Component Sizing, the current design basis for the PRT, PRT rupture disk, PRT sparger, surge line, PORV and safety valve inlet piping, and PORV and safety valve discharge piping remains acceptable for a loss of electrical load at EPU conditions. In addition, the current PRT design bounds the EPU loss of external load analysis mass and energy addition such that, following implementation of EPU, the PRT continues to meet its design basis mass and energy addition without any changes in the PRT level or pressure set points. The mass of coolant currently maintained in the PRT exceeds by 16% the mass of coolant required for the worst case loss of external load transient at EPU conditions.

The evaluations described in LR Section 2.4.2.2, Pressurizer Control Component Sizing and LR Section 2.5.1.3, Pipe Failures, determined the piping and supports associated with the PRT remain adequate for EPU conditions relative to satisfying the PBNP current licensing basis requirements.

2.5.2.4 Conclusions

PBNP has reviewed the pressurizer discharge to the PRT as a result of the EPU and concludes that the PRT will continue to operate in a manner consistent with transient analyses of related systems. Structures, systems, and components will continue to be protected against the failure of the PRT consistent with PBNP GDC 2 and 40 with respect to the current PBNP licensing basis. Therefore, PBNP finds the EPU acceptable with respect to the design of the PRT.

2.5.2.5 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

2.5.3.1.1 Regulatory Evaluation

The PBNP review for fission product control systems and structures covered the basis for developing the mathematical model for design basis LOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of the ventilation systems used to control fission product releases. PBNP's review primarily focused on any adverse effects the proposed EPU may have on the assumptions used in the analyses for control of fission products.

The NRC's acceptance criteria are based on

- GDC 41, insofar as it requires that the containment atmosphere cleanup system be provided to reduce the concentration of fission products released to the environment following postulated accidents.

Specific review criteria are contained in Standard Review Plan (SRP) Section 6.5.3.

PBNP Current Licensing Bases

As noted in PBNP Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC). PBNP has no plant-specific PBNP GDC equivalent to Appendix A, GDC-41.

Not yet included in FSAR is the submittal for the Alternative Source Term (AST) LAR 241, (ML083450683). The EPU dose calculations use the methodology contained in the AST submittal.

In-Containment Recirculation System

The current radiological analyses and pending LR 241 assume that the air volume in the containment building is mixed by the containment fan coolers to support the iodine removal function performed by the containment spray system. The containment air recirculation cooling (VNCC) system is discussed in LR Section 2.6.5, Containment Heat Removal.

In-Containment Iodine Removal System

The current radiological analyses assume that the containment spray system operates in the injection phase of the accident to remove iodine from the containment atmosphere. The radiological analyses associated with LR 241 assume that the containment spray system operates to remove iodine from the containment atmosphere in the injection phase and the recirculation phase of the accident, with a maximum 20-minute interruption for the purposes of aligning the containment spray system for recirculation spray.

The containment spray system delivers a sodium hydroxide solution into the spray stream to remove iodine. The system includes a common sodium hydroxide tank that contains enough sodium hydroxide solution which, upon mixing with the refueling water from the refueling water storage tank during the injection phase, and the borated water contained within the accumulators and primary coolant that collect in the containment sump during the recirculation phase, to maintain the pH within a range of 7.0 to 10.5. A pH of greater than 7.0 assures the iodine removal effectiveness of the containment spray. The maximum pH is based on equipment qualification considerations and is set at 10.5.

The in-containment iodine removal function of the containment spray system is discussed in FSAR Section 6.4, Engineered Safety Features, Containment Spray System and Appendix C.1, Purpose of Chemical Addition to Containment Spray.

Control Room Ventilation (VNCR) System

The radiological analyses associated with the pending License Amendment Request for Implementation of Alternative Source Term assume the VNCR system operates with filtered return air in addition to filtered makeup air. This configuration is referred to as Mode 5 (emergency HEPA/charcoal filtered outside air and HEPA/charcoal filtered return air mode). The Control Room Ventilation System (VNCR) is discussed in LR Section 2.7.1, Control Room Habitability System, LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup, and LR Section 2.7.3, Control Room Area Ventilation System.

License Renewal

In addition to the evaluations described in the FSAR, the above systems were evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

The SER discusses the Containment Spray System in Section 2.3.2.2, the VNCC in Section 2.3.3.9, and VNCR in Section 2.3.3.10.

2.5.3.1.2 Technical Evaluation

The Containment Spray System and the Containment Air Recirculation Cooling System (VNCC) are designed to reduce containment pressure and the fission product concentration in the containment atmosphere following a LOCA.

These systems limit the release of fission products from the containment by:

- Reducing the fission product concentration in the containment atmosphere by spraying chemically treated borated water which removes airborne elemental iodine vapor by washing action
- Reducing the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment

The Containment Spray System consists of two independent trains. Each train consists of a pump, spray header, and associated piping and valves. Each train is designed to deliver 1200 gpm of borated water from the Refueling Water Storage Tank (RWST) into the containment atmosphere during the injection phase following a LOCA. Following the injection phase the Containment Spray System in conjunction with the RHR System may be used to continue to provide spray flow to the containment.

The Containment Air Recirculation Cooling System (VNCC) consists of four fan cooler units and associated duct distribution system. Each fan cooler consists of a roughing filter, cooling coil, and two fans and motors. One fan and motor per cooling unit are designed for the high pressure, temperature and density following a LOCA and one fan and motor per cooling unit are designed for normal operation and are not required to operate under LOCA conditions.

The Control Room Ventilation System (VNCR) is designed to provide heating, ventilation, air conditioning, and radiological habitability for the control and computer rooms. The radiological analyses associated with the pending License Amendment Request for Implementation of Alternative Source Term assume the VNCR system operates with filtered return air in addition to filtered makeup air. The VNCR is discussed in LR Section 2.7.1, Control Room Habitability System, LR Section 2.7.2, Engineered Safety Feature Atmosphere Cleanup, and LR Section 2.7.3, Control Room Area Ventilation System.

The offsite and control room dose analyses, presented in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, (including LOCA, SGTR, MSLB, LR, CRDE, FHA and RVHD), demonstrate the effectiveness of the Containment Spray System and the VNCC to minimize the release of radioactivity to the environment following a LOCA.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The Containment Spray System, VNCC and the VNCR are within the scope of License Renewal. Aging Management Programs are addressed in the NUREG-1839 License Renewal SER Section 3.2.2.3.3, Containment Spray System, Section 3.3.2.3.9, Containment Ventilation System, and Section 3.3.2.3.10, Essential Ventilation System, respectively. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified as a result of EPU.

Results

The effect of EPU on fission product control is an increase in source term, which is considered in the new LOCA dose analysis discussed in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Term (including LOCA, SGTR, MSLB, LR, CRDE, FHA, and RVHD). A review of this section indicates that the Containment Spray System, VNCR and the VNCC, in conjunction with other systems, structures and components, are effective in limiting both Control Room and off-site dose to within regulatory guidelines.

2.5.3.1.3 Conclusions

PBNP has assessed the effects of the proposed EPU on fission product control systems and structures. The EPU dose calculations prepared as part of this assessment use the methodology contained in the LAR 241 submittal for the Alternative Source Term currently under review. PBNP has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed EPU. PBNP further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in post accident environments following implementation of the proposed EPU. Based on this, PBNP also concludes that the fission product control systems and structures will continue to meet the current licensing basis. Therefore, PBNP finds the proposed EPU acceptable with respect to the fission product control systems and structures

2.5.3.1.4 References

1 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.3.2 Main Condenser Evacuation System

2.5.3.2.1 Regulatory Evaluation

The Main Condenser Evacuation System (MCES) generally consists of two subsystems: (1) or startup system which initially establishes main condenser vacuum and (2) the system which maintains condenser vacuum once it has been established. The PBNP review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists).

The NRC's acceptance criteria for the main condenser evacuation system are based on:

- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.
- GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents.

Specific review criteria related to these GDC are contained in SRP Section 10.4.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-60 and 64 are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

The condenser air ejector exhaust, which is one of the effluent discharge paths, is monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation is indicated and alarmed in the control room.

Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the use of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), are contained in the Technical Specification (TS) 5.5.4, Radioactive Effluent Controls Program, TS 5.5.1, Offsite Dose Calculation Manual, TRM 4.1, PBNP Offsite Dose Calculation Manual (ODCM) and TRM 4.4, Radioactive Effluent Controls Program.

The adequacy of the PBNP condenser evacuation system design relative to control of the release of radioactive material from steam in the turbine to the environment is provided in LR Section 2.5.6.1, Gaseous Waste Management Systems.

The PBNP condenser evacuation system is discussed in FSAR Sections 6.5, Leakage Detection Systems, 10.1, Steam and Power Conversion System, 11.2, Gaseous Waste Management System, 11.5, Radiation Monitoring System, and Appendix I, 10 CFR 50, Appendix I Evaluation of Radioactive Releases From Point Beach Nuclear Plant.

As a part of the main and auxiliary steam, and feedwater and condensate systems, the condenser evacuation system components were evaluated and determined to be not in scope for plant License Renewal.

2.5.3.2.2 Technical Evaluation

Introduction

The MCES is discussed in the FSAR Section 10.1, Steam and Power Conversion System.

The system is divided into two subsystems; the Vacuum Priming System and the Condenser Air Removal System.

The Vacuum Priming System removes air and non-condensables from the condenser waterboxes. It consists of a vacuum control tank and two motor-driven vacuum pumps. The vacuum priming system discharges the air and non-condensables to the atmospheric blow-off tank. The additional released air to the waterbox due to the increased T_{rise} across the condenser due to EPU is small and the effect on the capacity of the existing Vacuum Priming System is not significant.

The Condenser Air Removal System consists of priming ejectors and the two-stage air ejectors. The Condenser Air Removal System extracts air, non-condensables and water vapor from the condenser at four inter-condenser connections and two after-condenser connections and discharges air and non-condensables to the atmosphere.

The priming ejector subsystem consists of two single-stage steam jet air ejectors and evacuates non-condensable gases from the condenser during start up. It discharges through the roof of the turbine building.

The two-stage air ejector system consists of four first-stage air ejectors and two second-stage air ejectors and is used with the priming ejectors during startup to establish condenser vacuum. During normal operation the two-stage ejectors maintain condenser vacuum. The two-stage air ejector system discharges through the air removal decay duct system.

The Vacuum Priming System can also be used in the initial evacuation of the condenser. The tie between the vacuum priming subsystem and the condenser air removal subsystem is piping that runs from upstream of each priming ejector to the vacuum control tank. These lines are normally valved closed.

The MCES must have sufficient capacity to facilitate plant startup and maintain condenser vacuum at all plant operating loads by removing all non-condensable gases and air in-leakage to the condenser.

Description of Analyses and Evaluations

The Condenser Air Removal System must be capable of removing non-condensable gases and air in-leakage from the condenser shell (steam space) to maintain vacuum. Air in-leakage will not be adversely affected by the EPU since air in-leakage is entirely related to the physical design of the condenser and its state of integrity. In addition, any existing air in-leakage may be slightly reduced due to the higher condenser backpressure at EPU. Therefore, the Condenser Air Removal System is evaluated by comparing its removal capability with the expected increase in non-condensable flow resulting from the increased low pressure turbine exhaust flow rate at EPU conditions. Refer to LR Section 2.5.5.2, Main Condenser, for additional discussion related to the condenser.

The two-stage air ejector system maintains a vacuum in the condenser. The two-stage air ejector has four first stage elements, which are mounted on the shell of the inter-condenser, and two second stage elements, which are mounted on the shell of the after-condenser. The ejectors are supplied with steam from the main steam system. The four element set of two-stage steam jet air ejectors (SJAE) have a rated capacity of 30 scfm (7.5 scfm each SJAE). The air removal capability was compared to the recommended removal capacity from Heat Exchange Institute Standards for Steam Surface Condensers and to actual measurements of air ejector flow rate.

The condenser air ejector exhaust is monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation levels are indicated and alarmed in the control room. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for the evaluation of plant radioactive monitoring and control of releases of radioactive materials to the environment in compliance with PBNP GDC 17. For gaseous radioactive material handling refer to LR Section 2.5.6.1, Gaseous Waste Management Systems.

Since there is no potential for explosive gas mixtures in the condenser, it was not included in the evaluation.

Results

The condenser air removal rate will increase from a current rate of 3.9 scfm to approximately 4.6 scfm at EPU. The higher EPU removal rate remains less than the design capacity of the air ejectors. Therefore, the existing Air Ejector System is adequate for EPU without modifications.

The two priming ejectors and the two-stage ejectors evacuate non-condensable gases from the condenser during startup. Since startup conditions do not change due to EPU operation, these ejectors are adequate for establishing condenser vacuum at EPU conditions.

The Vacuum Priming System evacuates non-condensables from the waterboxes. The additional air released to the waterbox due to the increased temperature rise across the condenser is negligible. Since the circulating water system is not being modified for EPU, the effect on the capacity of the existing Vacuum Priming System will be insignificant at EPU.

The design of the MCES does not change following the implementation of the EPU. Therefore, the EPU does not impact the ability of PBNP to control radioactive material or the monitoring of radioactive material releases. The impact of EPU on radiological effluent releases from PBNP and compliance with 10 CFR 50, Appendix I, is discussed in LR Section 2.10.1, Occupational and Public Radiation Doses.

2.5.3.2.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the Main Condenser Evacuation System and concludes the system's capability to remove non-condensable gases from the condenser during start up and normal operation remains adequate. PBNP also concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU in accordance with PBNP GDC 17 and 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the Main Condenser Evacuation System

2.5.3.2.4 References

None

2.5.3.3 Turbine Gland Sealing Systems

2.5.3.3.1 Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. PBNP reviewed changes to the turbine gland sealing system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths).

The NRC's acceptance criteria (10 CFR 50, Appendix A) for the Turbine Gland Sealing System are based on:

- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents into the environment.
- GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents.

Specific review criteria are contained in SRP Section 10.4.3.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-60 and 64 are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether solid, liquid, or gaseous. Appropriate holdup capacity shall be provided for retention of solid, liquid, or gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

The turbine gland sealing system is described in FSAR Section 10.1, Steam and Power Conversion. The turbine gland sealing system prevents air leakage into the turbine casing that could increase turbine windage losses and reduce condenser vacuum. It also prevents steam leakage from the turbine casing into the turbine building.

As part of the turbine generator and supporting systems, the turbine gland sealing system was evaluated and determined not in scope for plant License Renewal.

2.5.3.3.2 Technical Evaluation

Introduction

The Turbine Gland Sealing System prevents air leakage into the turbine casing and prevents steam leakage from the turbine casing into the turbine building. In the postulated event of a steam generator tube failure, the Turbine Gland Sealing System would prevent the spread of contaminants into the turbine building. The turbine rotor is designed with labyrinth type glands/seals which provide a high resistance to steam or air flow along the shaft. Gland sealing steam is provided to the gland seal chamber to maintain a slight positive pressure under all operating conditions. Excess steam leaks off from the gland and is collected in the gland steam condenser. Condensed steam drains from the gland steam condenser to the main condenser.

For plant startup, sealing steam is initially supplied from an external source, main steam. As the turbine load is increased, the turbine steam pressure increases and leakage from the high-pressure turbine glands and steam from the regulator valve supplies the steam sealing requirements for the low pressure turbine glands.

The gland steam condenser maintains a pressure slightly below atmospheric in the gland leakage system to prevent the escape of steam from the glands to the turbine building. The gland steam condenser liquefies the steam vapor to recover its energy. The condensed steam is drained to the main condenser. Cooling of the gland steam condenser is provided by the condensate system. The entrained air and other non-condensable vapors leaving the gland steam condenser are discharged through an atmospheric vent by an air exhauster. A radiation monitor is provided on the discharge vent pipe to monitor radiation levels of effluent prior to being released to the environment.

Description of Analyses and Evaluations

The turbine gland sealing system was evaluated to ensure that the system design will continue to control the release of radioactive material from steam in the turbine to the environment, and continue to provide sufficient sealing steam to the high pressure and low pressure turbine glands from plant start-up through full power operation at EPU conditions. This evaluation also determines whether changes are required to the existing design of the system and its components in order to meet their design functions during EPU conditions, and whether such changes affect the system's ability to control radioactive releases.

Evaluation of Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

In regard to the aging programs and aging influences described in the License Renewal SER NUREG 1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, the Gland Seal System was evaluated and it was concluded that this system was not in scope of the License Renewal. Thus, no new aging effects due to EPU requiring management were identified.

Results

The gland sealing steam supply flow to the low pressure turbine gland seals is made up of auxiliary/main steam and HP turbine gland leakoff steam. The HP turbine rotor is being replaced to support EPU operation, and the pressure in the modified HP turbine gland seal leakoff area increases. At EPU, the leak-off flow from the HP turbine will exceed the flow required by the low pressure turbine glands. Modifications may be needed to ensure the proper operation of the low pressure turbine gland seals. Necessary changes will be addressed as part of the HP turbine modification process.

There is no increase in the required external steam supply flow from the main steam system since it is primarily used to supply sealing steam for turbine/plant startup and at reduced power operation. As plant power increases, the amount of main steam flow required for gland sealing decreases. Therefore, it is not affected by the EPU.

The increase in steam flow to the gland steam condenser due to the EPU is small. Consequently, there is a small change in the air and non-condensable exhaust flows exiting the gland steam condenser due to the EPU. In the event of a postulated steam generator tube failure, sealing steam to the gland seal will maintain system integrity by preventing contaminated steam from escaping the turbine pressure boundary. Existing stack effluent radiation monitoring equipment that measures effluent levels based on allowable limits will not be impacted by EPU, as discussed in LR Section 2.10.1, Occupational and Public Radiation Doses.

The high pressure (HP) turbine gland steam leakoff flow increases due to the increased high pressure turbine exhaust pressure associated with the EPU. This increased leak-off flow is then used to supply sealing steam to the low pressure turbines. Since the pressure within the high pressure turbine increases, the leakoff flow from the high pressure turbine exceeds the flow required by the low pressure turbine glands. Modifications may be needed to ensure the proper operation of the low pressure turbine gland seals and will be determined as part of the HP turbine modification process. No physical changes are required to the turbine gland sealing components due to the changes in steam and water flows associated with the EPU. In the event of a postulated steam generator tube failure, sealing steam to the gland seal will maintain system integrity by preventing contaminated steam from escaping the turbine pressure boundary.

The increase in sealing steam flow and cooling water flow raises the velocities in the piping. The potential for increased erosion/corrosion is discussed in LR Section 2.1.8, Flow-Accelerated Corrosion. Necessary changes to the subject piping will be addressed as part of the HP turbine modification process.

The replacement of the condensate pumps for EPU increases the condensate flow through the gland seal condenser. The increased flow will not affect the capability of the gland seal condenser since the pressure in the gland supply header is not increasing for EPU.

The evaluation of the turbine gland sealing system at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the EPU. The handling, control, and release of radioactive materials continue to be in compliance with PBNP GDC 70.

The evaluation of the turbine gland sealing system at EPU conditions demonstrates that it will continue to meet the current licensing basis, insofar as it requires that a means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and postulated accidents. Modifications that may be needed to ensure the proper operation of the low pressure turbine gland seals will be addressed as part of the HP turbine modification process. This design capability remains unchanged by the EPU. Radioactivity levels contained in the effluent discharge paths in the environs are continually monitored during normal and accident conditions by the station radiation monitoring system and by the radiation protection program for PBNP. (Refer to LR Section 2.10.1, Occupational and Public Radiation Doses)

2.5.3.3.3 Conclusions

PBNP has assessed the required changes to the Turbine Gland Sealing System for EPU conditions and concludes that the assessment has adequately evaluated these changes. PBNP concludes that the Turbine Gland Sealing System will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment consistent with the current licensing basis requirements of PBNP GDCs 17 and 70. Therefore, the PBNP finds the proposed EPU acceptable with respect to the Turbine Gland Sealing System.

2.5.3.3.4 References

None

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling and Cleanup System

2.5.4.1.1 Regulatory Evaluation

The spent fuel pool provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The PBNP review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions.

The NRC's acceptance criteria for the spent fuel pool cooling and cleanup system are based on:

- GDC 5, insofar as it requires that structures, systems, and components 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 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related structures, systems, and components 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 reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions.

Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

PBNP Current Licensing Bases

The spent fuel pool cooling system piping and the service water system piping supplying the spent fuel pool heat exchangers are classified Safety-Related, Seismic Class I.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-5, 44 and 61 are as follows:

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

The Spent Fuel Pool Cooling System, common to Units 1 and 2, is designed to remove decay heat from fuel assemblies stored in the common spent fuel pool after removal from the reactor vessel. A discussion of the sharing of the components of this system between the two units is given in FSAR Appendix A.6, Shared System Analysis.

CRITERION: Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which could result in undue risk to the health and safety of the public. (PBNP GDC 67)

As described in FSAR Section 9.9, Spent Fuel Cooling and Filtration, the Spent Fuel Pool Cooling System is designed to remove the decay heat produced by irradiated fuel assemblies stored in the spent fuel pool. When the storage capacity of the original pool was increased to its present capacity, the heat removal capability of the Spent Fuel Pool Cooling System was increased from its original capacity. The present fuel assembly storage capacity for the spent fuel pool is provided in FSAR Table 9.4-1, Fuel Handling Data.

The service water system is the heat sink for Spent Fuel Pool heat loads. The Spent Fuel Cooling System was sized to remove the refueling heat loads at the service water temperatures normally expected to occur during spring and fall refueling outages.

All piping and components of the spent fuel cooling system are designed to the applicable codes and standards listed in FSAR Table 9.9-1, Spent Fuel Pool Cooling System Component Data. Austenitic stainless steel piping is used in the Spent Fuel Pool Cooling System, for the piping to and from the pool. Piping is arranged so that a failure of any one pipe will not drain the water in the spent fuel pool below the top of the fuel elements.

Core Off-Load Time vs. Lake Temperature

The required time after shutdown prior to initiating an offload of the core is dependent upon the available lake temperature. As stated in FSAR Section 9.6, Service Water System, the highest normally expected service water inlet temperature is 75°F. It is noted that for an offload, the decay heat load is calculated prior to each refueling. This is to ensure the decay heat load for a given time after shutdown is within the capability of the Spent Fuel Cooling System.

The nominal heat load imposed on the system from a normal refueling is 11.5 million Btu/hr. This is based on an assumption of a one third core offload to fill the pool after a nominal 10-day decay period. One train of the SFP Cooling System is capable of removing this heat load and maintaining SFP temperature below 120°F under nominal conditions.

The maximum heat load assumed by the design is that resulting from offloading a complete core that has been operated for about 30 days. The combined heat removal capability of the SFP Cooling System (31.0 million Btu/hr) is capable of removing this heat load and maintaining SFP temperature at or below 120°F under nominal conditions. The capacity of one train of SFP cooling is capable of removing this heat load and maintaining SFP temperature at or below 145°F.

Operations	Pool Heat Load BTU/hr	Heat Removal Capability BTU/hr	Number of Cooling Trains Operating	Maximum Fuel Pool Operating Temperature (°F)
Accumulation from normal refueling cycles (1502 assemblies)	11.5×10^6	15.5×10^6	1	120
Removal of entire core (1381 assemblies + core unload)	23.9×10^6	31.0×10^6	2	120

Assuming a loss of SFP cooling in the worst case conditions of a full core offload completed within 150 hours following reactor shutdown and an initial SFP temperature of 120°F, the time-to-boil is approximately 11 hours. This is sufficient time for plant personnel to take corrective actions to establish a means of spent fuel pool cooling.

Fuel Pool Re-Racking

In 1975, the spent fuel pool was reracked and the total fuel storage capability was raised to 351 assemblies. Shortly thereafter (in 1977), a new spent fuel pool cooling system was installed to reduce the extended delays during core offloads (required until fuel decay heat was within the capability of the existing system). This new system was capable of a higher heat removal capacity, and also included increased system redundancy with two 100% Spent Fuel Pool Pumps and two 100% Spent Fuel Pool Heat Exchangers.

The pool was reracked again in 1979 to raise the total pool storage capability to 1502 storage locations, but did not require increases in the Spent Fuel Pool Cooling System cooling capacity. An upgrade of the Spent Fuel Pool Cooling System to safety-related status in 1987 also did not require configuration changes.

Other Design Features

FSAR Section 9.6, Service Water System, describes the cooling water provided to the spent fuel pool heat exchangers.

The PBNP spent fuel pool area ventilation system is non-safety related, and no credit is taken for removal of iodine by the spent fuel pool ventilation system nor is credit taken for isolation of release paths. The spent fuel pool area ventilation is discussed in LR Section 2.7.4.1, Spent Fuel Pool Area Ventilation System Regulatory Evaluation.

License Renewal

In addition to the evaluations described in the FSAR, the Spent Fuel Pool Cooling System was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 2)

With respect to the above SER, the Spent Fuel Pool Cooling System is described in Section 2.3.3.3, Spent Fuel Cooling System. Aging effects, and the programs used to manage the aging effects associated with the Spent Fuel Pool Cooling System, are discussed in Section 3.3.2.3.4.

2.5.4.1.2 Technical Evaluations

Introduction

The Spent Fuel Pool Cooling System, common to Units 1 and 2, is designed to remove decay heat from fuel assemblies stored in the spent fuel pool (common to both units), remove ionic impurities from the spent fuel pool water, and maintain pool surface clarity by means of a small flow from the surface of the pool. These performance requirements are directly related to both Spent Fuel Pool Cooling System safety and non-safety functions.

The Spent Fuel Pool Cooling System consists of two separate cooling trains, with a common suction and return header, each having an identical heat exchanger and pump. Cooling is normally provided by one cooling train with the other train being available as a backup in the event of a failure. Water from the spent fuel pool is pumped through one or both heat exchangers for cooling and returned to the pool. When purification is required, a portion of the flow is diverted through the interconnecting spent fuel pool purification system. Service water provides the heat exchange medium for removal of decay heat.

The heat removal criteria of the Spent Fuel Pool Cooling System are that the system should be:

- capable of maintaining the temperature in the Spent Fuel Pool less than or equal to 120°F during normal refueling operations with one cooling loop in operation
- capable of maintaining the temperature in the Spent Fuel Pool less than or equal to 120°F following a full core offload with two cooling loops in operation
- capable of maintaining the temperature in the Spent Fuel Pool less than or equal to 145°F following a full core offload with one cooling loop in operation.

Normal refueling operations are conducted approximately every 18 months for each unit. The pool temperature is evaluated based on decay heat generation from a full core offload (121 fuel assemblies) that fills the fuel pool (1502 fuel assemblies) and on decay heat from normal refuelings resulting in a full Spent Fuel Pool. Decay heat loads are also calculated prior to each refueling to confirm the decay heat load for a given time after shutdown is within the capability of the Spent Fuel Pool Cooling System at the current service water temperature.

The Spent Fuel Pool temperature and water level are monitored with alarms in the Control Room to alert operators to a potential system malfunction. The Spent Fuel Pool cooling system flow is monitored locally to alert operators to unexpected changes in flow.

EPU will result in higher heat loads in the Spent Fuel Pool as a result of the fuel being irradiated at a higher power level and additional number of fuel assemblies per reload. The ability of the system to handle the increase in heat load needs to be evaluated.

Description of Analyses and Evaluations

The Spent Fuel Pool Cooling System and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation was performed for an analyzed core thermal power of 1800 MWt. It is noted that no changes to system flows, pressures or temperatures are required due to EPU. The evaluations determined whether the existing design parameters of the Spent Fuel Pool Cooling System and components meet the EPU conditions for the following design aspects:

- Design pressure/temperature of piping and components
- Flow velocities
- Cooling capacity – Normal Refueling Conditions
- Cooling capacity – Maximum Design Conditions (Full Core Offload)
- Loss of cooling
- Concrete wall temperature
- Purification subsystem

Other evaluations related to the Spent Fuel Pool Cooling System and components are addressed in the following Licensing Report (LR) sections:

- Piping/component supports – Section 2.2.2.2, Balance of Plant Piping, Components, and Supports
- Protection of the Spent Fuel Pool Cooling System from internally generated missiles – Section 2.5.1.2, Missile Protection
- Service Water cooling water for spent fuel pool heat exchangers – Section 2.5.4.2, Station Service Water System
- Protection against dynamic effects of missiles, pipe whip and discharging fluids – Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures
- Fuel pool ventilation and control of airborne radioactivity – Section 2.7.4, Spent Fuel Pool Area Ventilation System
- Fuel pool criticality, fuel movement and storage; evaluation of the storage racks – Section 2.8.6.2, Fuel Storage

System/Component Design Parameters

No modifications to the Spent Fuel Pool Cooling System are required for EPU to comply with PBNP's existing regulatory commitments.

The current Spent Fuel Pool Cooling System design pressure and temperature are 150 psig and 200°F, respectively. The maximum operating conditions at EPU do not change, including the maximum spent fuel pool temperature during cooling system operation of 145°F. The only time the maximum pool temperature of 145°F may be exceeded is during a complete loss of all spent fuel pool cooling. Therefore, the existing design pressure and temperature of the system components (heat exchangers, pumps, valves, demineralizers, strainers, and filters) are acceptable at EPU.

The current spent fuel pool cooling flow rate provides for acceptable heat removal in the spent fuel pool heat exchangers. Therefore, no changes are required to the fuel pool cooling pumps/motors and the system piping velocities are unchanged at EPU conditions.

Cooling Capacity – Normal Refueling

The Spent Fuel Pool is common to both units. Each unit undergoes a normal refueling outage approximately every 18 months, is based upon removal of approximately one-third (41 assemblies) of the 121 reactor fuel assemblies. The Spent Fuel Pool holds a total of 1502 fuel assemblies. For EPU operation the projected number of assemblies to be removed during a normal refueling outage will increase to 49 assemblies. The Spent Fuel Pool heat load and the ability of the system to handle this heat load is procedurally evaluated prior to each refueling. The heat load resulting from the outage is calculated based on decay time, power history, and inventory from previous outages. This calculated heat load is compared to both the bounding decay heat load and the ability of the Spent Fuel Pool Heat Exchangers based on the current Service Water temperature to ensure the outage load is within the capability of the system.

The current normal refueling heat load of 11.5×10^6 Btu/hr is calculated based on a full pool of 1502 fuel assemblies as a result of normal refuelings. The refueling outage that results in a full pool is considered to occur three months after the last regular refueling with a decay period of 10 days. At the EPU power level of 1800, MWt, the corresponding heat load is calculated to be 14.7×10^6 Btu/hr. The heat load is calculated using the methods found in ANSI/ANS-5.1-1979 (Reference 1) and assumes that all of the fuel assemblies have been irradiated at the EPU power level of 1800 MWt. Assuming all of the fuel assemblies have been irradiated at 1800 MWt is conservative and results in a bounding heat load calculation since fuel stored in the pool prior to EPU implementation has been irradiated at a lower power level. The analysis assumes that the oldest fuel assemblies with the least amount of decay heat will be removed from the pool and sent to dry storage first. Eventually, as older spent fuel is removed from the pool and placed in dry storage, the fuel stored in the pool will all have been irradiated at 1800 MWt. This calculated normal heat load at EPU power is within the 15.5×10^6 Btu/hr nominal design capacity of one heat exchanger for maintaining the pool at 120°F with 65°F service water.

The required offload delay time after reactor shutdown based on the calculated Spent Fuel Pool Heat Exchanger capability considering tube plugging and fouling was also evaluated for normal refueling conditions. Table 2.5.4.1-1, Normal Refueling w/ Spent Fuel Pool @ 120°F, shows the minimum time required before offload can be performed after shutdown in order not to exceed the normal Fuel Pool temperature of 120°F for service water temperatures of 65°F and 80°F.

Cooling Capacity – Full Core Offload

The maximum heat load assumed by the system design is that resulting from offloading a complete core (121 assemblies) that has been operated for about 30 days with a 13-day decay period plus the decay heat from 1381 assemblies from normal refuelings, resulting in a full pool of 1502 assemblies. The Spent Fuel Pool heat load and the ability of the system to handle this heat load are procedurally evaluated prior to each refueling. The heat load resulting from the outage is calculated based on decay time, power history, and inventory from previous outages. This calculated heat load is compared to both the bounding decay heat load and the ability of the Spent Fuel Pool Heat Exchangers based on the current Service Water temperature to ensure the outage load is within the capability of the system.

The current full core offload decay heat load is calculated to be 23.9×10^6 Btu/hr. At the EPU power level of 1800 MWt, the maximum heat load as a result of a full core offload is calculated to be 24.6×10^6 Btu/hr. The heat load is calculated using the methods found in ANSI/ANS-5.1-1979 (Reference 1) and assumes that all of the fuel assemblies have been irradiated at the EPU power level of 1800 MWt. This calculated full core offload heat load at EPU power is within the 31.0×10^6 Btu/hr nominal design capacity of both heat exchangers for maintaining the pool at 120°F with 65°F service water.

The required offload delay time after reactor shutdown based on the calculated Spent Fuel Pool Heat Exchanger capability considering tube plugging and fouling was also evaluated for the full core offload refueling conditions. Table 2.5.4.1-2, Full Core Offload w/ Spent Fuel Pool @ 145°F[1], shows the minimum time required before offload can be performed after shutdown in order not to exceed the maximum Fuel Pool temperature of 145°F for service water temperatures ranging from 60°F to 80°F.

Cooling Capacity – Transition to EPU

In addition to calculating the Spent Fuel Pool heat loads based on the EPU power level, the Spent Fuel Pool heat loads during the transition to EPU operation were also calculated to ensure any interim conditions that may result in higher heat loads are also evaluated. This evaluation was based on the current pool inventory plus those assemblies added through the transition to EPU which result in a full pool of 1502 assemblies.

The transition to EPU involves four refueling outages (two for each unit) where 60 fuel assemblies are removed from the reactor and placed in the pool. The first refueling load of 60 fuel assemblies for each unit will have been operated at current power level of 1540 MWt and the second refueling load of 60 fuel assemblies for each unit will have been operated at the EPU power level of 1800 MWt. Subsequent EPU refueling outages will place 49 assemblies in the pool. The heat loads based on the existing pool inventory, the transition to EPU outages and several following outages were calculated. Each calculated transition heat load is compared to the heat load calculated for a pool full of EPU fuel for the respective scenario (from above, 24.6×10^6 Btu/hr for a full core offload and 14.7×10^6 Btu/hr for a normal offload). For the Full Core Offload scenario, each calculated transition heat load is bounded by the EPU heat load. For the Normal Refueling scenario the outage at the conclusion of the EPU transition period is

15.7×10^6 Btu/hr. This transition heat load is greater than the EPU load as a result of the two transition offloads of 60 assemblies at the EPU power level. The calculated delay times needed for this transition outage range from 8.75 days for 65°F service water to 38.04 days for 80°F service water. Following this outage the transition loads decay to less than the heat load from a 49-assembly EPU load resulting in a overall pool heat load less than the calculated normal maximum EPU heat load.

Loss of Cooling

The Spent Fuel Pool Cooling System was evaluated for a loss of cooling. With the Spent Fuel Pool at the maximum initial temperature of 145°F, the time to reach a pool temperature of 212°F for the maximum EPU pool heat load of 24.6×10^6 Btu/hr is calculated to be 7.5 hrs. A makeup water requirement of 46.8 gpm is needed to accommodate this boil-off-rate. Several makeup water sources are available to meet this requirement and can be established within this time frame.

The time for the pool temperature to rise from 145°F to 212°F for the maximum heat loads associated with the various service water temperatures is given in Table 2.5.4.1-3, Loss of Cooling – Time to 212°F & Make Up Rate. The time to reach a pool temperature of 212°F increases with increasing Service Water System temperature. This is because the delay time for offloading of spent fuel to the pool is determined by the temperature of the Service Water System at the time of offload. The increased heat removal capability of the Spent Fuel Pool Cooling System at colder Service Water temperatures allows for shorter offload delays. Therefore, if cooling is lost at the completion of offloading with the Service Water System at lower temperatures, the heat load in the pool is higher, which results in faster pool heat up rates.

In the event of a loss of the Spent Fuel Pool Cooling System the required water make up rate can be supplied from several available sources within the allotted time frame. These sources include either of two independent fire hoses each having a capacity of 100 gpm which is over 50 gpm greater than the maximum calculated makeup water requirement.

Concrete Temperature

The existing spent fuel pool design temperature requirements are being maintained for the uprate power level. Therefore, there is no impact to the pool liner or concrete temperature from water temperature changes due to EPU.

Purification Subsystem

EPU has no significant effect on the impurity levels in the Spent Fuel Pool or the design of the filtration and purification loop. The purification subsystem may experience a slight increase in the frequency of demineralizer resin replacement due to higher levels of fission products or crud in the pool. However, any significant increase in fission product inventory in the primary coolant system due to EPU will be mitigated by reactor coolant cleanup systems prior to transmission to the spent fuel pool. Refer to LR Section 2.5.6.3, Solid Waste Management System, for additional discussions regarding spent demineralizer resins and EPU affects on the Solid Waste Management System.

Shared Systems

The Spent Fuel Pool Cooling System is common to PBNP Unit 1 and Unit 2. A discussion of the sharing of the components of this system between the two systems is given in FSAR Appendix A-6. EPU does not affect this discussion or the ability of the system to perform its safety function. As a result of EPU there is an increase in the Spent Fuel Pool heat load. This increase has been evaluated and the system has sufficient capacity to handle this increase.

License Renewal

Portions of the Spent Fuel Pool Cooling System are within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1839 (Reference 2), Section 2.3.3.3, Spent Fuel Cooling System. Aging Management Programs used to manage the aging effects associated with the Spent Fuel Pool Cooling System are addressed in the NUREG-1839 (Reference 2), Section 3.3.2.3.4, Spent Fuel Cooling System – Aging Management Evaluation. EPU activities are not adding any new components within the existing license renewal system evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified as a result of EPU.

Results

EPU will result in an increase in the Spent Fuel Pool heat loads. The increase has been evaluated and is within the capability of the Spent Fuel Pool Cooling System. The system has sufficient capacity to maintain the pool temperature within design limits. In the event of loss of cooling several makeup sources are available to supply adequate makeup water to the pool. The evaluations performed in the above sections show that the Spent Fuel Pool Cooling System continues to comply with PBNP GDC 4 and 67.

2.5.4.1.3 Conclusions

PBNP has assessed the effects of EPU on the Spent Fuel Pool Cooling System and concludes that the system is adequate to operate at the proposed EPU. Based on this assessment, PBNP concludes that the Spent Fuel Pool Cooling 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 PBNP current licensing basis requirements and complies with PBNP GDC 4 and 67. Therefore, PBNP finds the proposed EPU acceptable with respect to the Spent Fuel Pool Cooling System.

2.5.4.1.4 References

1 ANSI/ANS 5.1, Decay Heat Power in Light Water Reactors," American National Standards Institute, 1979

2 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

Table 2.5.4.1-1 Normal Refueling w/ Spent Fuel Pool @ 120°F

Service Water Inlet Temperature (°F)	Spent Fuel Pool Heat Exchanger Capability – Single Train Operation (Btu/hr)	Calculated EPU Heat Load (Btu/hr)	Time to Start Offload After Shutdown (days) 1800MWt
65	16.158E+6	16.158E+6	5.73
80	11.800E+6	11.800E+6	33.36

Table 2.5.4.1-2 Full Core Offload w/ Spent Fuel Pool @ 145°F[1]

Service Water Inlet Temperature (°F)	Spent Fuel Pool Heat Exchanger Capability – Single Train Operation (Btu/hr)	Calculated EPU Heat Load (Btu/hr)	Time to Start Offload After Shutdown (days) 1800 MWt
60	25.146E+6	25.146E+6	11.82
65	23.698E+6	23.698E+6	15.12
70	22.244E+6	22.244E+6	18.89
75	20.786E+6	20.786E+6	23.92
80	19.323E+6	19.323E+6	32.00

(1) For comparison procedural evaluation preceding the most recent refueling outage (operation at 1540 MWt) found the allowable time to start offload after shutdown of 9 days at 80°F service water inlet temperature for a full core offload with the spent fuel pool at 145°F.

Table 2.5.4.1-3 Loss of Cooling – Time to 212°F & Make Up Rate

Service Water Temperature (°F)	EPU Spent Fuel Pool Decay Heat Load (Btu/hr)	Time From 145°F To 212°F (hrs)	Required Water Make Up Rate (gpm)
60	25.146E+6	7.3	47.8
65	23.698E+6	7.8	45.0
70	22.244E+6	8.3	42.3
75	20.786E+6	8.9	39.5
80	19.323E+6	9.6	36.7

2.5.4.2 Station Service Water System

2.5.4.2.1 Regulatory Evaluation

The station service water system (SW) provides essential cooling to safety-related equipment and also provides cooling to non-safety-related auxiliary components that are used for normal plant operation. The PBNP review covered the characteristics of the station SW components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with loss-of-offsite power). The PBNP review focused on the additional heat load that would result from the proposed EPU.

The NRC staff'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 to be compatible with the environmental conditions associated with normal operation, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents
- 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 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.

Specific review criteria are contained in SRP Section 9.2.1, as supplemented by Generic Letters (GL) 89-13 (Reference 1) and GL 96-06 (Reference 2).

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR) Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4, 5 and 44 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

Certain components of the SW System are shared by the two units. FSAR Appendix A.6, Shared Systems Analysis, presents a failure analysis of shared components.

CRITERION: Engineered Safety Features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (PBNP GDC 41)

CRITERION: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (PBNP GDC 52)

Each of the auxiliary cooling systems which serve an emergency function provides sufficient capability in the emergency mode to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the plant personnel and the public.

As stated in FSAR Section 9.6.1, Service Water System, Design Basis, the Service Water (SW) system shall provide sufficient flow to support the heat removal requirements of components required to mitigate the consequences of a Loss of Coolant Accident (LOCA) in one unit, while supporting the normal flow of the unaffected unit. Although SW is required to mitigate other plant accidents as well, a LOCA combined with normal operation of the unaffected unit is the most limiting event for the heat load imposed on the SW system.

The service water system is sized to ensure adequate heat removal based on the highest expected temperatures of cooling water, maximum loading and leakage allowances. The highest normally expected service water inlet temperature is 75°F. Calculations show that adequate service water flow is available at 80°F indicated temperature to transfer the design basis accident heat loads during the post-DBA injection and recirculation phases with three service water pumps in operation. All essential safety related heat exchangers have been demonstrated by analysis to be capable of transferring their design basis heat loads at 80°F.

The SW system is provided with a ring header and valves such that the component cooling water heat exchangers which are supplied with service water for cooling can have flow directed to them from either side of the ring header. Three of the six service water pumps are required to operate during the recirculation phase to cool the recirculation fluid and containment atmosphere in the unit suffering the accident and provide the necessary cooling for the other unit.

The SW system shall provide sufficient flow to the spent fuel pool heat exchangers to provide adequate heat removal of spent fuel decay heat.

The SW system shall provide a long-term makeup water source to the suction of the auxiliary feedwater (AF) pumps when the normal makeup source (the CSTs) is not available.

Additional information is provided in LR Section 2.5.4.4, Ultimate Heat Sink and Section 2.2.5, Seismic and Dynamic Qualification of Mechanical and Electrical Equipment.

Other FSAR sections that address the design features and functions of the SW system include:

- As discussed in FSAR Section 5.3.2.1, Containment Air Recirculation, each containment fan cooling coil in an air handling unit is designed to transfer up to 1.57×10^6 BTU/hr to the service water system during normal plant operation and 37.5×10^6 BTU/hr for limiting design basis accident conditions.
- FSAR Section 6.2, Safety Injection System and associated Table 6.2-7(a), Single Failure Analysis, Safety Injection System, analyzes the SW system for credible single active failures.

FSAR Table 6.3-1, Single Failure Analysis, Containment Air Recirculation Cooling System, also analyzes the SW system for credible single active failures.

- FSAR Appendix A.5, Seismic Design Analysis, states that the Service Water pumps and piping, including service water for fire protection of Class I components where required is classified as Seismic Class I. Service Water pipe and pipe supports are designed to accommodate design basis load combinations described in FSAR Appendix A.5, including pipe displacements and hydraulic loads that may result from water hammer in the containment fan cooler return lines. However, FSAR Section 9.6.3, System Evaluation further clarifies that:
  - SW piping beyond the Class I structures only supplies non-essential equipment. That piping can be isolated by the safeguards sequence automatically, by remote manual actuation of powered isolation valves, and by local manual valves. Both the powered and manual isolation valves are located within the Class I structure.
  - The service water piping in the Control Room Heating, Ventilation and Air Conditioning Room is Seismic Class I.

PBNP addressed overpressurization of isolated piping inside containment and boiling/flow blockage/water hammer effects in service water piping to the containment recirculation fans in PBNPs responses to GL 96-06 (Reference 2). In a letter from NRC to NMC, Completion of Licensing Action for Generic Letter 96-06 (Reference 2), Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions, dated October 5, 2004, the NRC closed NRC Generic Letter 96-06 (Reference 2) for PBNP.

The PBNP commitments related to GL 89-13 (Reference 1) are summarized in the PBNP Regulatory Information System. The purpose of the Generic Letter (GL) 89-13 Program (Reference 1) is to document ongoing actions taken by PBNP to meet commitments to the NRC in response to GL 89-13 (Reference 1).

FSAR Section 15.2.14, Open-Cycle Cooling (Service) Water System Surveillance Program, describes the aging management program in place to manage the aging effects caused by exposure of internal surfaces of metallic components in water systems (e.g., piping, valves, heat exchangers) to raw, untreated (e.g., service) water. The aging effects are managed through (a) surveillance and control of biofouling, (b) verification of heat transfer by testing, and (c) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function. Inspection methods include visual (VT) , ultrasonic (UT), eddy current (ECT), and Tangential Radiography (RT). This program complies with PBNP's response to NRC Generic Letter 89-13 (Reference 1).

In addition to the evaluations described in the FSAR, the service water system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 3)

With respect to the above SER, the service water system is described in Section 2.3.3, Auxiliary Systems. Aging effects, and the programs used to manage the aging effects associated with service water, are discussed in Section 3.3 of the SER.

2.5.4.2.2 Technical Evaluation

Introduction

The service water system is described in FSAR Section 9.6, Service Water System. The service water system takes suction from Lake Michigan via the pump bays in the Circulating Water pump house and supplies cooling water to reactor plant auxiliary loads as well as various turbine plant loads. In addition, service water is the long-term makeup source to the suction of the auxiliary feedwater pumps when the normal makeup source is not available. The system is designed to provide adequate cooling to critical and non-critical loads during normal operation and to critical loads during abnormal and accident conditions. A maximum SW intake temperature of 80°F is used for essential service water evaluations.

The service water system consists of six service water pumps and a large single ring supply header made up of piping, various strainers, instrumentation, and valves. The supply header exits the pumphouse through two pipelines called the North and South headers which run to the primary auxiliary building where they rejoin to form the West header. The supply of SW for essential services is redundant and can be maintained in case of failure of one section of the ring header. The system normally discharges back into Lake Michigan via the circulating water discharge flumes.

Supply of service water for essential services is redundant and can be maintained in case of failure of one section of the ring header. FSAR Table 9.6-1 is a list of the essential service loads supplied by the service water (SW) system. All of the essential services can be supplied service water from either the North or South headers. Return service water is directed to the return line of the circulating water (CW) system. The containment ventilation coolers (HX-15) are supplied in pairs from the service water loop.

The redundant motor operated valves in the containment cooler service water discharge lines (1/2SW-2907,2908) will automatically open on a safeguards actuation signal. Each cooler inlet and outlet are provided with a manual shutoff and drain capability. Manual valves allow each cooler to be isolated individually for leak testing. Service water to each cooler is isolated during the performance of the integrated leakage rate test. The containment ventilation cooler SW discharge lines are continuously monitored for radioactivity. A small bypass flow from the Service Water System (SW) return line of each cooler is diverted through a common header to radiation monitor 1/2RE-216. Upon indication of radioactivity in the common monitor, each cooler discharge line could be monitored individually to locate a defective cooler. The defective cooler might then be removed from service with its manual isolation valves.

The system is operated according to the Technical Specification (TS) 3.7.8 and Technical Requirements Manual (TRM) Section 3.7.7.

Description of Analyses and Evaluations

The service water systems and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations compared the existing design parameters of the systems/components with the EPU conditions for the following design aspects:

- Service water flow and heat removal requirements
- Design pressure/temperature of piping and components
- Overpressurization of isolated piping inside containment and boiling/ flow blockage/water hammer effects in service water piping to the containment recirculation fan coolers (NRC Generic Letter 96-06 Reference 2)
- Fouling in heat exchangers cooled by service water (NRC Generic Letter 89-13, Reference 1)

Other evaluations of service water system and components are addressed in the following Licensing Report sections:

- Piping/component supports – LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports
- Protection against dynamic effects of missiles, pipe whip, discharging fluids and flooding effects – LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects; LR Section 2.5.1.1, Flood Protection; and Section 2.5.1.3, Pipe Failures
- Service water instrumentation - LR Section 2.4, Instrumentation and Controls
- Environmental qualification – LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- Safety related valve and pump testing and valve closure, including containment isolation requirements – LR Section 2.2.4, Safety-Related Valves and Pumps
- Protection against internal missiles and turbine missiles - LR Section 2.5.1.2.1, Internally Generated Missiles
- Evaluation of systems containing heat exchangers cooled by service water is provided in the following:
  - LR Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System
  - LR Section 2.5.4.3, Reactor Auxiliary Cooling Water Systems (Component Cooling Water System)
  - LR Section 2.5.4.5, Auxiliary Feedwater
  - LR Section 2.6.5, Containment Heat Removal
  - LR Section 2.7, Habitability, Filtration, and Ventilation
  - LR Section 2.5.6, Waste Management Systems

- Service water to the auxiliary feedwater system for long term heat removal from the primary system - LR Section 2.5.4.5, Auxiliary Feedwater
- Post-accident heat removal requirements – LR Section 2.6.1, Primary Containment Functional Design
- Reactor cooldown requirements – LR Section 2.8.4.4, Residual Heat Removal System
- Control of radioactive material and the monitoring of releases - LR Section 2.10.1, Occupational and Public Radiation Doses

Results

The following subsections evaluate the specific service water system and component licensing, design and performance capabilities while at EPU conditions.

General Design Criteria

The evaluation of the service water system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 40. The system is protected from the dynamic effects of pipe break, including missiles, pipe whip, discharging fluids and flooding, as described in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures. Safety related equipment is environmentally qualified for the worst case environments as discussed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment.

The evaluation of the service water system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 4. The Service Water system can provide sufficient flow to support the heat removal requirements of components required to mitigate the consequences of a Loss of Coolant Accident (LOCA) in one unit, while supporting the flow of the unaffected unit. The SW system is provided with a ring header and valves such that the essential heat exchangers which are supplied with service water for cooling can have flow directed to them from either side of the ring header.

Modifications are being made to the AFW system to support EPU. To address plant transients that require heat removal from the SGs following Condensate Storage Tank (CST) depletion or failure, new SW lines will be added to the new MDAFW pumps located in the 8' elevation of the Primary Auxiliary Building (see LR Section 2.5.4.5, Auxiliary Feedwater) or alternatively, the SW lines to the present MDAFW pumps will be rerouted to the new pumps. The TDAFW pumps are already provided with backup SW lines. The Containment Fan Coolers and other components cooled by SW during DBAs with credit AFW flow are not adversely affected by the increased AFW flow requirement.

Modifications are being made to some of the non-safety related (i.e. turbine/generator) components cooled by the SW system. However, these modifications will have a negligible effect on the overall performance of the SW system. Minor flow balancing changes to non-safety related components will be performed as part of the modification process so cooling flow requirements to safety-related components will be maintained. No new operating modes or system lineups are required as a result of EPU. Therefore, the SW system continues to meet the design requirements with respect to sharing of system and components in accordance with PBNP licensing basis and PBNP GDC 4.

The evaluation of the service water system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDCs 41 and 52. The service water system provides heat removal from the reactor and transfers the heat ultimately to the environment. The service water system provides this capability under both normal operating and accident conditions and is capable of achieving this function considering a single failure. The implementation of EPU does not affect the capability of the system to perform this function as demonstrated by the system and component evaluation results described below and by the analysis results discussed in LR Section 2.6.1, Primary Containment Functional Design, and LR Section 2.8.4.4, Residual Heat Removal System, using the service water system during the postulated cooldown and accident scenarios.

Service Water Flow and Heat Removal from Cooled Components

The service water system supplies cooling water to both safety-related and non-safety related components. The existing service water flow rates are capable of removing the required EPU heat loads from each cooled safety-related component. Modifications are being made to some of the non-safety related components cooled by the SW system. Any minor flow balancing changes to non-safety related components will be performed as part of the modification process such that cooling flow requirements to safety-related components will be maintained. The EPU evaluation of systems containing these cooled components is performed in the system-related LR sections referenced above.

The evaluations also confirmed that following a postulated loss of coolant accident, the operation of three service water pumps supplies sufficient flow to the required heat loads via the containment fan coolers (CFCs), component cooling water heat exchangers, emergency diesel generator coolers, primary auxiliary building (PAB) battery room coolers, turbine driven auxiliary feedwater pump bearings, and CFC motor coolers.

The majority of the cooled components are unaffected by EPU conditions since their functions and heat removal requirements are unrelated to the reactor power level or turbine cycle performance. The components significantly affected by EPU include the following:

- Component cooling water heat exchangers – primarily affected by increased reactor decay heat at the EPU power level transferred by the residual heat removal heat exchangers to the component cooling water system during cooldown and accidents. The current service water flow rates are capable of removing the required heat loads from the component cooling water heat exchangers at the EPU power level.
- Spent fuel pool heat exchangers – removes the higher fuel decay heat at the EPU power level from the spent fuel stored continuously in the spent fuel pool. The current service water flow rates are capable of removing the required heat loads from the spent fuel pool heat exchangers at the EPU power level.
- Generator bus duct coolers – Generator operation at higher MWe causes added heat to be released to the bus duct coolers. The existing bus duct coolers are not capable of adequate heat removal at the EPU power level and are being replaced. The replacement bus duct

coolers will require more SW flow than the existing bus duct coolers. However, the condensate pumps and feedwater pumps are also being replaced to support EPU and will no longer require cooling water flow from the SW system. Since these components receive flow from the same header, adequate SW flow will be available to generator bus duct coolers. The resulting flow balancing changes will be implemented as part of the modification process and will ensure there is adequate flow to all safety-related components.

- Containment fan coolers – additional energy released to containment during accident events due to the higher EPU power level is removed through other means, such as the crediting of additional structural heat sinks inside the containment, which results in reduced required heat removal by the containment fan coolers. For additional discussion see LR Section 2.6.1, Primary Containment Functional Design.
- The SW provides a back-up source of water to the AFW system in case the CST is depleted or it fails due to a seismic event or a tornado generated missile. This will require the addition of new SW lines to the new MDAFW pumps located in the Primary Auxiliary Building or alternatively, rerouting the SW lines for the present MDAFW pumps to the new pumps. During plant transients that require heat removal from the SGs, either the TDAFW pump or the MDAFW pump can be supplied with 275 gpm SW flow if the CST is not available.
- Although EPU increases the AFW System flow requirements from 200 gpm to 275 gpm, this does not affect the limiting SW flow condition which is postulated for DBAs as explained on the GL 96-06 discussion that follows. Consequently, the Containment Fan Coolers and other components cooled by SW during a DBA are not adversely affected by the increased AFW flow requirements.

Increasing heat loads from cooled components with the existing service water flow rates causes their service water outlet temperatures to be higher. For conservatism, individual essential safety-related components have been evaluated using an inlet temperature of 80°F. However, the containment integrity analysis and cooldown analysis discussed in LR Section 2.6.1, Primary Containment Functional Design, and LR Section 2.8.4.4, Residual Heat Removal System, use a bounding value of 82°F. The service water piping and valves at the outlets of affected safety-related components experience higher operating temperatures at EPU while the common discharge headers to the circulating water outlet pipes experience small temperature changes due to the effects of these higher outlet temperatures. However, service water flow rates discharging to the circulating water discharge flumes are small in comparison with circulating water discharge flow rates. These higher temperatures have been compared to the design temperatures of these portions of the service water system and the EPU temperatures are bounded by system design temperatures. For additional discussion on discharge flow rates see LR Section 2.5.8.1, Circulating Water System and Section 2.5.4.4, Ultimate Heat Sink.

Since the existing service water flow rates are not affected by EPU conditions, the service water pumps capacities are acceptable for EPU operation. The existing service water operating pressures at EPU conditions are also not affected since minor modifications being made to the non-safety related portion of the service water system will have negligible effect on the overall performance of the system and the pumps will continue to operate at their current discharge pressure.

The service water system also provides a long term makeup water source to the suction of the auxiliary feedwater pumps when the normal source (i.e., the condensate storage tanks (CSTs)) is not available. Although the minimum required auxiliary feedwater system flow rate is increasing, adequate service water flow will be provided to the auxiliary feedwater system while maintaining adequate flow to other SW supplied/cooled components. Therefore, the existing service water capability remains acceptable for operation at EPU conditions. See LR Section 2.5.4.5, Auxiliary Feedwater, for additional details regarding the modification to the Auxiliary Feedwater System.

NRC Generic Letter 96-06

The implementation of EPU at the PBNP does not affect the previous corrective actions and responses to NRC Generic Letter 96-06 (Reference 2) and the subsequent closeout of GL 96-06 by the NRC via a letter dated October 5, 2004 (Reference 2).

In regard to the GL 96-06 (Reference 2) issue of overpressurizing, isolated portions of piping penetrating containment due to heatup from containment accident environments, a number of fixes were implemented. This included crediting existing valves for overpressure protection, adding relief valves maintaining the penetration drained of water during power operation, or demonstrating that the isolated line would not be overpressurized by the thermal transient assuming a containment design temperature of 286°F. The EPU does not change the current design pressures and temperatures of the containment penetration piping or isolation valves. The peak accident containment temperature at EPU conditions is expected to be 284.4°F which is the higher of the LOCA and MSLB cases. Since the EPU condition is below the containment design temperature/pressure, no additional or revised analysis is required to demonstrate their acceptability. EPU does not add any new containment penetrations.

The GL 96-06 (Reference 2) also questioned whether the higher heat loads at accident conditions could cause voiding and subsequent water hammer during the assumed coincidental loss of offsite power transient and, secondly, reduced flow due to two phase flow due to boiling in the service water cooling flow to heat exchangers exposed to the accident conditions, particularly the containment fan coolers. Detailed design analyses of these concerns were originally done by PBNP and accepted by NRC.

The EPU containment evaluations consider both the MSLB and LOCA DBAs. The DBA LOCA evaluation shows that no AFW flow is assumed to the SGs (the RCS is depressurized by the break and the SGs are not assumed to remove any heat). The DBA LOCA imposes the limiting accident condition on SW. The sensible and decay heat are removed from the containment through components (CFCs and RHR HX/CCW HX) ultimately cooled by SW. The SW demand is maximized in the recirculation phase.

For a DBA MSLB, the containment analysis does model AFW flow to the SGs, which would credit some containment heat removal through the non-faulted SG, but the MSLB analyses (both for the core response and the containment) do not model any heat removal through the RHR HX/CCW HX/SW system. Thus, the MSLB is far less limiting than the LOCA DBA on SW demand.

The original voiding and subsequent water hammer analysis considered a peak LOCA containment temperature of 278.7°F and determined that the water hammer transient loads did not challenge the structural integrity of the modified piping. This analysis was reviewed against the EPU conditions for service water flow rates and heat removal from the containment fan coolers. There are no changes in the cooler physical design service water restart sequencing, or the service water flow rates. The peak EPU LOCA post accident containment temperature of 279.9°F is slightly higher than the 278.7°F in the original PBNP analysis of this event. However, the conservatism of zero fouling used in the original analysis bounds this slight temperature increase. The MSLB is not limiting since the MSLB temperature peak (284.4°F) occurs well after SW flow is reestablished and voiding is reduced to zero. Prior to voiding being reduced to zero, the MSLB temperature remains below 250°F. Therefore, the acceptable conclusions of the original design analysis for water hammer remain valid for the EPU conditions.

The original two phase flow calculation assumed a containment temperature of 286°F. The current SW system design basis calculation also utilizes a containment temperature of 286°F when analyzing boiling in the containment fan coolers during post accident operation. Therefore, these calculations remain bounding for the EPU MSLB and LOCA events.

NRC Generic Letter 89-13

PBNP has a GL 89-13 Program (Reference 1), which complies with the NRC Generic Letter 89-13 (Reference 1). The EPU does not change the flow rate through the safety-related heat exchangers in the service water system. Accordingly, the surveillance and control techniques used to ensure the continued operability of GL 89-13 (Reference 1) components will not require change as a result of uprate.

Inspection and maintenance program for service water system piping and components will continue after the uprate. The uprate does not change the maintenance practices and training procedures.

The Extended Power Uprate does not affect the programs, procedures, and activities in place at PBNP Station in support of implementation of the requirements of GL 89-13 Reference 1). The program will continue to ensure that the service water system remain reliable and operable after the uprate.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the service water system are within the scope of License Renewal. EPU activities do not add any new types of components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the service water system at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.2.3 Conclusions

PBNP has assessed the effects that the proposed EPU would have on the station service water system and concludes that the system will adequately operate with the increased heat loads that would result from the proposed EPU. PBNP also concludes that the station service water system will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, PBNP has determined that the station SW system will continue to meet the requirements of PBNP GDCs-4, 40, 41, and 52 and Generic Letters 89-13 (Reference 1) and 96-06 (Reference 2). Based on the above, PBNP finds the proposed EPU acceptable with respect to the station service water system.

2.5.4.2.4 References

1 NRC Generic Letter (GL) 89-13, Service Water System Problems Affecting Safety-Related Equipment, July 18, 1989

2 NRC Generic Letter (GL) 96-06, Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions, September 30, 1996

3 NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.4.3 Reactor Auxiliary Cooling Water Systems (Component Cooling Water System)

2.5.4.3.1 Regulatory Evaluation

The PBNP review covered reactor auxiliary cooling water systems (i.e. Component Cooling (CC) Water System) that are required for (1) safe shutdown during normal operations, anticipated operational occurrences, and mitigating the consequences of accident conditions, or (2) preventing the occurrence of an accident. The system includes a closed loop component cooling water system for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling system (ECCS). The PBNP review covered the capability of the CC water system to provide adequate cooling water to safety related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water for safety related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The PBNP review focused on the additional heat load that would result from the proposed EPU.

The NRC's acceptance criteria for the component cooling water system are based on:

- GDC 4, insofar as it requires that structures, systems, and components (SSCs) important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents;
- 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 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.

Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 (Reference 2) and GL 96-06 (Reference 1).

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The equivalent PBNP GDC for 10 CFR 50 Appendix A GDC-4 and 5 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

As stated in FSAR Section 9.1.2, System Design and Operation, all component cooling lines inside containment have been analyzed for protection from missiles, pipe whip and jet impingement. Using Leak-Before-Break methodology, no credible missiles exist and therefore the component cooling piping is considered missile protected.

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

Certain components of the component cooling water system are shared by the two units. FSAR Section 6.2, Safety Injection System, Table 6.2-8, Shared Functions Analysis, describes how each component functions during normal operation and during the accident, and FSAR Appendix A.6, Shared Systems Analysis, presents a failure analysis of shared components.

There is no PBNP GDC equivalent for 10 CFR 50 Appendix A GDC 44 as it relates to the Component Cooling Water System.

The PBNP specific GDC for the component cooling water system are as follows:

CRITERION: Engineered Safety Features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (PBNP GDC 41)

Each of the auxiliary cooling systems which serves an emergency function provides sufficient capability in the emergency mode to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the plant personnel and the public.

As stated in FSAR Section 9.1, Component Cooling Water, Design Basis, the component cooling water (CC) system consists of four pumps, four heat exchangers, two surge tanks and the piping, valves, instrumentation, and controls necessary to provide the heat removal capability to support the operation of the units and equipment. The component cooling water loop in each unit consists of two pumps (11A&B), two heat exchangers (HX-12A&B in Unit 1 and HX-12C&D in Unit 2), a surge tank, a supply header, and a return header. Heat exchangers HX-12B&C may be used in either loop as cooling conditions require. The capability to use the pumps assigned to one loop to supply both loops is also provided. The CC system performs the following safety-related functions:

- Remove residual and sensible heat from the reactor coolant system, via the residual heat removal (RHR) heat exchangers during the recirculation phase of Safety Injection to support long-term core cooling. This function is described in FSAR Section 6.2, Safety Injection System.
- Remove heat from the RHR heat exchangers to terminate the steam releases associated with the license basis dose analyses for the postulated rupture of a steam pipe (MSLB), steam generator tube rupture (SGTR), and reactor coolant pump locked rotor accidents.
- Remove heat from the RHR, SI, and containment spray pump seal coolers to maintain the integrity of the pump seals.

Other FSAR sections that address the design features and functions of the component cooling water system include:

- FSAR Section 6.2, Safety Injection System and associated FSAR Table 6.2-7(a), Single Failure Analysis – Safety Injection System analyzes the component cooling system for credible single active failures.
- FSAR Section 6.5, Leakage Detection Systems, describes the design features for the detection of leakage of reactor coolant from either the reactor coolant system or the recirculation or residual heat removal system into the component cooling water system.
- FSAR Appendix A.5, Seismic Design Analysis, describes the component cooling loop as Seismic Class I.

PBNP addressed overpressurization of isolated piping inside containment and boiling/flow blockage/water hammer effects in service water piping to the containment recirculation fans in PBNPs responses to GL 96-06 (Reference 1). In a letter from NRC to NMC, Completion of Licensing Action for Generic Letter 96-06 (Reference 1), Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions, dated October 5, 2004, the NRC closed NRC Generic Letter 96-06 (Reference 1) for PBNP.

The PBNP commitments related to GL 89-13 (Reference 2) are summarized in the PBNP program document entitled, GL 89-13 Program (Reference 2), and are tracked in the PBNP commitment tracking system. The purpose of the Generic Letter (GL) 89-13 Program (Reference 2) is to document ongoing actions taken by PBNP in response to GL 89-13 (Reference 2).

In addition to the evaluations described in the FSAR, the component cooling water system was evaluated for PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 3)

Portions of the component cooling water system are within the scope of License Renewal as described in License Renewal SER, Section 2.3.3.2.

2.5.4.3.2 Technical Evaluation

Introduction

The Component Cooling Water System is described in FSAR Section 9.1, Component Cooling Water. The Component Cooling Water System is designed to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. Component cooling water circulates through parallel flow paths through various components, where it picks up heat from other systems and transfers the heat to the service water system via the component cooling water heat exchangers. The maximum assumed service water inlet temperature is 80°F, which is the value used for the evaluation of essential safety-related design features.

During normal full power operation, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads and the standby pump and the shared heat exchangers provide backup. Two pumps and two heat exchangers are used to remove the residual and sensible heat during plant shutdown. If one of the pumps or two of the heat exchangers are not available, safe shutdown of the plant is not affected; however, the time for cooldown is extended.

The component cooling loop serves as an intermediate boundary between the reactor coolant system and the service water system, transferring heat from the reactor coolant system to the service water system. This double barrier arrangement reduces the potential for leakage of radioactive reactor coolant to the environment via the service water system. Active components which are relied upon to perform the emergency core cooling function are redundant. The design provides for detection of radioactivity and also provides for isolation means.

Description of Analyses and Evaluation

The Component Cooling Water System and its components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations compared the existing design parameters of the system/components with the EPU conditions for the following design aspects:

- Component cooling water heat exchanger performance (flow rates, duty and temperatures) at the increased EPU heat loads during normal power operation, normal cooldown, and abnormal transient and accident conditions (including Generic Letter 89-13 (Reference 2)
- Component cooling water system temperature limits
- Design pressure/temperature of piping and components versus the EPU operating pressures and temperatures
- Component cooling water relief valve capacities
- Protection of isolated piping sections from heatup effects (NRC Generic Letter 96-06 (Reference 1))

Other related evaluations of component cooling water system and components are addressed in the following Licensing Report sections:

- Piping/component supports – LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports
- Protection against dynamic effects of missiles, pipe whip, discharging fluids and flooding - LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects; LR Section 2.5.1.1, Flood Protection; and LR Section 2.5.1.3, Pipe Failures
- Component cooling water instrumentation – LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems
- Environmental qualification – LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- Safety related valve and pump testing and valve closure, including containment isolation requirements – LR Section 2.2.4, Safety-Related Valves and Pumps

- Protection against internal missiles and turbine missiles – LR Section 2.5.1.2.1, Internally Generated Missiles and Section 2.5.1.2.2, Turbine Generator
- Evaluation of heat exchangers cooled by component cooling water – LR Section 2.1.11, Chemical and Volume Control System; LR Section 2.2.2.6, Reactor Coolant Pumps and Supports; LR Section 2.5.6, Waste Management Systems; LR Section 2.8.4.4, Residual Heat Removal System; LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents
- Post-accident heat removal requirements – LR Section 2.6.1, Primary Containment Functional Design
- Appendix R Cooldown – LR Section 2.8.4.4, Residual Heat Removal System

Results

The subsections below evaluate the specific component cooling water system and component licensing, design and performance capabilities while at EPU conditions.

General Design Criteria

The evaluation of the CC system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 4. Although the systems for each unit may be connected under abnormal conditions, the CC water system for each unit is normally aligned such that Unit 1 and Unit 2 have hydraulically independent systems. Each system includes two redundant pumps, one dedicated heat exchanger per unit, and the ability to align the two shared standby CC heat exchangers to either unit if necessary. No physical changes are being made to the CC system and no new operating modes or system lineups are required as a result of the EPU. Therefore, the CC water system continues to meet design requirements with respect to sharing of system and components in accordance with PBNP licensing basis and PBNP GDC 4.

The evaluation of the component cooling water system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 40. The system is protected from the dynamic effects of pipe break as described in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures. Safety-related equipment is environmentally qualified for the worst case environments as discussed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment.

The evaluation of the component cooling water system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 41. The component cooling water system provides heat removal from the reactor and transfers the heat ultimately to the environment. The component cooling water system provides this capability under both normal operating and accident conditions and is capable of achieving this function considering a single failure. The implementation of EPU does not affect the capability of the system to perform this function as demonstrated by the system and component evaluation results described below and by the analysis results discussed in LR Section 2.6.1, Primary Containment Functional Design and Section 2.8.4.4, Residual Heat

Removal System, using the service water system during the postulated cooldown and accident scenarios.

Component Cooling Water Heat Removal Capability

Component cooling water is provided to safety-related and non-safety related plant components including:

- Residual heat exchangers
- Reactor coolant pumps
- Nonregenerative heat exchanger
- Excess letdown heat exchanger
- Seal water heat exchanger
- Boric acid recycle evaporator and distillate coolers
- Sample heat exchangers
- Waste gas seal water heat exchangers
- Residual heat removal pumps
- Safety injection pumps
- Containment spray pumps
- Cryogenic gas compressors
- Letdown gas stripper condensers

These cooled components are capable of removing the required EPU heat loads with the existing component cooling water supply flow rates.

Since none of the cooled components require more cooling flow, the existing component cooling water and service water flow rates through the component cooling water heat exchangers are not changed by the EPU.

During normal plant full power operation and normal cooldown, the component cooling water heat exchangers are capable of maintaining the cooling water supply temperature to individual cooled components below the following limits:

- 105°F - Normal Operation
- 125°F - Normal Cooldown (for up to 2 hours during initiation of cooldown)
- 40°F - Minimum to RCP Inlet

At normal plant EPU full power operation, the heat loads from the cooled components are not significantly different and; therefore, the above temperature limits are not affected while maintaining the current component cooling water flow rates.

During normal plant cooldown, the maximum component cooling water heat load occurs when the residual heat removal system is first placed in service as early as four hours after reactor shutdown. While there is higher reactor decay heat at the EPU power level, the maximum heat loads imparted on the CC system by the residual heat removal system will not increase as a result of EPU. The reactor coolant flow through the residual heat removal heat exchangers is throttled to limit cooldown of the reactor coolant system to 50°F/hr and to limit the component cooling water heat exchanger outlet temperature to 125°F. As a result of maintaining these limits with the higher reactor decay heat while maintaining the current component cooling water flow rates, the normal cooldown is lengthened as described in LR Section 2.8.4.4, Residual Heat Removal System.

During LOCA conditions, the component cooling water heat exchangers remove heat from the containment sump and reactor coolant system via the residual heat removal heat exchangers. The accident heat loads at EPU conditions are higher due to the higher reactor decay heat at the EPU power level. The EPU analyses described in LR Section 2.6.1, Primary Containment Functional Design confirm that the component cooling water heat exchangers provide sufficient heat removal for mitigation of postulated accidents while maintaining the current component cooling water flow rates.

During Appendix R cooldown following a plant fire, the component cooling water heat exchangers remove heat from the RHR system and are able to bring the plant to cold shutdown within 72 hours as described in LR Section 2.8.4.4, Residual Heat Removal System.

EPU Operating Conditions versus Design Conditions of Piping and Components

The component cooling water system flow rate does not change at the EPU conditions and no physical changes are being made to the system. Therefore, the component cooling water system operating pressures are not affected by EPU conditions and the existing component design pressures are acceptable.

The existing component cooling water piping to/from the reactor coolant pump (RCP) thermal barrier is designed for the reactor coolant system pressure and temperature in event of a failure of the thermal barrier. The reactor coolant system design conditions do not change due to EPU; therefore, the design pressure and temperature of this portion of the component cooling water system is acceptable for EPU operation.

The maximum temperatures observed in the CC system occur during normal cooldown when the RHR system is placed into service. After implementation of EPU, the maximum CC temperatures will not change, but the time to cooldown the plant will be extended. Therefore, EPU has no effect on the maximum CC temperatures. The effect on the surge tank volume due to thermal expansion in the system is insignificant in comparison to the capacity of the surge tank.

The design temperatures of the component cooling water heat exchangers, pumps, surge tank, piping and valves bound the maximum component cooling water system temperatures at EPU operation.

Therefore, the CC system design parameters bound all EPU operating conditions, thus the CC system piping, valves, and components are acceptable for EPU operation.

Component Cooling Water Relief Valve Capacities

The component cooling water system relief valves either have no change or small changes in temperatures that are bounded by the relief valve design. Since the EPU condition is below the system design temperature/pressure, no additional analysis is required to demonstrate their acceptability.

The postulated flow, pressure and temperature from a failure of the RCP thermal barrier does not change for EPU operation since there are no changes to the existing reactor coolant system design conditions and no changes are being made to the reactor coolant pump thermal barrier. Therefore, the relief valves on the component cooling water piping at the reactor coolant pump thermal barrier and on the component cooling water surge tank are unaffected by EPU conditions.

NRC Generic Letters 89-13 and 96-06

The issues in these Generic Letters are related to service water fouling in heat exchangers, heatup and overpressurization of isolated portions of piping inside containment, and boiling/water hammer in service water cooling lines to the containment atmosphere recirculation coolers.

The issue in NRC Generic Letter 96-06 (Reference 1) related to the heatup/overpressurization of isolated component cooling water piping inside containment was evaluated by PBNP in their previous responses and, there were no concerns identified in the component cooling water piping inside containment. This issue was closed out by the NRC in a letter dated October 5, 2004. This conclusion is not affected by EPU conditions since there are no physical changes or operational changes required by EPU that would affect the containment penetration piping or isolation valves. Therefore, no additional lines from the CC system that penetrate the containment are considered a potential concern; no new relief valves are required and the existing relief valves remain acceptable.

The small increase in the peak containment post-accident temperature (refer to LR Section 2.6.1, Primary Containment Functional Design) at EPU conditions has no impact on the CC water system inside containment. Relief valves are installed on all CC lines downstream of components located inside containment. Since the EPU condition is below the system design temperature and pressure, no additional analysis is required to demonstrate its acceptability. Therefore, no additional lines from the CC water system that penetrate the containment are considered a potential concern; no new relief valves are required, and the existing relief valves remain acceptable at EPU conditions.

The issue in NRC GL 89-13 (Reference 2) is related to evaluation of safety-related heat exchangers using service water and whether they have the potential for fouling, thereby causing degradation in performance, and the mandate that there exist a permanent plant test and inspection program to accomplish and maintain this evaluation. PBNP is committed to a program to perform periodic inspection and preventative maintenance of CC heat exchangers. The conclusions relative to these original responses are not affected by the EPU since the existing procedures and activities in place at PBNP in support of GL 89-13 (Reference 2) are unaffected and require no changes. Subsequent to the implementation of EPU, CC heat exchangers will continue to be periodically inspected and maintained.

With respect to performance, the PBNP program for monitoring of heat exchangers in the SW system implements periodic performance testing of the CC heat exchangers. The performance test results are used to determine the existing heat transfer margin. Current heat removal capability, based on analysis of the test results, is compared with the CC heat exchanger data sheet to assure the heat exchangers meet or exceed their design heat removal capability. Subsequent to the implementation of EPU, CC heat exchangers will continue to be periodically tested to ensure their ability to remove the design heat loads.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the component cooling water system are within the scope of License Renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal evaluation boundaries. Because no modifications are necessary for the component cooling water system, the EPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.3.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the reactor auxiliary cooling water systems (i.e. component cooling water system) and concludes that PBNP has adequately accounted for the increased heat loads from the proposed EPU on system performance. PBNP concludes that the component cooling water system will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, PBNP has determined that the component cooling water system will continue to meet the requirements of PBNP GDCs 4, 40 and 41and Generic Letters 89-13 (Reference 2) and 96-06. (Reference 1). Based on the above, PBNP finds the proposed EPU acceptable with respect to the component cooling water system.

2.5.4.3.4 References

1. NRC Generic Letter 96-06, Completion of Licensing Action for Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions, dated October 5, 2004

2. NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment, July 18, 1989

3. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.4.4 Ultimate Heat Sink

2.5.4.4.1 Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The PBNP review focused on the impact that the proposed EPU has on the decay heat removal capability of the ultimate heat sink. Additionally, the PBNP review included evaluation of the design-basis ultimate heat sink temperature limit 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 NRC's acceptance criteria for the UHS are based on:

- 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 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.

Specific review criteria are contained in SRP Section 9.2.5.

PBNP Current Licensing Basis

The systems provided to transfer heat from the safety-related components to the ultimate heat sink (Lake Michigan) are the service water and the component cooling water systems.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-5 and 44 is as follows:

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

A functional evaluation of the components of the systems which are shared by the two units is provided in FSAR Appendix A.6, Shared Systems Analysis, together with a short discussion on the operation of those items of shared equipment which are components of the engineered safety features system.

FSAR sections that address the design features and functions of the ultimate heat sink include:

- FSAR Section 1.3, General Design Criteria, which states that the Circulating Water Pumphouse structure is designed to withstand the effects of a tornado.

- FSAR Section 2.5, Site and Environment - Hydrology, which describes the hydrology of the site, including the size and water level of Lake Michigan and the general arrangement of the intake structure.
- FSAR Section 9.1, Component Cooling Water, which describes the component cooling water system design and its rejection of heat to the service water system.
- FSAR Section 9.6, Service Water, which describes the service water system and its use of Lake Michigan as a water source.
- FSAR Section 9.10, Fire Protection System, that incorporates by reference the PBNP Fire Protection Evaluation Report (FPER) that in turn describes the use of Lake Michigan as a water source.
- FSAR Section 10.1, Steam and Power Conversion System, that describes the Circulating Water System and the Circulating Water Pumphouse structure.

In addition to the evaluations described in the FSAR, PBNP's ultimate heat sink was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005 (Reference 1)

With respect to the above SER, the ultimate heat sink is described in SER sections 2.3.3.5, Service Water and 2.4.3, Circulating Water Pumphouse Structure.

2.5.4.4.2 Technical Evaluation

Introduction

The ultimate heat sink is described in the FSAR sections listed above. The ultimate heat sink is Lake Michigan, which provides water to the service water (SW) system via the circulating water pumphouse forebay. The pumphouse is Seismic Class I to the extent that water is always available to the service water system. The service water system provides cooling water for heat removal from safety-related heat exchangers, including the CCW heat exchangers which cool the RHR system, and provides a backup supply of water from the ultimate heat sink to the auxiliary feedwater system for emergency heat removal from the reactor coolant system. Refer to LR Section 2.5.4.2, Station Service Water System, for a description of the cooled components and the water users supplied by the service water system.

A conservative lake water temperature of 80°F or higher is used for evaluating safety related components which rely on the ultimate heat sink for heat removal. Refer to LR Section 2.8.4.4, Residual Heat Removal System and LR Section 2.6.1, Primary Containment Functional Design which describe the cooldown and postulated accident scenarios using the ultimate heat sink for heat rejection.

Lake Michigan is also used by the non-safety related circulating water system to provide cooling water for heat removal from the turbine cycle during normal plant power operations. Refer to LR Section 2.5.8.1, Circulating Water System.

Description of Analyses and Evaluations

The ultimate heat sink was evaluated to ensure it is capable of performing its intended function of a reliable water supply and heat removal capacity for normal and accident conditions following EPU.

The ultimate heat sink was evaluated for the circulating water discharge temperature during EPU normal power operation and initial normal cooldown, including the effect of the service water discharge temperatures during normal power operation and cooldown. These effects were evaluated against the Wisconsin Pollution Discharge Elimination System (WPDES) permit limits for the PBNP in LR Section 2.5.8.1, Circulating Water System.

Other evaluations related to the ultimate heat sink are addressed in the following Licensing Report sections:

- Circulating water discharge temperatures and flow rates to Lake Michigan and the WPDES permit limits - LR Section 2.5.8.1, Circulating Water System.
- Service water discharge temperatures, heat loads and flow rates to the circulating water discharge to Lake Michigan - LR Section 2.5.4.2, Station Service Water System.
- Component cooling water temperatures, heat loads and flow rates to the service water system and to the ultimate heat sink - LR Section 2.5.4.3, Reactor Auxiliary Cooling Water Systems (Component Cooling Water System).
- Post-accident heat removal requirements - LR Section 2.6.1, Primary Containment Functional Design.
- Reactor cooldown requirements - LR Section 2.8.4.4, Residual Heat Removal System.

Results

The ultimate heat sink continues to meet its licensing, design and performance capabilities at EPU conditions as evidenced by the evaluation results described below.

General Design Criteria

The evaluation of the ultimate heat sink capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 4. The UHS is essentially an infinite heat sink which contains sufficient volume to provide cooling water to both units under all normal, abnormal, and accident conditions. Therefore, the UHS continues to meet the design requirements with respect to sharing of system and components in accordance with PBNP licensing basis and PBNP GDC 4.

Water Supply and Heat Removal Requirements

The ultimate heat sink will continue to provide the required water supply and heat sink capacity at EPU conditions. The service water flow requirements for cooling of safety related heat exchangers are not changed by EPU. The analysis results discussed in LR Section 2.8.4.4, Residual Heat Removal System and LR Section 2.6.1, Primary Containment Functional Design confirm that the ultimate heat sink will continue to provide sufficient water supply and heat removal for cooldown and to mitigate the postulated accident scenarios.

The service water system provides a long-term makeup water source from the ultimate heat sink to the suction of the auxiliary feedwater pumps when the normal source (i.e., the condensate storage tanks (CSTs)) is not available. The service water flow requirement to the auxiliary feedwater system has increased at EPU, but is small in regard to the design of the ultimate heat sink and the pumphouse structure used by the service water pumps. See LR Section 2.5.4.2, Station Service Water System, and LR Section 2.5.4.5, Auxiliary Feedwater, for additional details.

The service water returned to the ultimate heat sink from cooled components experiences a small temperature change due to the higher heat loads from the EPU NSSS thermal power level at normal operating conditions and from the higher reactor decay heat during cooldown and accident conditions. During normal operation and normal cooldown, the SW discharge temperatures increase slightly and the time to cool down the plant is extended. During accident conditions, the SW discharge temperatures continue to be bounded by existing analyses and the system design parameters. The circulating water discharge flow rate to Lake Michigan does not change at EPU which results in higher discharge flow temperatures as discussed in LR Section 2.5.8.1, Circulating Water System. Service water discharges into the circulating water outlet piping prior to its discharge to Lake Michigan. However, the effect of the EPU service water temperatures during normal operation, normal cooldown, and accident conditions is minimal because the total service water flow of 12,000 to 15,000 gpm is mixed with a circulating water flow of approximately 680,000 gpm prior to discharge to Lake Michigan.

The heat sink capacity of Lake Michigan is easily able to absorb the added heat from circulating water and service water with negligible effect on the lake temperature. Refer to LR Section 2.5.4.2, Station Service Water System Water and LR Section 2.5.8.1, Circulating Water System for discharge flows, heat loads and temperatures.

The discharge of circulating water is governed by the Wisconsin WPDES permit. As discussed in LR Section 2.5.8.1, Circulating Water System, the higher circulating water temperature during normal plant power generation has no impact on the current WPDES permit which does not limit the maximum discharge temperature, differential temperature across the condenser, or total discharge heat. See LR Appendix D, Supplemental Environmental Report, Section 7.2, Aquatic Impacts.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the ultimate heat sink are within the scope of License Renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with the operation of the ultimate heat sink at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.4.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the UHS safety function, including the validation of the design-basis UHS temperature limit based on post-licensing data. Based on this information, PBNP concludes that the proposed EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of PBNP GDC 4 following implementation of the proposed EPU. Therefore, PBNP finds the proposed EPU acceptable with respect to the Ultimate Heat Sink.

2.5.4.4.4 References

1. NUREG-1839, Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, dated December 2005

2.5.4.5 Auxiliary Feedwater

2.5.4.5.1 Regulatory Evaluation

In conjunction with a Seismic Category I water source, the auxiliary feedwater system functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available. The auxiliary feedwater system is also used to provide decay heat removal capability necessary for withstanding or coping with a station blackout. The PBNP review of the proposed EPU focused on the system's continued ability to provide sufficient emergency feedwater flow at the expected conditions (e.g., steam generator pressure) to ensure adequate cooling with the increased decay heat. The PBNP review also considered 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 NRC acceptance criteria for the auxiliary feedwater system are based on:

- GDC 4, insofar as it requires that safety-related structures, systems, and components important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures
- GDC 5, insofar as it requires that safety-related structures, systems, and components 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 19, insofar as it requires that equipment at appropriate locations outside the control room be provided with (a) the capability for prompt hot shutdown of the reactor, and (b) a potential capability for subsequent cold shutdown of the reactor
- 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 structures, systems, and components to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure

Specific review criteria are contained in SRP Section 10.4.9.

PBNP Current Licensing Basis

The PBNP Auxiliary Feedwater (AFW) System uses four pumps for the two nuclear units. Each unit has its own turbine-driven (TD) AFW pump and there are two motor-driven (MD) AFW pumps that are shared between the two nuclear units. This arrangement provides for a reliable and adequate water supply. The primary AFW system piping (pumps suction and discharge) is Seismic Class I. The safety related source of water supply to the AFW System pumps is from the Seismic Class I portion of the Service Water System.

The water supply source for the AFW System is redundant. The normal source is by gravity feed from two nominal capacity 45,000 gallon condensate storage tanks (CST) while the safety-related Seismic Class I supply is taken from the plant service water system, whose pumps are powered from the emergency diesel generators if station power is lost. Switchover from the normal source to plant service water source is accomplished through manual operator action from the control room. Since the steam generators (SG) at PBNP are of the recirculating type, substantial time is available (approximately 30 minutes) before AFW is required due to the large water inventory in the SGs. This is adequate time for manual switchover actions necessary to assure adequate AFW supply.

As stated in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion. (PBNP GDC).

Although AFW is not classified as an Engineered Safety Feature (ESF) in FSAR Chapter 6, Engineered Safety Features Criteria, the following ESF-related PBNP GDCs were evaluated during the EPU review:

CRITERION: Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required. (PBNP GDC 1)

The AFW System is designated a Seismic Class I System, note that the Condensate Storage Tanks (CST) (normal suction source to AFW pumps) are not Seismic Class I. The quality requirements of each AFW component is controlled by the Quality Assurance Program.

CRITERION: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (PBNP GDC 2)

The AFW System is designated a Seismic Class I system. As a Class I system, AFW System components are designed so there is no loss of function in the event of the maximum hypothetical earthquake. Measures are also taken in the design to protect against high winds, flooding and other phenomena, such as the effects of a tornado.

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4).

This criterion is applicable to portions of the AFW System which are shared between Unit 1 and Unit 2. Sharing of the motor-driven AFW pumps will not prevent the AFW System from performing the required safety functions under emergency conditions.

CRITERION: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel. (PBNP GDC 11)

AFW System instruments and controls are located in the control room.

CRITERION: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (PBNP GDC 12)

This criterion is applicable to the instrumentation and control systems provided to monitor and maintain within prescribed operating ranges the temperatures, pressures, flows, and levels in the reactor coolant systems, steam systems, containments, and other auxiliary systems.

CRITERION: Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends. (PBNP GDC 37)

Although the AFW System is not classified as an engineered safety feature, it is required to provide high pressure feedwater to the steam generators in the event of an accident.

CRITERION: All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public. (PBNP GDC 38)

As an ESF-equivalent system, the AFW system components are tested and inspected in accordance with Technical Specification surveillance criteria and frequencies. Testing verifies MDAFW pump operability, TDAFW pump operability including a cold start, and operability of all required MOVs. Control circuits, starting logic, and indicators are verified operable by their respective functional test.

Criterion: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the Reactor Coolant System piping. An original design basis for protection of equipment against the dynamic effects of a rupture of the Reactor Coolant System piping is no longer applicable. (PBNP GDC 40)

This criterion is applicable to the AFW System Class I components both inside and outside containment. The AFW System safety-related functions will not be impaired as a result of a missile.

CRITERION: Engineered safety features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (PBNP GDC 41)

As an ESF-equivalent system, the AFW System is designed with sufficient mechanical and electrical redundancy such that a single failure of an active component, either in the system or in a supporting system, can be accommodated without loss of the overall AFW System safety-related functions.

CRITERION: Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a loss of coolant accident to the extent of causing undue risk to the health and safety of the public. (PBNP GDC 42)

As an ESF-equivalent system, the AFW System is designed to function following a loss-of-coolant accident. AFW System safety-related functions can be accomplished in the harsh environments resulting from the loss-of-coolant accident.

The AFW system also performs the following augmented quality functions.

As discussed in FSAR, Appendix A.1, Station Blackout (SBO), in the event of a station blackout, the AFW system is capable of automatically supplying sufficient feedwater to remove decay heat from both units without reliance on AC power for one hour. To support this capability, the minimum required volume in the condesate storage tank was determined to be adequate, the temperature in the AFW Pump Room would not increase above the maximum temperature for equipment reliability, and there is sufficient capacity in the safety related batteries to support operation of the safety related loads.

In the event of plant fires, including those requiring evacuation of the control room, the AFW system shall be capable of manual initiation to provide feedwater to a minimum of one steam generator per unit at sufficient flow and pressure to remove decay and sensible heat from the reactor coolant system over the range from hot shutdown to cold shutdown conditions. The AFW system shall support achieving cold shutdown within 72 hours.

In the event of an Anticipated Transient Without Scram (ATWS), the AFW system shall be capable of automatic actuation by use of equipment that is diverse from the reactor trip system. This is accomplished by the ATWS Mitigation System Actuation Circuitry (AMSAC) system described in FSAR Section 7.4, Other Actuation Systems and required by 10 CFR 50.62. AMSAC trips the main turbine and starts both the shared motor driven AFW pumps and the unit specific turbine driven AFW pump on loss of main feedwater when main turbine is above 40% nominal power.

An automatic safety-grade low suction pressure trip of each AFW pump is provided. This protects any operating AFW pumps following a sudden failure of the Condensate Storage Tank

(CST) due to a seismic event or tornado missile. Following the auto-trip, the pumps can be restarted after the operators transfer the suction source to the safety-grade SW system.

The auxiliary feedwater system has no functional requirements during normal, at power, plant operation. It is used during plant startup and shutdown and during hot shutdown or hot standby conditions when chemical additions or small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems.

The seismic qualification of the AFW system was evaluated in the NRC Safety Evaluation based upon the PBNP response to Generic Letter 81-14 (Reference 3). The conclusion of that safety evaluation was that the PBNP AFW system provides a reasonable assurance that it will perform its required safety function following a safe shutdown earthquake. (Reference 1)

The AFW system is described in the FSAR Section 5.2, Containment Isolation System, Section 7.4, Other Actuation Systems, Section 10.1, Steam and Power Conversion System, Section 10.2, Auxiliary Feedwater System, Section 14.1.10, Loss of Normal Feedwater, Section 14.1.11, Loss of All AC Power to Station Auxiliaries, Section 14.2.4, Steam Generator Tube Rupture, Section 14.2.5, Rupture of a Steam Pipe, Appendix A.1, Station Blackout, Appendix A.2, High Energy Pipe Failure, and Appendix A.6, Shared Systems Analysis.

In addition to the evaluations described in the FSAR, the AFW system was evaluated for the PBNP License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER discusses the AFW system in Section 2.3.4.3, Auxiliary Feedwater and Section 3.4, Aging Management of Steam and Power Conversion Systems.

2.5.4.5.2 Technical Evaluation

Introduction

The pre-EPU AFW system is described in FSAR Section 10.2, Auxiliary Feedwater System. The following describes the AFW system modifications which will be completed prior to EPU implementation and the system performance following these modifications.

PBNP will install two new higher capacity MDAFW pumps in a new location in the PAB to meet the higher, EPU flow requirement of 275 gpm total at the lowest SG safety valve pressure setpoint to both steam generators in each unit. In addition, the new MDAFW pumps will be unitized rather than being shared between the two units. After the modifications are completed, one 100% capacity MDAFW pump will provide flow to both SGs in Unit 1 and the other 100% capacity MDAFW pump will serve the Unit 2 SGs. As part of the EPU modification, the new pumps will have a flow control valve on each of the two individual SG flow paths from the MDAFW pump. The two flow control valve setpoints will be set to initially provide each SG with approximately one-half of that unit's MDAFW pump flow.

The AFW system for each unit will consist of one turbine-driven pump system and one electric-driven pump system, pump suction and discharge piping, and the controls and instrumentation necessary for operation of the system. The system is provided to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of power and normal heat sink. Feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The auxiliary feedwater system is designed as a Seismic Class I system. A backup supply of auxiliary feedwater can be provided from the Seismic Class I portion of the service water system by automatically positioning remotely-operated valves or manually position the valves from the control room. See Figure 2.5.4.5-1

The auxiliary feedwater system redundancy is provided by using two diverse pumping systems two different sources of power for the pumps, and two sources of water supply to the pumps (one safety related and Seismic Class I (service water) and one non-safety and non-Seismic Class I (CST)). The system is categorized primarily as safety related, Seismic Class I and is designed to ensure that a single active failure will not adversely affect the reliability of function of the system.

One AFW pump system for each unit utilizes a steam turbine-driven pump with the steam capable of being supplied from either or both steam generators. This system is capable of supplying at least 275 gpm of feedwater to a unit at the lowest SG safety valve pressure setpoint. The EPU required flow, 275 gpm, is well within the capacity of the TDAFW pump. As part of the EPU implementation, the position of the throttle valves on the individual SG flow paths from the TDAFW pump will be set for the EPU required flow. The feedwater flow rate from the turbine-driven auxiliary feedwater pump depends on the throttle position of these MOVs. Check valves are provided to help prevent backflow when the pumps are not in service. The pump drive is a single-stage turbine, capable of quick starts from cold standby and is directly connected to the pump. The turbine is started by opening either one or both of the isolation valves between the turbine supply steam header and the main steam lines upstream of the main steam isolation valves. These valves are motor-operated stop check valves which prevent reverse flow between the steam generators. The turbine and pump are normally cooled by service water with an alternate source of cooling water from the firewater system.

The other AFW pump system for each unit uses a motor-driven pump, each capable of obtaining its electrical power from a plant emergency diesel generator. Each pump has a capacity of at least 275 gpm of feedwater to a unit. The MDAFW pump has one flow control valve per steam generator. Both flow control valves fail open on loss of pneumatic pressure. Both flow control valves are provided with a backup pneumatic supply in the event of a loss of instrument air. This backup safety-related pneumatic supply also supplies the fail closed minimum recirculation air-operated valve. Operator action will continue to be required to control the minimum recirculation valve and the discharge flow control to a throttled position consistent with the decay heat requirements if instrument air (IA) is lost and the backup SR pneumatic supply is depleted (similar to the existing system). The backup pneunatic supply will be sized for 4 hours of operation and 10 full strokes. The system design will allow the MDAFW pump to continue to run (prevent pump damage) and feed the steam generators without local manual action for beyond design basis events. For single failure, loss of the safety related pneumatic supply would be considered loss of the pump system.

Where required, DC power required to support operation of the MDAFW pump (e.g, control power to the 4 kV switchgear) is diverse from the DC supply associated with the TDAFW pump.

Thus, each unit will have one 100% capacity unitized MDAFW pump system in addition to the existing 100% capacity unitized TDAFW pump system.

Each of the two unitized MDAFW pumps will be installed in separate rooms in the 8' elevation of the primary auxiliary building (PAB). The TDAFW pumps remain in their present locations in the 8' elevation of the Control Building (CB).

The suction on all the AFW pumps is normally aligned to the Condensate Storage Tanks (CSTs). The current design relies on either operator manual action to stop the AFW pumps on low CST level auto-trip or low suction pressure. It then requires the plant operators to remote-manually open the Service Water (SW) valves to the AFW pump suctions and restart the AFW pumps to provide long-term cooling. The EPU modification will automatically open the SW supply valves to the AFW pump suctions on low AFW suction pressure. Additionally, a low suction pressure trip will still protect the pump if the automatic switchover does not occur. Auto-switchover eliminates a 5-minute interruption in AFW flow and eliminates a number of operator actions due to external events that may damage the suction piping.

In the pre-EPU design, one suction header is routed from the CSTs to the 8' elevation of the control building wherein branch lines are provided to each of the MDAFW and TDAFW pumps. The EPU modification will retain this suction header for the TDAFW pumps and it will add a suction header with ties in into the existing suction piping from the CSTs to both the 350 Hp MDAFW pumps.

The AFW system will continue to perform at EPU the safety-related functions discussed below. The primary impact of EPU on the AFW system is the increased heat removal requirement during abnormal, transient and accident conditions, which requires a higher AFW flow rate and an increase in the minimum required CST volume.

The safety-related portions of the AFW system are designed as Seismic Class I, and are capable of withstanding design basis earthquake accelerations without a loss of system performance capability.

The AFW system is designed so a single active failure will not disable more than one pump system in each unit. Each of the two AFW pump systems (i.e., a TDAFW pump and a MDAFW pump) in each unit has some shared discharge piping with instrumentation and controls (I&C) necessary for operation of the pump system. The two MDAFW pumps (one per unit) share a CST suction header. The two TDAFW pumps (one per unit) share the second CST suction header. In addition, the two Standby Steam Generator (SSG) pumps share the second CST suction header with the TDAFW pumps.

The AFW system will automatically start and deliver adequate AFW system flow to maintain adequate SG levels during anticipated plant transients that result in a loss of the main feedwater system. Such transients include loss of normal feedwater (LONF) and Loss of Non-Vital AC power (LOAC) events. See LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow, and Section 2.8.5.2.2, Loss of Non-Emergency AC Power to the Station Auxiliaries, respectively. LONF and LOAC are time-sensitive to AFW system start-up. The limiting AFW transient is a LONF without a concurrent LOAC since the reactor is not tripped, continuing to add 100% power to the primary loop, until a low-low SG level reactor trip occurs. Redundancy is provided by two 100% pump systems using diverse power sources. The design capacity of each pump system ensures that on the limiting LONF event, with a failure of one AFW pump system adequate RCS heat removal will be maintained to prevent the pressurizer from going solid. Unitizing the MDAFW pumps eliminates the control room operator action on dual unit AFW actuations (e.g., LOAC) to balance the MDAFW pump flows between units.

Similarly, the AFW system will automatically start and deliver sufficient AFW system flow to maintain adequate SG levels during accidents. Such accidents include Steam Generator Tube Rupture (SGTR, LR Section 2.8.5.6.2) and Main Steam Line Break (MSLB, LR Section 2.6.3.2). Although operator action is still required to isolate the AFW lines to a faulted generator following a MSLB or ruptured SG following a SGTR, the addition of flow control valves on the individual MDAFW SG discharge headers automatically maintains the flow setpoint to the faulted or ruptured SG from the MDAFW pumps. Although the AFW system is credited for the plant recovery and cooldown following a small break loss of coolant accident (LR Section 2.8.5.6.3.3), it is not assumed during the initial, short-term transient.

The former shared MDAFW pump system will not be removed. They will be retained in their existing location (the Control Building AFW pump rooms) and be redesignated as SSG trains. Their present piping arrangement will be maintained. This allows the "A" train SSG to feed the Unit 1 and Unit 2 "A" SGs and the "B" train SSG to feed the Unit 1 and Unit 2 "B" SGs. However, with the manual cross-connect between the SSG discharge headers open, either SSG pump can feed any SG for beyond design basis and off normal events. Since the SSG pumps will normally take suction from the CSTs and discharge to the AFW headers, the SSG train, including the pumps, pipes, and valves, will continue to meet the same piping Seismic Class I requirements as the unitized AFW pump systems. All AFW System automatic start signals on the SSG trains will be removed. Instead, all the controls for the SSGs and their associated valves will be limited to manual operation.

The SSG trains can be used to support unit startups and planned shutdowns, thus reducing the duty on the AFW pumps. The SSG pumps will be credited in the probabilistic risk assessment (PRA) to improve the overall reliability of emergency feedwater to the steam generators. To support emergency use, the SSG pumps will be powered from safety-related AC power.

The SSG pumps will not be automatically loaded to the EDG on a loss of AC and, if running, will be stripped upon an AFW initiation signal or diesel safeguards sequence signal for the associated unit. This feature is used to control loading on the EDG and 480V buses and to prevent excess flow to a faulted steam generator in a main steam line break or steam generator tube rupture event. To prevent inadvertent starting of an SSG pump while the new MDAFW pumps are operating, restart of a tripped SSG pump requires administrative controls and manual action by the operator. To prevent inadvertent bypass, indication is provided on the main control board if this feature is administratively bypassed or taken out of service.

Table 2.5.4.5-1 Auxiliary Feedwater NUREG-0800 Functional Comparison

	NUREG-0800 Attribute	PBNP Functional Equivalency
1.	The failure of non-essential equipment or components does not affect essential functions of the system	• Functionally Equivalent • Failure of CST did require Operator Action but this operation is proposed to be automated • Existing Heating Ventilation and Air Conditioning (HVAC) system is credited
2.	The system is capable of withstanding a single active failure	• Functionally Equivalent • AFW system is proposed to be unitized and single active failure proof
3.	The system has diverse motive power sources and can meet performance requirements with either of the assigned power sources	• Functionally Equivalent • MDAFW pump with AC power and AC and limited DC controls • TDAFW pump with steam power and DC controls different than MDAFW pump
4.	The system design precludes fluid flow instabilities	• Functionally Equivalent • Address in system mechanical design

	NUREG-0800 Attribute	PBNP Functional Equivalency
5.	System leakage can be detected, collected, and controlled and isolated	• Functionally Equivalent • Valves and indications will be provided to provide isolation in the event of excessive leakage or component malfunctions
6.	There are provisions for operational testing	• Functionally Equivalent • Full flow testing to the CST and SG available for MDAFW
7.	Instrumentation and control features are provided to verify that the system is operating in an acceptable mode	• Functionally Equivalent • Pump Suction Pressure Regulatory Guide (RG) 1.97 (Reference 7) Type D, Category 2 • Pump Discharge Pressure RG 1.97 Type D, Category 3 • Pump Flow RG 1.97 Type D,Category 2 • AFW Flow to each SG RG 1.97 Type A, Category 2 • CST Level RG 1.97 Type A, Category 1 • SG water level (wide range) RG 1.97 Type D, Category 1 • SG water level (narrow range) RG 1.97 Type A, Category 1
8.	The system can automatically initiate auxiliary feedwater flow upon a system actuation signal	• Functionally Equivalent • Operator action is currently required to balance MDAFW flow between units This is eliminated with proposed system

	NUREG-0800 Attribute	PBNP Functional Equivalency
9.	The system satisfies the recommendation of Regulatory Guide (RG) 1.62 (Reference 4) for capability to manually initiate protective action by the AFWS	• Functionally Equivalent • AFW pump systems can be manually initiated
10.	Designed to terminate auxiliary feedwater flow to a depressurized steam generator and to provide feedwater to the intact steam generator automatically. Alternatively operator action may be relied upon to isolate the depressurized steam generator	• Functionally Equivalent • Operator action still required to isolate AFW to faulted SG; however, the addition of Flow Control Valves (FCVs) on MDAFW pumps systems reduces flow to faulted SG and increases flow to non-faulted SG. EPU analysis demonstrates acceptable containment response.
11.	The system possesses sufficient auxiliary feedwater flow capacity to achieve a cold shutdown and decay heat removal	• Functionally Equivalent to existing system • Either safety grade AFW pump system capacity of 275 gpm is sufficient.
12.	Technical specifications assure the continued reliability of the AFWS during plant operation	• Functionally Equivalent • Eliminate sharing of MDAFW pumps. • Revised TS provided
13.	The system design meets the generic short- and long-term (GS, GL) recommendations identified in NUREG 0611 (Reference 5).	• Functionally Equivalent • Documented in GL 81-14 NRC and licensee correspondence (Reference 3) • Resolution to GS-1 and GL-4 improved

	NUREG-0800 Attribute	PBNP Functional Equivalency
14.	An AFWS reliability analysis is performed as required by Three Mile Island (TMI) Action Plan Item II.E.1.1 of NUREG-0737 (Reference 6) and 10 CFR 50.34(f)(1)(ii) for applicants subject to 10 CFR 50.34(f).	• Functionally Equivalent • AFW System Study Estimated Unavailability to be <1E-4
15.	Design meets TMI Action Plan Item II.E.1.2 of NUREG-0737 for the automatic and manual initiation of the AFWS and 10 CFR 50.62(c)(1) for automatic initiation of the AFWS in an anticipated transient without scram (ATWS).	• Functionally Equivalent Both AFW pumps systems are automatically initiated on • Low-low water level in either steam generator • Loss of both 4.16 kV buses supplying the main feedwater pump motors • Safety Injection sequence • ATWS Mitigation System Activation Signal (AMSAC). AMSAC signal is generated on a loss of normal feedwater at power levels above approximately 40%, or • AFW pump systems can also be manually initiated from control room or from local location outside the control room
16.	The system design permits operation at hot shutdown for at least four hours followed by cool down to the residual heat removal (RHR) cut-in temperature from the control room with only safety grade equipment, assuming the worst-case single active failure in accordance with Branch Technical Position (BTP) 5-4	• Functionally Equivalent • SW will auto transfer if necessary • PBNP safe shutdown is hot shutdown • Proposed System will meet Current Licensing Basis (CLB)
17.	AFWS diversity and performance are reviewed for decay heat removal capability and station blackout capacity	• Functionally Equivalent • Diversity is provided by AC powered MDAFW pump system and TDAFW with DC powered controls

	NUREG-0800 Attribute	PBNP Functional Equivalency
18.	Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC).	Not Applicable (COL related) - In compliance with current IST requirements
19.	COL Action Items and Certification Requirements and Restrictions	Not Applicable
GEN	"A typical system is assumed which has redundant auxiliary feedwater trains, with a 50% capacity motor-driven pump in each train feeding directly to the steam generators, and a 100% capacity steam turbine-driven pump" "The 50% capacity pump should have sufficient capacity for decay heat removal following any accident or transient although cool down to RHR cut in temperature may take longer than design."	• Not typical • One 100% TDAFW pump • One 100% MDAFW pump
GEN	SRP 10.4.9 Section III, 1, G: Design features have been incorporated to provide for <u>automatic</u> switchover to the safety-related water supply without an interruption in water flow	• Functionally Equivalent • AFW pump systems auto-transfer • New system risk improvement feature

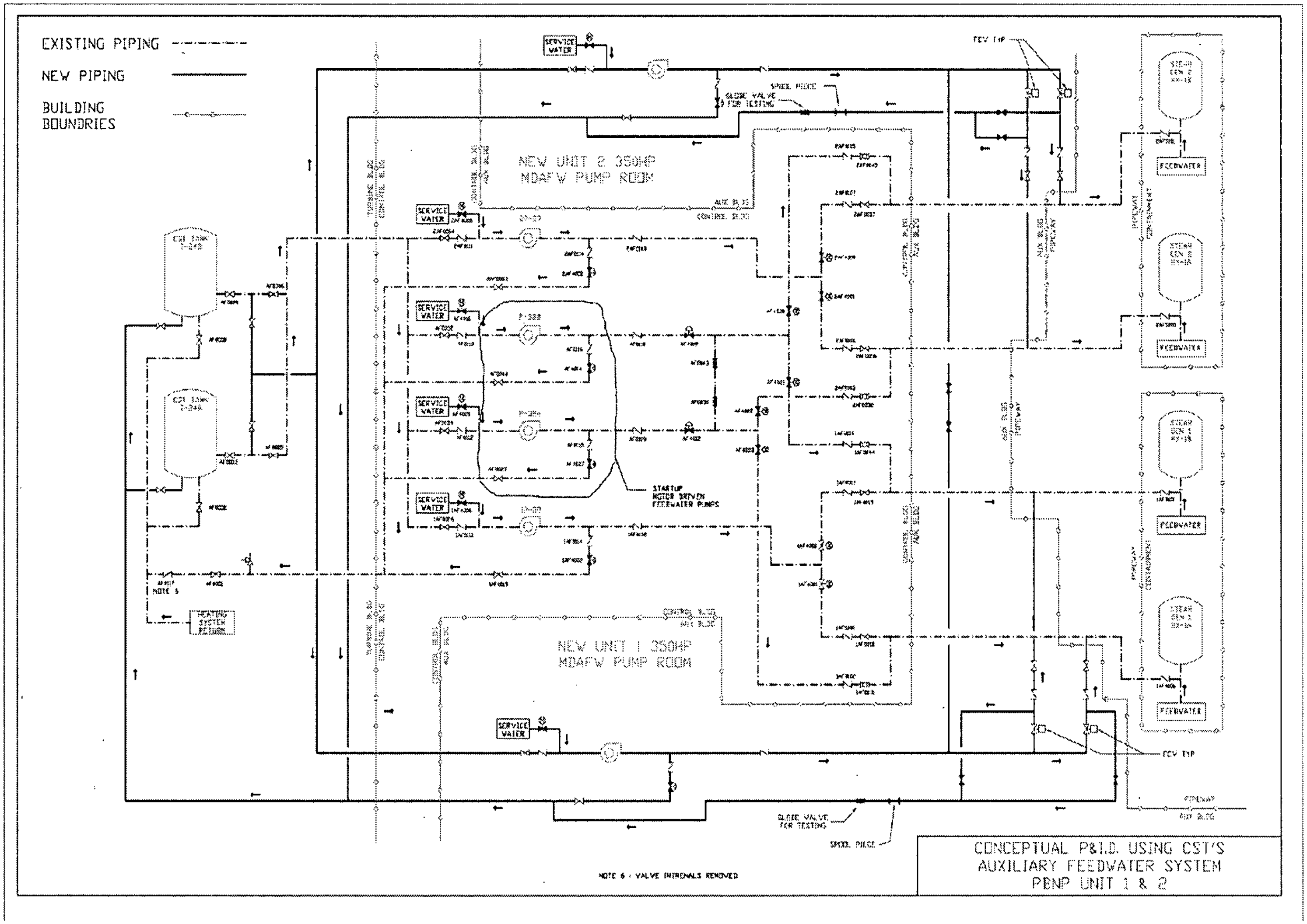


Figure 2.5.4.5-1 Conceptual Auxiliary Feedwater System Design

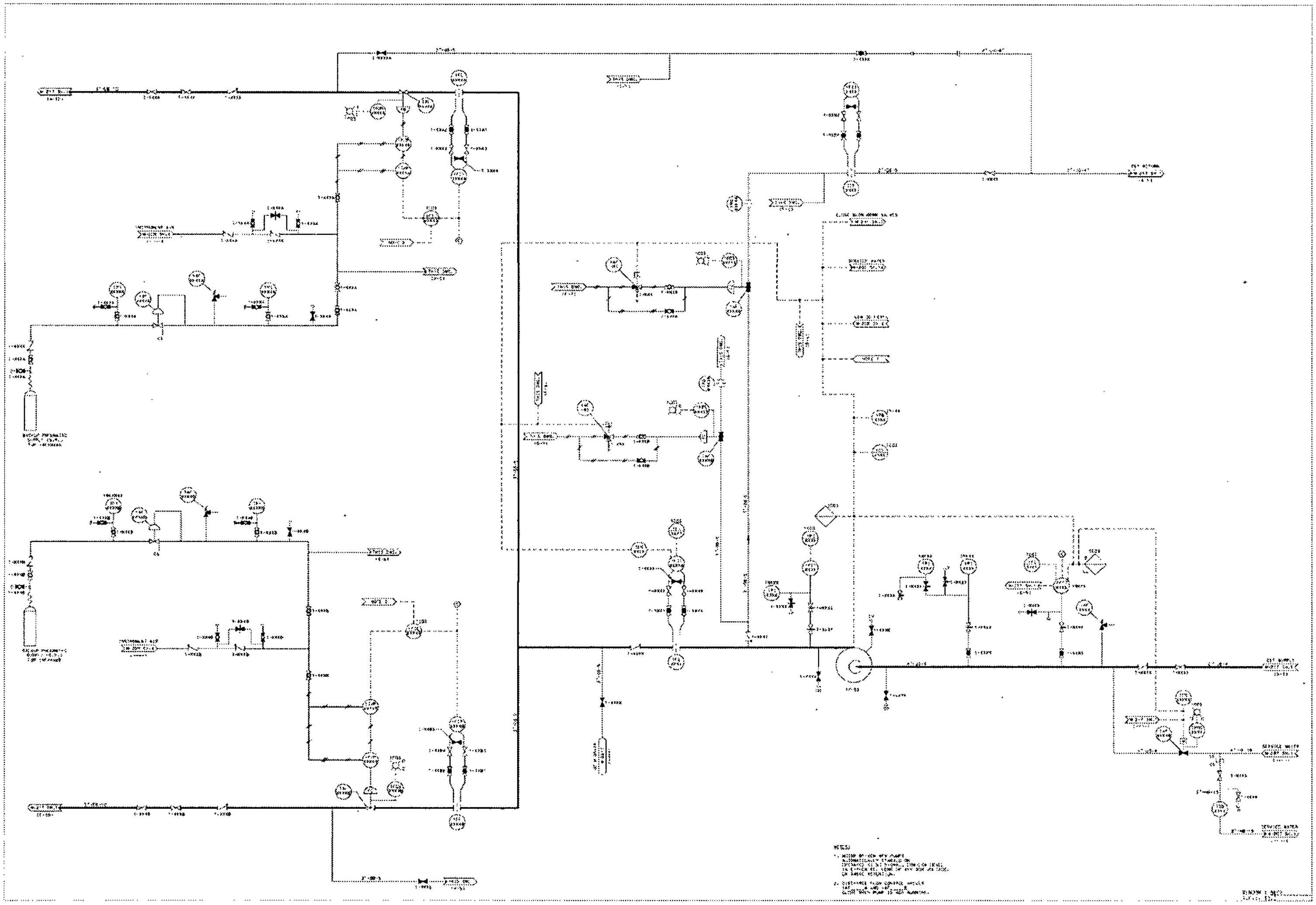


Figure 2.5.4.5-2 Conceptual Auxiliary Feedwater System Instrumentation Design

Description of Analyses and Evaluations

The evaluations compared the design parameters of these new pumps and components with the EPU conditions in conjunction with the following design aspects.

- Required flow rates/pump capabilities
- Design versus operating pressure/temperature of piping and components
- Water supplies/sources
- Pump design and performance

The following Licensing Report Sections also address the AFW system, piping or components:

- The electrical plant impact due to the AFW modifications and due to EPU are addressed in LR Section 2.3.2, Offsite Power System, LR Section 2.3.3, AC Onsite Power System, and LR Section 2.3.4, DC Onsite Power System.
- Piping / component supports and water hammer effects due to EPU are addressed in LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports. However, as discussed later in this section, AFW piping changes are required, and the modification process will confirm that all piping changes required by the EPU AFW modification will conform to the existing design basis.
- The EPU impact on the steam supply to the TDAFW pump is discussed in LR Section 2.5.5.1, Main Steam.
- The postulated transient and accident scenarios assuming EPU conditions and the modified AFW system are discussed in LR Section 2.8.5, Accident and Transient Analyses. Specifically LR Section 2.8.5.2.2, Loss of Non-Emergency AC Power to the Station Auxiliaries, LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow, LR Section 2.8.5.6.2, Steam Generator Tube Rupture, LR Section 2.6.3.2, Mass and Energy Release Analysis for Secondary System Pipe Ruptures, and LR Section 2.8.5.7, Anticipated Transients Without Scram. LR Section 2.8.5.6.3.3, Technical Evaluation – SBLOCA credits AFW for the recovery and cooldown phase, but not for the immediate short-term transient.
- The EPU impact to Station Blackout (SBO) is discussed in LR Section 2.3.5. During an SBO, only the TDAFW pump system is available. The EPU impact is an increase in the minimum required Condensate Storage Tank (CST) level and TDAFW Pump system pump system flow rate. The change to CST level will be implemented through a change to Technical Specification (TS) Section 3.7.6. As discussed later in this section, the flow rate is met without requiring any rerate or change to the TDAFW pump system, other than resetting the TDAFW pump discharge throttle valve setpoints for the higher EPU flow requirement. Also as discussed later in this section, the AFW system modifications and operation at EPU do not increase the TDAFW room heat loads during an SBO.
- The EPU impact on the operation of the AFW system during Appendix R fire scenarios is discussed in LR Section 2.5.1.4, Fire Protection, relative to decay heat removal, achieving hot/cold shutdown and operator actions. The AFW System modification will improve meeting Appendix R separation requirements by locating the new MDAFW pumps in a separate fire

area than the TDAFW pumps. Power cable routing, DC control power cables and motor control center designation will be selected to ensure separation of the TDAFW and MDAFW pump systems. The modification process will verify that the AFW Appendix R requirements are met for changes made.

- The EPU impact on protection against dynamic effects of missiles, pipe whip and discharging fluids is discussed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures. The only portion of the AFW System that is considered high energy is the MS line to the TDAFW pump system. As discussed later in this section, the EPU modifications do not include any piping or valve changes to the steam supply to the TDAFW pumps. The modification process will verify that any new or relocated AFW equipment meets the existing design basis protection from the consequences of high energy lines missiles and breaks.
- The EPU impact on Instrumentation & Control (I&C) is discussed in LR Section 2.4.1. As discussed later in this section, the AFW System modification will maintain the same I&C design basis for the TDAFW pumps and for the new MDAFW pumps with the exception of (a) upgrading the suction transfer for the AFW pumps on low suction header pressure to the SW supply from manual to automatic (b) changing the MDAFW pump system signals to reflect a unitized design, and (c) changing the MDAFW pump system flow control scheme. Control Room changes are required to incorportate the new MDAFW pump controls and flow indication. The main control room changes for human factors are discussed in LR Section 2.11.1, Human Factors
- The EPU impact on environmental qualification of electrical components is discussed in LR Section 2.3.1, Environmental Qualification of Electrical Equipment. The modification process will verify that any new or relocated AFW equipment meets the EQ design basis.
- The EPU impact on safety-related valves and pump is discussed in LR Section 2.2.4, Safety-Related Valves and Pumps. The modification process will verify that the new MDAFW pump system equipment meets the existing design and testing requirements. This includes adding the MDAFW pump, flow control valves, check valves, service water suction valve, and minimum recirculation valve to the testing program. The existing TDAFW pump system rating is adequate for EPU and the physical changes to the TDAFW pump system are limited to valve repowering. Therefore, the design and testing of the TDAFW pump system valves and pump are not impacted with the exception that the revised, maximum allowed pump degradation will be incorporated into the testing program.
- The EPU impact on protection against internal missiles and turbine missiles is discussed in LR Section 2.5.1.2.1, Internally Generated Missiles, and LR Section 2.5.1.2.2, Turbine Generator, respectively. The modification process will verify that any new AFW equipment meets the existing design basis protection from the consequences of internal missiles.
- The EPU impact to the Control Building AFW Pump Area Ventilation System (VNAFW) is provided in LR Section 2.7.6, Engineered Safety Feature Ventilation System. The EPU impact of the AFW system on the Primary Auxiliary Building (PAB) ventilation is discussed in LR Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems.

Because of its low usage factor, the AFW piping is not subject to Flow Accelerated Corrosion monitoring and, therefore, it is not discussed in LR Section 2.1.8, Flow-Accelerated Corrosion.

Results

The following subsections evaluate the specific AFW system and component licensing, design and performance capabilities while at EPU conditions.

General Design Criteria

FSAR Section 7.5.4.2 describes the Indications and Controls Provided Outside the Control Room. This requires having capabilities outside the control room so plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the control room.

The implementation of EPU will not affect the capability of the AFW system to support decay heat removal following control room evacuation. The AFW modification will maintain the required local controls for the MDAFW and TDAFW pumps and associated valves. The AFW modification will ensure that either AFW pump system can supply the required AFW flow from outside the control room.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to requirements of PBNP GDC 37 to provide high pressure feedwater to the SGs in the event of an accident.

The AFW system is considered one of the steam power conversion systems that together with the residual heat removal system, transfer the heat from the reactor core at a rate such that design limits of the fuel and the primary system coolant boundary are not exceeded. Suitable redundancy is provided in the AFW pumps, piping paths and valves. The AFW system is able to operate with either onsite or offsite power systems. The AFW system will continue to provide these same capabilities after implementation of EPU as demonstrated by the system and component evaluation results described below and by the analysis results discussed in LR Section 2.8.5, Accident and Transient Analyses, using the AFW systems to mitigate the postulated transient and accident scenarios.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 41, to provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. The AFW System is designed with sufficient mechanical and electrical redundancy such that a single failure of an active component, in the system, can be accommodated without loss of the overall AFW System safety-related functions. The implementation of EPU does not affect the capability of these systems to perform this function as demonstrated by the system and component evaluation results described below and by the analysis results discussed in LR Section 2.8.5, Accident and Transient Analyses, using the AFW system to mitigate the postulated transient and accident scenarios. The modification process will confirm that the AFW System continues to meet the single failure of an active component requirement.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirements of PBNP GDC 40, that safety-related structures, systems, and components important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures, as described in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, LR Section 2.5.1.3, Pipe Failures and LR Section 2.5.1.2.1, Internally Generated Missiles.

PBNP GDC 4 allowed that reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. However, since the Unit 1 and 2 CSTs are normally cross-connected and the SW System is a shared system, PBNP GDC-4 remains applicable to the AFW suction sources.

Auxiliary Feedwater Flow Rates/Auxiliary Feedwater Pumps Design Capabilities

The AFW system flow rate requirements are listed in Table 2.5.4.5-2, Auxiliary Feedwater Flow Rate Requirements. The key AFW transients are described below. Unitizing the MD pumps has two fundamental changes. First, by unitizing the MDAFW pump systems, the unavailability of a MDAFW pump system affects only one unit. Second, eliminating shared MDAFW pumps reduces the delay time required to achieve the required flow from these pumps since the operator steps to balance the flow between the two units are eliminated. The remaining delay time is due to equipment response times (e.g., diesel starts, pump ramp-up times, instrument delays, and valve position changes).

FSAR Section 14.1.10, Loss of Normal Feedwater, makes the following assumption regarding AFW flow for the pre-EPU analysis:

- The AFW system provides 200 gpm of flow split between the two SGs. The assumption of split flow is slightly more conservative than 200 gpm of flow to a single SG.

The current AFW analysis limiting event is a dual unit loss of all AC. For the revised EPU analysis the limiting event is a single unit loss of normal feedwater (LONF).

For EPU, either AFW pump system-can provide the required 275 gpm flow split between the affected unit's two SGs. Therefore, only the unit's MDAFW or TDAFW pump system is required.

FSAR Section 14.1.11, Loss of All AC Power to Station Auxiliaries, makes the following assumption regarding AFW for the pre-EPU analysis:

- The AFW system provides only 200 gpm of flow to a single SG.

For EPU, either AFW pump system can provide the required 275 gpm flow split between the affected unit's two SGs. Therefore only the unit's MDAFW or TDAFW pump system is required.

As stated in FSAR Section 10.2.3, Auxiliary Feedwater System - System Evaluations, during an SBO event, only the TDAFW pumps would be available for decay heat removal. The TDAFW pumps can supply feedwater to the SGs without an AC power source.

For EPU, the required TDAFW pump system SBO flow rate is bounded by the flow rate for the limiting AFW System transient, a LONF.

As stated in FSAR Section 10.2.1, Auxiliary Feedwater System - Design Basis, in the event of plant fires, including those requiring evacuation of the control room, the AFW system shall be capable of manual initiation to provide feedwater to a minimum of one SG per unit at sufficient flow and pressure to remove decay and sensible heat from the reactor coolant system over the range from hot shutdown to cold shutdown conditions. The AFW system is capable of supporting achievement of cold shutdown within 72 hours.

The flow requirement for fires, after EPU, is bounded by the LONF. To increase the reliability of feedwater to the SGs following a fire, the MDAFW pumps are being located in a different building and fire area than the TDAFW pumps.

To satisfy the EPU AFW flow requirements listed in Table 2.5.4.5-2, modifications will be implemented on the MDAFW pump systems as discussed in this LR. The modification process will confirm that the required flow can be met with the new MDAFW pumps and their flow control valves, and the final piping routing. The present rating for the TDAFW pump systems already exceeds the required EPU flow.

TS 3.7.5 will be revised to incorporate the new AFW System design as proposed in Attachment 2.

For beyond design basis events, an evaluation of the SSG pumps was performed using better-estimate (B/E) parameters. The required AFW flow at EPU power assuming B/E parameters is 220 gpm to one SG. The B/E analysis assumes nominal I&C setpoints and plant parameters as opposed to the limiting values. It credits the Atmospheric Dump Valves, and assumes a 5-minute delay in flow initiation (10 minutes for LOCA). The original two (250 Hp) pump systems redesignated as SSG trains, can be aligned to feed steam generators in either unit by remote-manual operator action. A single SSG assuming no pump degradation can provide 220 gpm flow to one SG. The use of the original SSG trains for remote manual operation provides a positive contributor to system reliability.

Design vs. Operating Pressures and Temperatures - Auxiliary Feedwater System

EPU does not require any changes to the CSTs or to the service water pumps that change the operating pressure or temperature to the piping on the suction side of the pumps.

The only change required to the AFW pressure rating on the discharge side of the pumps is limited to the new piping that will be subject to the shutoff head from the new MDAFW pumps. The new piping and valves will require a higher pressure rating. The final piping design will be established during the modification process ensuring adequate pressure rating of all new piping and components. Existing AFW discharge piping and valves will remain bounded by the original design pressure. The pressure rating on the TDAFW discharge piping is not affected because the TDAFW pump does not require rerating for EPU. The existing piping design pressure downstream of the last AFW isolation valve (manual outside containment isolation valve) is unchanged, since this is limited by the Steam Generator Main Steam Relief valves. EPU does not change the design temperature of the piping on the discharge side.

Flow Velocities and Erosion/Corrosion Concerns - Auxiliary Feedwater System

The impact of EPU operation on the required AFW system flow rate is the increased required flow from 200 gpm to 275 gpm. However, AFW flow is short-term since it is normally limited to plant accidents, other safe shutdown transients, and testing. In addition, since decay heat drops quickly, the maximum flow rate is only during the early part of the transient. Since there is no significant potential for erosion/corrosion, the AFW System is not part of the PBNP flow accelerated corrosion (FAC) program.

Auxiliary Feedwater System Water Supply - Condensate Storage Tanks

AFW pumps are normally aligned to take suction from the two CSTs which are shared by both units. The present plant licensing bases dictate that in the event of a SBO, the minimum volume in the CSTs must be sufficient to maintain each unit in hot standby mode for one hour. The CST required minimum volume for each unit will be increased from 13,000 to 15,410 gallons assuming both CSTs are available. If only one CST is available for both units, the required minimum volume is increased from 26,000 to 30,820 gallons. The required volume at EPU based on NUMARC 87-00, Revision 1, for one hour is 13,986 gallons (which is rounded up to 14,000). Thus, the revised volume provides a 10% margin (1410 gallons) for supporting an orderly transfer to SW after 1 hour. The CST nominal and maximum storage capacity is not being increased.

The minimum CST level is based upon the required volume level plus the level required for level instrumentation inaccuracy and level to prevent vortexing. Since the CSTs are on the 26' elevation and the AFW and SSG pumps are on the 8' elevation, the CST minimum level to prevent vortexing provides adequate NPSH for the AFW pumps.

TS 3.7.6 will be revised to incorporate the new CST volume requirement. This will also require setpoint changes for CST low level alarms and low-low level alarms. These changes will be implemented by the plant modification process prior to EPU implementation. The SR 3.7.6.1 value to be inserted will be provided to the NRC as a supplement to this LAR by July 30, 2009.

Alternate Water Supplies – Service Water and Fire Protection Water

The Service Water (SW) System provides a safety-grade water source to each AFW pump suction, if the non-seismic CSTs are depleted or fail. The source of water for the SW pumps is Lake Michigan. The present design basis requires manual realignment of AFW to SW on a low CST suction line pressure. The EPU modification will make this realignment to SW automatic. The suction pressure automatic transfer setpoint information and proposed TS Table 3.3.2-1 Function 6e will be provided to the NRC staff on or prior to July 30, 2009 (Commitment 1 of Attachment 4).

If the CSTs become unavailable, the SW system provides the water source to the AFW pump suctions. EPU does increase the required flow. However, this has a low impact to the SW system flow requirements since maximum SW demand occurs when decay heat removal is through the RHR heat exchangers rather than when the AFW system and SGs are credited.

As stated in FSAR Section 10.2.2, Auxiliary Feedwater System - System Design and Operation a loss of main feedwater pumps initiated by a seismic event could also result in a failure of the CSTs because they are not Seismic Class I. NUREG 0611 Item GL-4 requires either AFW pump trip or AFW suction auto-transfer on a loss of the non-safety CST (Reference 2). With the modified design the credited pump protection will be through an automatic, low suction pressure transfer to SW. The AFW pump will be tripped if the suction pressure to that pump is not re-established following the auto-transfer. This is indicative that the SW valve for that pump failed to open.

No additional SW flow rate is required during LOCA and MSLB accidents while operating at EPU conditions. The CST is assumed to be available for AFW pump supply for LOCA or MSLB accidents in the SW system model. Therefore, the increased flow rate for AFW under EPU conditions will not affect the SW flow rate to the Containment Fan Coolers.

During normal operation, a decrease in required flow rates will occur due to removal of SW cooling to the new main feedwater and condensate pumps. A small increase in flow will be required by the new isophase bus duct cooler. Therefore, additional margin will be available in the turbine generator branches of SW.

The AFW system requires support from the Fire Protection System to provide an automatic backup cooling water supply to the TDAFW pump bearing coolers, when they are required to operate, in the event that the SW system is inoperable (such as during the initial one-hour phase of a SBO). There is no change in this requirement due to EPU. The MDAFW pumps have a shaft mounted fan that eliminates the need for an external fluid to provide shaft or seal cooling.

Auxiliary Feedwater Pump - Net Positive Suction Head (NPSH)

The higher EPU AFW flow increases the AFW pump required net positive suction head (NPSH), but the available NPSH will remain adequate. The present design has one suction header between the CST and the four individual branch lines in the CB AFW pump rooms. As part of the EPU modifications, a second CST suction header will be provided. The original CST suction header will serve the two TDAFW pumps and the new CST suction header will serve the two MDAFW pumps. With separate suction headers for the TDAFW pump and for the MDAFW pump, the EPU flow per header will be lower than the pre-EPU flow in the single header thus reducing the pressure drop due to flow.

The limiting available NPSH condition occurs when the suction is from the CSTs since it relies only on static head. The CST is assumed to be available for AFW pump supply for LOCA or MSLB accidents in the SW system model. The SW alignment is not limiting since the AFW suction is then from a SW pump discharge header. The minimum available NPSH occurs when the CSTs are at their lowest level. The modification process will confirm that adequate NPSH is maintained.

Pump Brake HP Requirements - Auxiliary Feedwater Pumps

The brake HP required by the MDAFW pumps will be higher for EPU conditions. The new MDAFW pumps will be provided with a 350 Hp motor and will be powered by the 4.16 kV busses rather than the original 480 V bus. The EPU evaluation shows that the motor will operate within its nominal capacity.

The flow requirement for the TDAFW pump for EPU conditions has increased, but remains within the capacity of the TDAFW pump and turbine driver. No modifications are required to the TDAFW turbine driver.

Auxiliary Feedwater Safety-Related Valves

Due to the AFW System physical modifications which will be implemented, the modification process will verify that all the valves on the new MDAFW pump system will meet the design basis for flow, pressure and temperature. Rerating of any TDAFW pump system or SSG train valves is not required.

Each AFW pump system and SSG train has either an air accumulator or bottled nitrogen system as back-up for the air-operated valves in that pump system/train in case of a loss of the instrument control air system. Following the AFW modification, there will be a total of four independent back-up, safety-related air or nitrogen systems - one for each of the four AFW pump systems. The air accumulator on each TDAFW pump system is unchanged. It provides back-up air only to the TD pump's minimum recirculation valve. The nitrogen bottle system on each SSG train will be maintained. It provides compressed nitrogen gas only to that SSG train's pressure control and minimum recirculation valves. The back-up system for each new MDAFW pump system will feed the associated flow control valves and minimum recirculation valve. This ensures that any single failure in the back-up supply is limited to a single AFW pump system.

Standby Steam Generator Train Interface Requirements

The SSG trains are not safety-related since they are not credited for SG cooling in any of revised accident or transient analyses presented in LR Section 2.8.5, Accident and Transient Analyses. There is no sharing of pumps or active valves between the SSG trains and AFW pump systems. The only shared valves are (1) the manual valves at the CST outlet and (2) the inside-containment AFW check valve immediately before the AFW line tie-in to that SG's main feedwater line.

The piping and other pressure boundary components criteria imposed on the original MDAFW pump systems will be retained when the existing MDAFW pumps are converted to SSG trains. This is necessary since the SSG train suction and discharge lines tie into the AFW system suction and discharge piping. This includes retaining the existing seismic requirements and protection from severe weather, tornado effects, missiles, and HELBs. The mechanical portion of the SSG trains are enclosed on the 8' elevation of the safety-related Control Building.

Auxiliary Feedwater System I&C

The primary change to the MDAFW pump system is due to unitizing the AFW System; the MDAFW pump system will be initiated only by signals from its associated unit. The TDAFW pump system initiation signals are already unitized.

Following AFW system modification, the automatic initiation signals for the TDAFW and MDAFW pump systems will be:

- Low-low water level in either steam generator
- Loss of both 4.16 kV buses supplying the main feedwater pump motors
- ATWS Mitigation System Activation Signal (AMSAC). AMSAC signal is generated on a loss of normal feedwater at power levels above approximately 40%, or
- Safety Injection sequence

Both AFW pump systems as well as the SSG trains can also be remote-manually started. The SSG remote-manual control signals need not be safety-related; however, the design must ensure that any failure does not adversely affect the AFW controls or other safety-related controls. The

SSG trains (including valves) will not have automatic start signals. In addition, the automatic AFW initiation signal will automatically trip the SSGs. This automatic trip signal will be safety-related.

The low and low-low CST water level alarms will be maintained, but their setpoints will be adjusted to reflect the higher, usable volume required by the uprate. On a low-low suction line pressure, the suction to the AFW pumps will be automatically aligned to SW rather than tripped. The suction to the SSG train can only be remote-manually realigned to SW.

Auxiliary Feedwater System Electrical

For each unit the MDAFW pump system will be one AC train. For each unit the TDAFW pump system will be the opposite DC train. The Unit 1 and Unit 2 MDAFW pumps will be on separate AC trains and the Unit 1 and Unit 2 TDAFW pumps will also be on opposite DC trains. Some re-powering of the DC supplies may be necessary on the TDAFW pump trains. Each pump system will have two ways using opposite trained power to stop flow for events that require AFW flow to be terminated.

The existing 250 Hp, MDAFW pump systems, will maintain their present power sources. The pumps are powered from safety-related 480 VAC buses. One of the two trains is powered from Train "A" and it is capable of feeding the Unit 1 and Unit 2 "A" SGs. The second train is powered from Train "B" and it is capable of feeding the Unit 1 and Unit 2 "B" SGs. The AFW modification will, however, automatically strip them off the safety-related switchgear on a diesel safeguard sequence or AFW initial signal. This requirement extends to electrical components, such as the breaker on the SSG pump motor, to ensure that the actions required by the signal occur.

The increase MDAFW pump motor horsepower has been evaluated for it's effect on the EDG loading and fuel oil supply. The evaluation demonstrates that the EDG will continue to operate within it's design ratings and the fuel oil supply is adequate to support operation of the EDGs.

It should be noted that the SSG pumps are not required for steady-state power operation since their normal function is to support unit start-up or planned shutdown. When used for start-ups or planned shutdowns, the SSG trains would normally be aligned only to one unit. SSG train operation is not required following any LR Section 2.8.5 plant transient or accident since each of the two AFW pump systems can provide the required 275 gpm.

Auxiliary Feedwater Room Ventilation

The Control Building AFW pump room (8' elevation) contains the TDAFW pump and turbine and the 250 Hp SSG pumps. The Auxiliary Feedwater Pump Area Ventilation (VNAFW) discussed in LR Section 2.7.6, Engineered Safety Feature Ventilation System serves this area. Since the 250 Hp pumps will be redesignated as SSGs and concurrent operation of the TDAFW pump and the SSGs is not required, the ventilation design basis heat load during anticipated modes of AFW operation for this room can be reduced. During SBO, TDAFW heat load changes are not significant. The TDAFW pump system heat load is primarily from the MS line to the turbine, the turbine steam exhaust lines, and turbine casing. With EPU, the MS steam temperature at SBO conditions (zero power) remains unchanged. Since the maximum allowable CST temperature is not increased, the AFW piping temperature is unchanged. Pump bearing cooling (from the fire water system, powered by the fire water diesel) is unchanged with EPU. The remaining AFW heat loads are due to the DC powered components in the rooms. No TDAFW pump system components changes are being made except for repowering some DC powered valves. Heat load changes due to setpoint and cabling changes are considered insignificant. Therefore, the SBO TDAFW heat load increases due to EPU are not significant.

The new, MDAFW pumps and their 350 Hp motors will each be located in a separate room in the 8' elevation of the Primary Auxiliary Building (PAB). These rooms will be provided with a sufficiently large opening to the general area of the PAB, which is cooled by the VNPAB system and which is addressed in LR Section 2.7.5, Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems. The EPU modification will verify that adequate cooling is provided to ensure operability of the MDAFW pump and confirm that the licensing basis of the PAB ventilation is met. Since the AFW pumped fluids are from radioactively clean sources, there is no impact on the PAB air filtration requirements.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the AFW system are within the scope of License Renewal. The EPU AFW modification adds new components but does not introduce any new functions that would change the license renewal system evaluation boundaries. The changes associated with operating the AFW system at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Since this system does not operate during normal operation of the plant, increase in flow requirements due to EPU has minimal effect. Thus, no new aging effects requiring management are identified.

2.5.4.5.3 Conclusions

PBNP has assessed the affect of EPU on the AFW System. PBNP concludes that the assessment has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the Auxiliary Feedwater System to supply adequate water to the SGs to ensure adequate cooling of the core. PBNP finds that the Auxiliary Feedwater System will meet its design functions following implementation of the proposed modifications and EPU. Revisions to the AFW Technical Specifications are required to implement the revised AFW design. PBNP further concludes that the Auxiliary Feedwater System will continue to comply with PBNP GDCs 1, 2, 4, 11, 12, 37, 38, 40, 41 and 42. Therefore, PBNP finds the proposed EPU acceptable with respect to the Auxiliary Feedwater System.

2.5.4.5.4 References

1. NRC Safety Evaluation, Seismic Qualification of the Auxiliary Feedwater Point Beach Nuclear Plants Units 1 and 2, dated September 16, 1986

2. NUREG-0611, Generic Evaluation of Feedwater Transients and Small-Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants, U.S. Nuclear Regulatory Commission, dated January 1980

3. NRC Generic Letter 81-14, Seismic Qualifications for Auxiliary Feedwater Systems, dated February 1981

4. RG 1.62, Manual Initiation of Protective Actions, dated October 1973

5. NUREG-0611, Generic Evaluation of Feedwater Transients and Small-Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants, dated January 1980

6. NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980

7. RG 1.97, Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, Revision 2

Table 2.5.4.5-2 Auxiliary Feedwater Flow Rate Requirements

Parameter	Current Flow Rate (gpm)	EPU Flow Rate (gpm)
A. Required AFW flow rate for LONF (Loss of normal feedwater)	200 (one pump)	275 (one pump)
B. Better estimate AFW flow for LONF	NA	220 gpm (one pump to one SG)
C. Required AFW flow rate for LOAC (Loss of all AC power to the station auxiliaries)	200 (one pump)	275 (one pump)
D. Required AFW flow rate to each SG following a Station Blackout (SBO)	200	Bounded by LONF / LOAC
E. Assumed flow during ATWS events	800	400 and 800*
F. In the event of plant fires, including those requiring evacuation of the control room, AFW shall be capable of manual initiation to provide feedwater to a minimum of one SG at sufficient flow and pressure to remove decay and sensible heat from the Reactor Coolant System over the range from hot shutdown to RHR cut-in conditions	Bounded by LONF/ LOAC	{Bounded by LONF / LOAC}
G. Maximum Allowable AFW flows to the faulted SGs during a Main Steam Line Break (MSLB) for a variety of pumping combinations and postulated failures assumed in the MSLB analyses	400 to 540 (function of SG pressure)	619 to 1139 (function of SG pressure)
* Two cases were evaluated to bound AFW flow. Both met the acceptance criteria.		

Table 2.5.4.5-3 Auxiliary Feedwater System Pressure/Temperature Comparison

	Design Conditions		Maximum EPU Conditions	
	Pressure (psig)	Temperature (°F)	Pressure (psig)	Temperature (°F)
AFW Pump Suction piping from Condensate Storage Tank	50	100	<50 (Does not change for EPU)	100 (Does not change for EPU)
AFW Pump Suction piping from SW header	100	100	< 100 (Does not change for EPU)	100 (Does not change for EPU)
Discharge Piping for the TDAFW Pumps and SSGs including Recirculation Piping that may see pump shutoff head	1440	100	< 1440 (Does not change for EPU)	100 (Does not change for EPU)
Discharge Piping from MDAFW Pumps including Recirculation Piping that may see pump shutoff head	>1540 *	100	Approximately 1540*	100 (Does not change for EPU)
* The replacement MDAFW pump has higher shutoff head and will require that the new AFW piping may experience the MDAFW pump shutoff head be rated above 1440 psig. This will be done as part of the design modification process.				

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

2.5.5.1.1 Regulatory Evaluation

The Main Steam (MS) System transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The PBNP review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads).

The NRC's acceptance criteria for the main steam supply are based on:

- GDC 4, insofar as it requires that Structures, Systems and Components (SSCs) important-to-safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures.
- GDC 5, insofar as it requires that SSCs important-to-safety not be shared among nuclear power units unless it can be sown that sharing will not significantly impair their ability to perform their safety functions.
- GDC 34, insofar as it required that a Residual Heat Removal (RHR) system be provided to transfer fission product decay heat and other residual heat from the reactor core.

Specific review criteria are contained in Standard Review Plan (SRP), Section 10.3.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4, 5 and 34 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

The MS System is described in FSAR Sections 10.0, Steam and Power Conversion, and 10.1, Steam and Power Conversion System.

The MS System transports the steam produced in the steam generators to the main turbine for the production of electricity. This system provides heat removal from the reactor coolant system (RCS) during normal, accident and post accident conditions. It also provides steam for the turbine-driven auxiliary feedwater pumps, which can be obtained from either main steam line, upstream of the main steam isolation valves.

The MS system, via the atmospheric dump valves (ADVs), provides a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink, via the steam bypass system to the condenser, not be available. This is done in conjunction with the auxiliary feedwater (AFW) system providing cooling water from the condensate storage tank (CST) or the service water system. The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the steam dump system. Performance requirements for the ADVs are provided in PBNP Technical Specification 3.7.4 and associated Technical Specification Basis.

The steam lines from the steam generators up to and including the main steam line non-return check valves are Seismic Class I. A failure of any Class I main steam line, or malfunction of a valve installed therein, will not impair the reliability of the auxiliary feedwater system, render inoperative any engineered safeguard feature, initiate a loss of coolant condition, or cause failure of any other steam line.

In addition to the evaluations described in the FSAR, PBNP's main steam system was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER describes main steam in Section 2.3.4, Steam and Power Conversion Systems. The programs used to manage the aging effects associated with main steam are discussed in Section 3.4 of the SER.

2.5.5.1.2 Technical Evaluation

Introduction

The main steam system is described in FSAR Section 10.1, Steam and Power Conversion System. The system provides heat removal from the reactor coolant system during normal, accident, and post accident conditions. During off normal conditions, the system provides emergency heat removal from the reactor coolant system using secondary heat removal capability. System components are also credited for safe shutdown following station blackout events and some fire events.

The main steam system is designed to produce dry saturated steam in the steam generators and direct it to the high pressure turbine, as well as other steam driven components and auxiliary steam systems. The main steam system includes the steam piping, main steam safety valves, atmospheric dump valves (ADVs), main steam isolation valves, main steam non-return check valves, main steam flow venturis, crossover pipe dump valves, and other miscellaneous valves and piping. The main steam system also provides a flow path for steam from the steam generators to the condenser steam dump valves (CDVs), the turbine bypass system, which is discussed in LR Section 2.5.5.3, Turbine Bypass.

The reheat steam system is considered part of the main steam system for PBNP. The reheat system delivers steam from the high pressure turbine exhaust through the moisture separators reheaters and then to the low pressure turbine inlets. The system is designed to remove up to 70% of the moisture in the pre-separators prior to entering the moisture separator reheaters where the remaining moisture is removed, steam is dried and then superheated (using main steam) and sent to the low pressure turbines. The reheat system includes the pre-separators, the moisture separator reheaters, crossover piping steam dump, and piping associated with this equipment.

The main steam system design functions are:

- Supply steam from the steam generators to the main turbine, turbine-driven auxiliary feedwater pumps, moisture separator reheaters, main steam safety valves, air ejectors, building heating, atmospheric dump valves, condenser steam dump valves, and support heating of the turbine gland sealing system
- Control steam generator pressure during startup and shutdown and when the condenser is not available
- Provide over-pressure protection for the steam generators
- Provide a primary containment isolation boundary
- Provide for main steam line and turbine warm-up
- Provide a means to dissipate the heat generated in the Nuclear Steam Supply System during all modes of normal operation, transient and accident conditions

The reheat steam system design functions are:

- Moisture removal from the high pressure turbine exhaust steam via moisture pre-separators and moisture separators
- Supply superheated steam from the moisture separator reheaters to the low pressure turbines
- Provide main turbine/generator over speed protection by the crossover steam dump system

Description of Analyses and Evaluations

The main steam and reheat steam systems and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations were conservatively performed for an analyzed NSSS power level of 1806 MWt. The evaluations compared the existing design parameters of the systems/components with the EPU conditions for the following design aspects:

- Design pressure/temperature of piping and components

- Flow velocities
- Vibration due to increased flow
- Capacities, closure times and set pressures for the main steam isolation and non-return check valves, main steam safety valves and atmospheric dump valves
- Moisture removal capability, thermal performance, vibration and erosion/corrosion of the moisture separator reheaters
- Main steam supply capacity to the turbine-driven auxiliary feedwater pump and to other auxiliary loads, LR Section 2.5.4.5, Auxiliary Feedwater
- Main steam drain system capacity

Other evaluations of main steam and reheat steam systems and components are addressed in the following LR sections:

- Erosion/corrosion issues – LR Section 2.1.8, Flow-Accelerated Corrosion
- Piping/component supports – LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports
- Protection against dynamic effects, including missiles, pipe whip and discharging fluids – LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures
- Environmental qualification of the main steam isolation valves actuators – LR Section 2.3.1, Environmental Qualification of Electrical Equipment
- LR Section 2.2.4, Safety-Related Valves and Pumps
- Protection against internal missiles and turbine missiles – LR Section 2.5.1.2.1, Internally Generated Missiles and LR Section 2.5.1.2.2, Turbine Generator, respectively
- Safety related instrumentation – LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the main steam system are within the scope of License Renewal. EPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the main steam system at EPU conditions do not add any new or previously unevaluated materials to the system. To support operation at EPU conditions, the existing main steam isolation valve and non-return check valve internals are being modified. The valve disk material is being changed from carbon steel to stainless steel with stiffeners to prevent disk distortion associated with valve closure. The modified valves do not introduce any new materials to the valve pressure boundary, and the valve functions are unchanged. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for Aging Management Programs to account for the effects of EPU, although parameter changes will be made to the Flow-Accelerated Corrosion program (See LR Section 2.1.8, Flow-Accelerated Corrosion). Aging effects, and the programs used to manage the aging effects for the modified MSIVs will be addressed in the plant modification process.

Results

System Operating Conditions

Heat balances were developed to determine the steam cycle parameters while operating at the increased NSSS power level. Heat balances were developed for the current power level based on actual plant operating data and at the analyzed core power level of 1800 MWt. The EPU heat balances specify the required main steam flow rate at the high pressure turbine inlet throttle pressure of 748.7 psia for Unit 1 and 753.1 psia for Unit 2.

The process parameters are used by the manufacturer as the basis for redesign of the high pressure turbine to achieve the EPU electrical power generation.

Based on the heat balances, Table 2.5.5.1 lists the main steam conditions at the steam generator outlet and the reheat steam conditions to/from the moisture separator reheaters.

Table 2.5.5.1-1

	Current Operating Condition	EPU Operating Condition Unit 1	EPU Operating Condition Unit 2
Main Steam – Steam Generator Outlet			
Flow Rate, lbm/hr	6,666,136	8,111,808	8,112,096
Pressure, psia	811.7	802	806
Temperature, °F	519.9	518.6	519.1
Enthalpy (BTU/lb)	1199.0	1197.5	1197.4
Velocity (ft/sec)	124.4	148.9	148.1
Main Steam – Main Steam to HP Turbine			
Flow Rate, lbm/hr	6,111,500	7,539,997	7,537,281
Pressure, psia	774.9	748.7	753.1
Temperature, °F	514.6	510.7	511.4
Enthalpy (BTU/lb)	1199	1197.5	1197.4
Velocity (ft/sec)	185.6	235.7	234.7
Main Steam – Heating Steam to Moisture Separator Reheaters			
Flow Rate, lbm/hr	547,892	566,278	569,282
Pressure, psia	765.6	742.7	746.8
Temperature, °F	513.2	509.7	510.4
Enthalpy (BTU/lb)	1199	1197.5	1197.4
Velocity (ft/sec)	112.8	120.1	120.0

HP Turbine Exhaust			
Flow Rate. lbm/hr	5,535,724	6,664,610	6,663,816
Pressure (psia)	145.5	168.4	168.4
Enthalpy (BTU/lb)	1099.9	1100	1100
Velocity (ft/sec)	228.0	237.7	237.7
Reheat Steam – Moisture Separator Reheaters Inlet (Cross-Under)			
Flow Rate, lbm/hr	5,093,232	6,116,426	6,115,940
Pressure, psia	142.2	168.4	168.4
Temperature, °F	354.3	367.6	367.7
Enthalpy (BTU/lb)	1099.9	1100	1100
Velocity (ft/sec)	214.5	218.1	218.1
Reheat Steam – Moisture Separator Reheaters Outlet (Cross-Over)			
Flow Rate, lbm/hr	4,553,948	5,439,682	5,440,422
Pressure, psia	137.3	162.4	162.5
Temperature, °F	496.1	486.2	486.8
Enthalpy (BTU/lb)	1273.6	1265.7	1266
Velocity (ft/sec)	187.2	185.6	185.7
Main Steam Design Pressure / Temperature			
Pressure (psig)	1085	1085	1085
Temperature °F	555	555	555

Piping Evaluations

Design Pressure/Temperature

The main steam system design pressure/temperature of 1085 psig (1100 psia) and 555°F bound the maximum EPU operating conditions of approximately 806 psia and 520°F. The system design pressure also bounds the highest normal operating pressure, which occurs at no load conditions of 1020 psia. The no load conditions are not affected by the EPU. Therefore, the existing design conditions are unchanged by the EPU.

The reheat cross-under / cross-over piping was reviewed for EPU operating conditions. No changes are required for the reheat crossunder / crossover piping however, the piping is being re-rated. The crossunder piping design condition at EPU becomes 182 psig / 410°F and the crossover piping becomes 175 psig / 500°F. The review of the crossover and crossunder piping has determined that the piping and components are acceptable for the EPU conditions.

Flow Velocities

Flow velocities through the main steam piping from the steam generators to the turbine control and stop valves were calculated at current and EPU conditions. The flow velocities increased approximately 27% primarily due to the increased flow required by the EPU power level. As shown in Table 2.5.5.1-1, the highest velocity at EPU conditions is 14,262 fpm (237.7 ft/sec) which is below the industry design guideline of 20,000 fpm. EPU flow velocities in the main steam piping used for heating steam to the moisture separator reheaters increased approximately 23%. The highest velocity at EPU conditions is 7,206 fpm (120.1 ft/sec), which is significantly below the industry design guideline.

Flow velocities through the reheat steam piping to/from the moisture separator reheaters were calculated at current and EPU conditions. Flow velocities in the reheat piping essentially stayed the same since, although the EPU flow rates and temperatures are higher, the increase in EPU pressures is enough to offset these effects on the steam specific volume. The highest EPU velocity (13,791 fpm) is in the cross-under piping to the moisture separator reheaters. This velocity is essentially unchanged from the current condition and is well below the industry design guidelines.

Increases in fluid velocity affect the potential for flow accelerated corrosion (FAC). The FAC program already monitors these lines, particularly at previous erosion locations. The velocity in this piping at EPU conditions is only slightly higher than at current operating conditions, and at EPU conditions the moisture content is relatively unchanged (see Table 2.5.5.1-1). Therefore, the potential for erosion/corrosion is essentially unchanged by the EPU. Present monitoring activities will be continued after EPU implementation.

Vibration

The increase in steam flow velocity through piping and components has the potential to increase vibrations. Accordingly, during power ascension, piping will be monitored to identify line vibration anomalies. These vibration monitoring activities are discussed in LR Section 2.12, Power Ascension and Testing Plan.

Component Design Evaluations

Design Pressure/Temperature

As described above under Piping Evaluations, Design Pressure/Temperature, the main steam design pressure and temperature are not affected by the EPU. The design conditions of the main steam components, including isolation valves, relief valves, venturis, etc., were reviewed and, in all cases, determined to be greater than both the EPU operating conditions and the main steam design conditions of 1085 psig and 555°F.

The moisture separator reheaters shells have a design pressure and temperature of 175 psig/500°F which envelopes the maximum operating pressure and temperature. The moisture separator reheaters tubes contain main steam for heating and have a design pressure and temperature of 1100 psig/575°F which envelopes the main steam design conditions of 1085 psig/555°F.

Main Steam Safety Valves Capacities and Setpoints

The setpoints of the MSSVs are based on the design pressure of the steam generators (1085 psig). As a result of the EPU analysis for loss of load the existing setpoints are changing from 1085 psig, 1100 psig, 1125 psig and 1125 psig to EPU values of 1085 psig, 1100 psig, 1105 psig and 1105 psig. The Technical Specification changes for the MSSV setpoints are identified in LR Section 2.8.4.2, Overpressure Protection During Power Operation.

The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110% of the steam generator shell-side design pressure for the worst-case loss-of-heat sink event. Based on this requirement, the original plant design applied a conservative guideline that the valves should be sized to relieve 100% of the design steam flow to ensure that maximum system pressure did not exceed 110% of MSS design pressure.

PBNP has 8 safety valves with a total rated capacity of 7.12×10^6 lb/hr, which provides about 88% of the maximum EPU full-load steam flow.

LR Section 2.8.5, Accident and Transient Analyses, confirms that the installed safety valve capacity of 7.12×10^6 lb/hr is adequate for overpressure protection. Accordingly, the analysis demonstrates that the existing MSSVs (with the lift setpoint changes) are capable of maintaining the secondary side steam pressure below 110% of the steam generator shell design pressure.

The original design requirements for the MSSVs included a maximum flow limit per valve of 890,000 lb/hr at 1085 psig. Since the capacity of any single MSSV has not been changed as a result of EPU, the maximum capacity criteria remains satisfied at EPU conditions.

Atmospheric Dump Valves (ADVs)

The ADVs, which are located upstream of the main steam isolation valves (MSIVs) and adjacent to the MSSVs, are automatically controlled by steam line pressure during plant operation. The ADVs automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint to minimize safety valve lifting during steam pressure transients. As the steam line pressure decreases, the ADVs modulate closed and reseat at a pressure below the opening pressure. The ADV set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest set MSSV. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ADV setpoint.

The primary function of the ADVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the ADVs, in conjunction with the Auxiliary Feedwater System, permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point at which the Residual Heat Removal System (RHRS) can be placed in service. During cooldown, the ADVs are either automatically or manually controlled. In automatic control, each ADV proportional and integral (P&I) controller compares steamline pressure to the pressure setpoint, which is manually set by the plant operator.

In the event of a tube rupture event in conjunction with loss-of-offsite power (LOOP), the ADVs are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set MSSV. RCS cooldown and depressurization are required to preclude steam generator overfill and to terminate activity release to the atmosphere from the ruptured Steam Generator as discussed in LR Section 2.8.5.6.2, Steam Generator Tube Rupture.

In the event of a loss-of-offsite power, the capacity of the ADVs permits a plant cooldown to RHRS operating conditions (350°F) in about 10 hours (at a rate of about 25°F/hr), assuming cooldown starts 4 hours after reactor shutdown. This capacity requirement is limiting with respect to sizing the ADVs, and bounds the capacity required for tube rupture.

An evaluation of the installed combined capacity of both ADVs (1.78×10^6 lb/hr at 1100 psia) indicates that the required plant cooldown can still be achieved for the range of EPU NSSS design parameters LR Section 2.8.7.2, Natural Circulation Cooldown.

The performance of the ADVs is acceptable at EPU conditions to satisfy the decay heat removal requirements in accordance with PBNP current licensing basis requirements to remove residual heat (FSAR Section 7.2, Reactor Protection, Section 7.3, Engineered Safety Features Actuation System, Section 7.4, Other Actuation Systems, Section 7.6, Instrument Systems, Section 7.7, Control Systems and Section 9.3, Chemical and Volume Control System).

Main Steam Isolation and Non-Return Check Valves

The main steam isolation valves (MSIVs) are designed to close within 5 seconds after receipt of a closure signal. These valves must close for the purpose of main steam pipe break isolation, either inside or outside containment, and for containment isolation post accident.

The valves are designed for a differential pressure of 1200 psi, which is above the maximum system design pressure of 1085 psig and 110% steam generator overpressure allowed per the ASME code. As discussed above, although the EPU operating pressures are higher than current operating pressures at full power, the design pressure of 1085 psig remains unchanged by the EPU. Therefore, the valve design conditions remain unchanged by the EPU.

The main steam non-return check valves on each main steam header outside containment are simple check valves that have no operator. They are installed in the direction of flow and close on reverse flow to prevent steam from flowing back to the containment due to a steam line break inside containment.

The impact of the higher main steam flow rates through these valves during EPU operation was evaluated to confirm that the valves are not adversely affected in the open position during normal full power operation and that the valves will close within the required time period during accident conditions as discussed in LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports and LR Section 2.5.1.3, Pipe Failures.

The added pressure drop through the main steam isolation valves and non-return check valves at the normal EPU flow rates has been included in establishing the main steam supply pressure at the HP turbine inlet; thus ensuring adequate steam pressure for EPU full power generation.

The closure time of the main steam isolation valves is not affected by the EPU since the valve and operator design is based on the flow rate due to the worst case break flow that the valve experiences. The EPU does not affect the pipe break flows since the factors that affect maximum possible break flow, such as break size, location, steam generator pressure, and exit nozzle characteristics, etc., are not affected by EPU. The higher flow rates during normal EPU operation will actually cause the non-return check valves to close faster once the disc enters the flow stream during scenarios requiring containment isolation without a pipe break.

The higher flow rate during normal EPU operation through the main steam isolation valves and non-return check valves has the potential to cause vibration of the valve discs. The main steam isolation valves are installed in the reverse direction to flow and are provided with an operator which keeps its disc out of the flow stream. This design will minimize any added vibration caused by the higher EPU flow rate. Maintaining the disc out of the flow stream also minimizes any additional loads on the operator. However, the existing MSIV internals will be modified to improve reliability associated with of the valve closure at EPU conditions.

The main steam non-return check valve on each main steam header outside containment closes on reverse flow due to a main steam pipe break inside containment. These valves are not power operated. During normal operation the valve disk is out of the flow stream and hence does not affect by the EPU increase in steam velocity. While not originally scoped with the MSIV internal upgrades, the existing non-return check valve internals will be reviewed to determine if they also need to be modified to improve reliability associated with valve closure.

Moisture Separator Reheaters

The Moisture Separator Reheaters (MSRs) do not have relief valves. PBNP does not have any valves between the high pressure turbine exhaust, cross-under piping, MSR shell side, cross-over piping, low pressure turbine and the main condenser. The pressure in the shell side of the MSR is established by the losses between the HP turbine exhaust and the condenser pressure. The main condenser has rupture disks to limit internal pressure. As a result, the MSR shell side cannot be isolated and hence exposed to an overpressure scenario.

There is the potential for an MSR tube side leak or failure of the associated tube sheet. However, every pound of main steam that would leak into the MSR shell side would be a pound of steam that would not pass through the high pressure turbine. The net result would be a zero increase in flow to the MSR shell side. In addition main steam density is less than hot reheat density. The mix would have a smaller density and lower pipe velocity. The overall result would be a loss of efficiency, but no affect on SSCs. Thus, the MSRs are acceptable for operation at EPU conditions.

The mix of main steam's higher temperature and hot reheat steam would have the same type of effect. The mix would have a lower temperature. Again the result would be a loss of efficiency. The lower temperature would be bounded by the temperature of the hot reheat steam. Hence no affect on SSCs. Therefore, the MSRs are acceptable for operation at EPU conditions.

The MSRs were evaluated to determine the impact of the increased steam flow and pressure during EPU operation on tube vibration, thermal performance, moisture removal capability and erosion/corrosion effects.

The evaluation concluded:

- The reheater bundles will perform sufficiently to meet the thermal requirements of EPU operation at 100% power generation.

Based on analysis of similarly designed moisture separator reheaters at other plants and on a technical analysis of the impact of temperature, velocity and the moisture separator reheaters' physical characteristics, there are no erosion/corrosion concerns during EPU operation. PBNP will continue to inspect the MSR shells and nozzles as part of the erosion/corrosion program after implementation of the EPU to confirm the evaluation conclusions. See LR Section 2.1.8, Flow-Accelerated Corrosion.

Turbine Stop and Control Valves

The HP turbine stop valves have been evaluated as being adequate for EPU conditions. The HP turbine control valves are being modified to improve overall plant efficiency at EPU conditions. The ability of the turbine crossover steam dump system to provide overspeed protection at EPU conditions is discussed in LR Section 2.5.1.2.2, Turbine Generator.

Auxiliary Main Steam Supply Flow Rates

The auxiliary feedwater pump turbine steam supply and exhaust piping were determined to be acceptable for EPU conditions. The pressure ratings remain bounding. The required steam supply flow rate to the pump turbine is not affected by the EPU since the design brake horsepower (bhp) of the auxiliary feedwater pump turbine bounds the bhp required to supply the maximum EPU auxiliary feedwater flow rate. See LR Section 2.5.4.5, Auxiliary Feedwater.

The main steam system's ability to supply steam to auxiliary components, including the turbine gland seal steam supply and the condenser air ejectors, will not be affected by the EPU. None of these steam flow requirements change appreciably due to EPU conditions. The EPU heat balances include these required auxiliary flows and confirm that sufficient main steam flow exists to ensure the high pressure turbine and moisture separator reheaters' performance meets the desired EPU power generation requirements.

Main Steam Piping Drain Capacity

The main steam piping is provided with drains to collect water condensing in the piping. The purpose of the drains is to prevent turbine water induction. The drains were originally designed with sufficient capacity based on start-up conditions where hot steam is introduced into cold piping and operating conditions where heat is transferred through the pipe walls. Since startup steam conditions, e.g., flow, quality, temperature and pressure, remain unchanged by the EPU, there is no increase in startup drain flow. Operating conditions based on heat losses through the pipe wall are based on the difference between the internal pipe wall temperature and the external temperature. Pipe velocity (the only parameter that is changing as a result of EPU) does not affect heat transfer because the pipe assumed to be the temperature of the fluid. Internal pipe temperature is reduced as a result of EPU from 519.9°F to 519.1°F: hence the steam line drains are acceptable for EPU conditions.

Other Considerations

Engineered Safety Features and associated systems are protected from loss of function due to dynamic effects and missiles which might result from a loss of coolant accident. Protection is provided by missile shielding and/or segregation of redundant components. This is discussed in detail in FSAR Section 6.0, Engineered Safety Features. Refer to LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects. The final design of SSC's remain acceptable to protect safety related SSC's from the effects of pipe whip and jet impingement loading for EPU. Missile Protection Criteria is discussed is FSAR Section 4.1, Reactor Coolant System, Design Basis, Section 5.1, Containment System Structure, Section 5.1.2.7, Missile

Protection, and Section 6.1, Engineered Safety Features Criteria. Refer to LR Section 2.5.1.2.1, Internally Generated Missiles. The existing missile protection measures inside containment remain effective for EPU conditions.

PBNP is a dual unit installation. FSAR identifies that the shared systems or components are identified in FSAR Section 6.2. Per FSAR Section 6.2 the Main Steam System is not a shared system. (PNBP GDC 4)

2.5.5.1.3 Conclusions

PBNP has assessed the effects of the proposed EPU on the main steam supply system and concludes that the assessment adequately accounts for the effects of changes in plant conditions on the design of the main steam supply system. PBNP concludes that the main steam supply system will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. PBNP further concludes that the main steam supply system will continue to meet the requirements of PBNP GDCs 4, 6, and 40. Therefore, PBNP finds the proposed EPU is acceptable with respect to the main steam supply system.

2.5.5.2 Main Condenser

2.5.5.2.1 Regulatory Evaluation

The main condenser (MC) system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). The PBNP review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the Turbine Bypass System (TBS).

The NRC's acceptance criteria for the MC system are based on:

- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 10.4.1.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 60 is as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

The PBNP main condenser system is discussed in FSAR Section 10.1, Steam and Power Conversion System.

The condenser air ejector exhaust is monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation is indicated and alarmed in the Control Room.

Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), has been formalized in the Technical Specification (TS) 5.5.4, Radioactive Effluent Controls Program and TS 5.5.1, Offsite Dose Calculation Manual.

In addition to the evaluations described in the FSAR, PBNP systems were evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, the main condenser is not within the scope of License Renewal. However, the programs used to manage the aging effects associated with steam and power conversion systems are discussed in Section 3.4 of the PBNP License Renewal Application.

2.5.5.2.2 Technical Evaluation

Introduction

The main condenser is discussed in the FSAR Section 10.1, Steam and Power Conversion System. The main condenser is a two-section, single pass, deaerating type surface condenser of the radial flow type with semi-cylindrical water boxes bolted at both ends. The condenser extracts the latent heat of vaporization from the low pressure turbine exhaust steam, the steam dump system (when in operation) and miscellaneous flows, drains and vents during normal plant operation. This heat is transferred to the circulating water system. The resulting condensate is collected in the condenser hotwell before entering the condensate and feedwater system. The condensate hotwell level control system maintains sufficient level to provide the suction head for the condensate pumps. The condenser deaerates the condensate before it leaves the condenser hotwell.

The condenser uses circulating water for heat removal and transfer of the rejected heat to Lake Michigan. The circulating water system is described in FSAR Section 10.1, Steam and Power Conversion System. The evaluation of the EPU effect on the circulating water system is described in LR Section 2.5.8.1, Circulating Water System.

The steam dump system is discussed in the FSAR Section 10.1, Steam and Power Conversion System. The purpose of the steam dump system is to minimize the stresses on the nuclear steam supply system induced by changes in the secondary plant steam demand. The turbine bypass steam discharges through the steam dump valves into the main steam dump lines and goes directly to the main condenser. As discussed in LR Section 2.5.5.3, Turbine Bypass, the steam dump capacity is not being increased with EPU. Rather, that section demonstrates that the existing steam dump system remains adequate for EPU. Consequently, there is no EPU impact to the condenser as a result of the steam dump system. Refere to Reference 2.5.5.3, Turbine Bypass, for aditional duscussion of the steam dump system.

During plant operation, non-condensable gases from the main condenser are exhausted through the Condenser Evacuation System (LR Section 2.5.3.2, Main Condenser Evacuation System) and processed for release in the Gaseous Waste Management System (LR Section 2.5.6.1, Gaseous Waste Management). The adequacy of the PBNP main condenser system design relative to control of the release of radioactive material from steam in the turbine to the environment is provided by demonstration of the adequacy of the main condenser to maintain structural capability during operation (this LR section), the condenser evacuation system to maintain the condenser at vacuum conditions (LR Section 2.5.3.2, Main Condenser Evacuation

System) and the Gaseous Waste Management System (LR Section 2.5.6.1), to process, control and monitor the effluent for release to the environment.

Description of Analyses and Evaluations

The main condenser will experience higher steam flows due to the increase in LP turbine exhaust flow at the EPU power level and higher steam flows due to the increase in the steam flow bypassed to the condenser by the steam dump system following a load rejection at EPU. The evaluation determined the impact of the EPU conditions on condenser performance and integrity as follows:

- Determine the increased condenser duty and confirm the condenser's ability to reject heat to the circulating water system and maintain a low enough condenser backpressure for the turbine to meet its EPU MW output and performance requirements.
- Evaluate the condenser hotwell storage capacity to provide sufficient storage volume with the maximum flow rate at EPU conditions.
- Evaluate the capability of the main condenser to remove dissolved gases and air in-leakage from the condensate.
- Evaluate the steam blowdown effects of increased steam flow at normal EPU power operation and during steam dump to the condenser following load rejection on condenser tube vibration.
- Evaluate the impact of the increased steam dump flow on condenser backpressure during steam dump conditions and confirm that none of the automatic plant protection setpoints, such as turbine trip, are initiated.
- Evaluate the impact of the increased steam flow on the condenser spargers, baffles, and impingement plates, provided to protect the condenser tube and internal components from damage due to incoming steam and water flows.
- Evaluate the impact of the increased steam flow on the plant design to control the release of radioactive effluents.

Results

The evaluation determined that the condenser satisfactorily removes the increased EPU heat loads, condenses the required steam flows and maintains an acceptable vacuum using circulating water at the current normal operating flow rate. Table 2.5.5.2-1 describes the key design parameters of the main condenser and compares its performance at current operating and EPU conditions.

At EPU conditions, the hotwell will maintain approximately 3.65 minutes of storage and surge capacity which is more than the volume recommended by the HEI Standard for Steam Surface Condensers (i.e., one minute of condensate reserve at full power operation). Therefore, the existing hotwell capacity is acceptable for EPU conditions. The PBNP installation is acceptable at EPU conditions.

The condensate pump discharge oxygen level at EPU conditions rises from 3-4.5 ppb to 3.5-5.2 ppb, but remains below the original design value for the condenser of 10.0 ppb. The ability of the condenser to maintain the required deaeration of condensate flow remains acceptable at EPU conditions. Only the non-condensables, not the air in-leakage, collected in the condenser will increase at EPU conditions. For a further discussion of condenser deaeration refer to LR Section 2.5.3.2, Main Condenser Evacuation System.

The evaluation also confirmed that the condenser adequately withstands the steam blowdown effects of a steam dump following a load rejection. A main condenser tube vibration evaluation determined that the overall condenser tube support configuration is adequate with the exception of the lower tube bundle areas where there are no steam dump baffles. Additional tube support at the lower tube bundle areas where there are no steam dump baffles will be installed for EPU operation.

The current turbine trip set points for condenser backpressure are not affected by the increased steam flow rates at EPU conditions for normal operation and steam dump following a load rejection. The highest normal backpressure at EPU full power operation is 3.34 inches HgA with a circulating water temperature of 75°F.

Per LR Section 2.5.5.3, Turbine Bypass, a 50% load rejection is the worst case analysis considered for precluding a unit trip from full power. Following a 50% load rejection, the condenser backpressure is 3.78 inches HgA. This is lower than the condenser low vacuum alarm of 25 inches Hg Vac (4.27 inches HgA). It is well below the turbine trip set point range of 7.27-9.27 inches HgA. Based on this, the PBNP units can accommodate a 50% load reduction without a turbine trip.

The design of the main condenser does not change following the implementation of the EPU. Therefore, the EPU does not impact the ability of the PBNP regarding the control of radioactive material in accordance with PBNP GDC 70. Monitoring of the air and non-condensables leaving the condenser is accomplished by a radiation monitor in the condenser evacuation system, described in LR Section 2.5.3.2, Main Condenser Evacuation System. The impact of EPU on radiological effluent releases from PBNP, radiation monitoring setpoints and compliance with 10 CFR 50, Appendix I, is discussed in LR Section 2.10.1, Occupational and Public Radiation Doses.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal

The main condenser is not within the scope of license renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries for the main condenser. Operating the main condenser at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.5.2.3 Conclusion

PBNP has assessed the effects of the proposed EPU on the main condenser system and concludes that it has adequately accounted for the effects of the changes in plant conditions on the design of the main condenser system. PNBP concludes that the main condenser system will continue to maintain its ability to withstand the blowdown effects of steam from the turbine bypass system and thereby continue to meet PBNP GDC 70 for prevention of the radiological consequences of failures in the system. Therefore, PBNP finds the proposed EPU acceptable with respect to the main condenser system.

Table 2.5.5.2-1 Main Condenser Performance Characteristics

	Current Operating Values 100% Power	EPU Operating Values 100% Power
Condenser Duty	3.419×10^9 Btu/hr	4.03×10^9 Btu/hr
CW Temperature Rise (CWIT at 42.6°F)	20.7°F	24.4°F
CW Temperature Rise (CWIT at 75°F)	Not Available	24.9°F
Condenser Backpressure (CWIT at 42.6°F) (Condenser 1 has higher pressure than Condenser 2)	1.20 inch HgA	1.53 inch HgA
Condenser Backpressure (CWIT at 75°F)	Not Available	3.34 inch HgA
Circulating Water Intake Temperature = CWIT		

2.5.5.3 Turbine Bypass

2.5.5.3.1 Regulatory Evaluation

The turbine bypass system, which at PBNP is referred to as the condenser steam dump system, is designed to discharge a portion of main steam flow directly to the main condenser system, bypassing the turbine. This steam bypass enables the plant to take step-load reductions up to the condenser steam dump system capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control steam generator pressure. The PBNP review focused on the effects that EPU has on load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent condenser steam dump system operation.

The NRC's acceptance criteria for the condenser steam dump system are based on:

- GDC 4, insofar as it requires that structures, systems, and components important-to-safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures
- 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 at a rate such that Specified Acceptable Fuel Design Limits (SAFDL) and the design conditions of the reactor coolant pressure boundary are not exceeded

Specific review criteria are contained in SRP Section 10.4.4.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4 and 34 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

CRITERION: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (PBNP GDC 6)

The condenser steam dump system is non-safety related and is not credited in any design basis accident.

As noted in the FSAR Section 3.1.2.1, Reactor, Principal Design Criteria, and Section 4.1, Reactor Coolant System, Design Basis, a loss of external electrical load of 50% of full power or less is normally controlled by rod cluster insertion together with a controlled steam dump to the condenser to prevent a large temperature and pressure increase in the reactor coolant system and thus prevent a reactor trip. The condenser steam dump system also makes it possible to accept a turbine trip from below 50% power without a reactor trip.

The condenser steam dump system was evaluated for postulated system piping failures in FSAR Appendix A.2, High Energy Pipe Failure Outside Containment.

Inadvertent condenser steam dump system operation is addressed in FSAR Section 7.1.2, General Design Criteria, for Reactivity Shutdown Capability.

The condenser steam dump system is also discussed in FSAR Section 10.1, Steam and Power Conversion System.

In addition to the evaluations described in the PBNP FSAR, the main steam system, which includes the condenser steam dump system, was evaluated as part of the plant license renewal. System and component materials of construction, operating history and the plant programs used to manage aging effects are documented in:

- License Renewal Safety Evaluation Report for the Point Beach Nuclear Plant Units 1 and 2, (NUREG-1839), dated December 2005

Condenser steam dump piping and components are not within the scope of license renewal. With respect to the above SER, the main steam system is described in Section 2.3.4.1, Main and Auxiliary Steam System. The programs used to manage the aging effects in main steam are discussed in Section 3.4, Aging Management of Steam and Power Conversion Systems.

2.5.5.3.2 Technical Evaluation

Introduction

The condenser steam dump system is described in the FSAR Section 10.1, Steam and Power Conversion. The condenser steam dump system consists of eight condenser dump valves and piping from the main steam headers to the condenser. The purpose of the condenser steam dump system is to minimize the stresses on the nuclear steam supply system induced by changes in the secondary plant steam demand. The condenser steam dump valves are designed to pass 40% of main steam flow at current 100% power operation and at full-load steam pressure. In conjunction with the rod control system, which accommodates 10% of the load reduction, the condenser steam dump system permits the NSSS to withstand an external load reduction of up to 50% of plant rated electrical load without a reactor/turbine trip. In addition to limiting the reactor coolant system temperature and pressure transients following reductions in steam loads, the condenser steam dump system also serves to minimize the undesirable possibility of lifting the pressurizer and main steam safety valves and aids in conducting reactor coolant system cooldowns and heatups. There is a control system interlock which prevents initiation of condenser steam dump when the condenser (loss of vacuum) vacuum is above a preset value.

Description of Analyses and Evaluations

The components in the condenser steam dump system were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations addressed the following:

- Component design parameters versus the EPU operating conditions.
- Piping velocities versus industry standard guidelines.

Dynamic effects, including the effects of missiles, pipe whipping, and discharging are addressed in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures.

Response to design basis loading and unloading transients are discussed in LR Section 2.4.2, Plant Operability (Margin to Trip).

The condenser steam dump system was also evaluated to ensure that the system was capable of performing its intended function for the range of NSSS design parameters approved for EPU. The evaluation was performed at 100% EPU power for the analyzed NSSS thermal power of 1806 MWt.

The condenser steam dump system creates an artificial steam load by dumping steam from ahead of the turbine valves to the main condenser. The Westinghouse original sizing criterion conservatively recommends that the condenser steam dump system (valves and pipe) be capable of discharging 40% of the rated steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 50% of plant-rated electrical load without a reactor/turbine trip. To prevent a trip, this transient requires all NSSS control systems to be in automatic, including the rod control system, which accommodates 10% of the load reduction. The condenser steam dump system prevents MSSV lifting following a reactor trip from full power.

PBNP is equipped with 8 condenser steam dump valves and each valve is specified to have a flow capacity of 265,312 lbm/hr at a valve inlet pressure of 736.7 psia.

The capacity of the condenser steam dump system (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. Accordingly, NSSS operation within the proposed range of design parameters for EPU will result in a reduced steam dump capability relative to the original Westinghouse sizing criteria. An evaluation indicates steam dump capacity could be as low as 18.7% of rated steam flow (8.08×10^6 lb/hr), or 1.510×10^6 lb/hr at a full-load steam pressure equal to 601 psia. At full-load steam pressures higher than 601 psia (T_{avg} = 558.0°F), steam dump capacity would increase. For example, at a full-load steam pressures of 755 psia (T_{avg} = 577°F), steam dump capacity would be 26.9% of rated flow (7.39×10^6 lb/hr), or 1.988×10^6 lb/hr.

As described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, no adjustments are required to the steam dump control system for EPU rated flow to ensure the plant will continue to satisfactorily respond to design basis loading and unloading transients described in LR Section 2.4.2, Plant Operability.

The NSSS stability and operability analysis described in LR Section 2.4.2, Plant Operability (Margin to Trip), provides an evaluation of the adequacy of the condenser steam dump system in conjunction with the changes to the control system set points at EPU conditions. This section states that a 50% load rejection with steam dumps available to the condenser can be accommodated without resulting in either a reactor/turbine trip or steam generator safety valve actuation. The analysis results indicate that for the range of NSSS design parameters approved for EPU, a rapid ramp load decrease equivalent to 50% of the EPU rated thermal power at a maximum turbine unloading rate of 200% per minute can be accommodated with no plant hardware changes. At less than 50% of the EPU rated thermal power, a turbine trip can be accommodated without a reactor trip occurring.

Based on these analyses, the condenser steam dumps meet requirements at EPU conditions as discussed above.

The condenser steam dump valves have NSSS requirements on time for opening and for modulating steam flow. To provide effective control of flow on large step-load reductions or plant trip, the steam dump valves are required to go from full-closed to full-open in 3 seconds at any pressure between 50 psi less than full-load pressure and steam generator design pressure. The dump valves are also required to modulate to control flow. For modulating steam dump flow, the positioning response may be slower with an allowed maximum full-stroke time of 20 seconds. These time response requirements are not affected by the EPU and must still be met.

The original design requirements for the steam dump valves, as well as the SG Atmospheric Dump Valves (ADVs) and main steam safety valves (MSSVs) included a maximum flow limit per valve of 890,000 lb/hr at 1085 psig. The capacity of any single MSSV, ADV, or condenser steam dump valve is acceptable for EPU. LR Section 2.8.5.1.1, Reduction In Feedwater Enthalpy, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve, demonstrates that the results of a stuck-open steam generator relief valve or a safety valve are bounded by the large (hypothetical) steam line break results. Therefore it can be concluded that a stuck-open steam dump valve is also bounded by the large steam line break.

The performance of the condenser steam dump system is acceptable at EPU conditions with no plant changes in accordance with PBNP current licensing basis requirements.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Condenser steam dump piping and components are not within the scope of License Renewal. With respect to the License Renewal SER (NUREG-1839), the condenser steam dump system is not discussed; however, it is part of the main steam system which is described in Section 2.3.4.1, Main and Auxiliary Steam System. The programs used to manage the aging effects in main steam are discussed in Section 3.4.2.3.2, Main and Auxiliary Steam System.

Although the condenser steam dump system is not within the scope of License Renewal, portions of the main steam system are within the scope. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the condenser steam dump system at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Results

The condenser steam dump system piping design pressure of 1085 psig (1100 psia) bounds the EPU operating conditions of approximately 800 psia and also bounds the highest operating pressure which occurs at no load conditions of 1020 psia. The no load conditions are not affected by the EPU.

The condenser steam dump system performance is acceptable at EPU conditions with no plant changes. Since no plant changes are required there are no changes in the probability of the condenser steam dump system causing missiles nor is there any requirement of changing the means of preventing the effects of dynamic events or missiles from damaging the system. The results of the EPU condenser steam dump system performance evaluation coupled with other EPU analysis results can be summarized as follows:

NSSS operation within the proposed range of design parameters for EPU will result in a reduced steam dump capability relative to the original Westinghouse sizing criteria. However, the NSSS stability and operability analysis discussed in LR Section 2.4.2, Plant Operability (Margin to Trip) concludes that the reduced capacity is adequate to achieve 50% load rejection (that is, no reactor/turbine trip) for the range of NSSS design parameters approved for EPU.

The steam dump capacity at EPU conditions is adequate to prevent MSSV lifting following reactor trip from full power.

The actual capacity of any single steam dump valve at EPU conditions is not impacted by EPU. Accordingly, as documented in LR Section 2.8.5.1.1, Reduction In Feedwater Enthalpy, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve, an inadvertent opening of a condenser steam dump valve is acceptable at EPU conditions with no plant changes. The performance of the condenser steam dump system is acceptable at EPU conditions with no plant changes in accordance with PBNP current licensing basis requirements with respect to the requirement that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded.

2.5.5.3.3 Conclusion

PBNP has reviewed the assessment of the effects of the proposed EPU on the condenser steam dump system. PBNP concludes that the assessment has adequately accounted for the effects of changes in plant conditions on the design of the system. PBNP concludes that the condenser steam dump system will continue to provide a means for shutting down the plant during normal operations and maintains the 50% load rejection capacity at EPU conditions. PBNP further concludes that condenser steam dump system failures will not adversely affect essential systems or components. Based on this, PBNP concludes that the condenser steam dump system will continue to meet PBNP GDCs 6 and 40. Therefore, PBNP finds the proposed EPU acceptable with respect to the condenser steam dump system.

2.5.5.4 Condensate and Feedwater

2.5.5.4.1 Regulatory Evaluation

The condensate and feedwater system provides feedwater at the appropriate temperature, pressure, and flow rate to the steam generators. The only part of the condensate and feedwater system classified as safety-related is the feedwater piping from the steam generators up to and including the outermost containment isolation valve. The PBNP review focused on the effects of the proposed EPU on previous analyses and considerations with respect to the capability of the condensate and feedwater system to supply adequate feedwater during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. The PBNP review also considered the effects of the proposed EPU on the feedwater system, including the auxiliary feedwater system (AFW) piping entering the steam generator, with regard to possible fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions.

The NRC's acceptance criteria for the condensate and feedwater system are based on:

- GDC 4, insofar as it requires that Structures Systems, and Components (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;
- 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 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 that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure.

Specific review criteria are contained in Standard Review Plan (SRP) Section 10.4.7.

PBNP Current Licensing Basis

The principal heat removal systems which are interconnected with the Reactor Coolant System are the steam and feedwater systems and the safety injection and residual heat removal systems. The Reactor Coolant System is dependent upon the steam generators and the steam, feedwater, and condensate systems for decay heat removal.

The Main Feedwater Regulating Valves (MFRVs) and MFRV bypass valves provide isolation of main feedwater (MFW) flow to the secondary side of the steam generators following a Steam Line Break (SLB). As described in FSAR Section 14.2.5, Rupture of a Steam Pipe, termination of feedwater addition to the affected steam generator limits the mass and energy release for SLBs and reduces the cooldown effects for SLBs.

Redundant isolation of the main feedwater lines is provided. Following a SLB, sustained high feedwater flow would cause additional cooldown, thus, in addition to the normal control action which will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater pump discharge valves. Additional isolation is provided by tripping the condensate and heater drain tank pumps on a high containment pressure safety injection signal to help prevent over-pressurization of the containment for ruptures inside containment.

The Containment Pressure Condensate Isolation (CPCI) circuit trips the two condensate pumps and the three heater drain tank pumps upon sensing a high pressure in containment. The circuit trips the pumps on high containment pressure (2/3 logic). The purpose of this circuit is to prevent overpressurization of containment assuming one of the main feedwater regulating valves fails to close during a steamline break inside containment.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC 4, 5 and 44 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

PBNP's specific GDC for the containment isolation function of the condensate and feedwater systems are as follows:

CRITERION: Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus. (PBNP GDC 53)

As described in FSAR Section 5.2, Containment Isolation System, the feedwater line is considered a Class 4 penetration. A Class 4 penetration is defined as a normally operating incoming line which penetrates the containment, is connected to a closed system inside containment, is protected from the dynamic effects of high energy line breaks throughout its length, and is provided with at least one manual isolation valve outside containment.

CRITERION: Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits. (PBNP GDC 57)

Capability is provided to the extent practical for testing the functional operability of containment isolation valves.

The condensate and feedwater systems are further discussed in FSAR Section 10.0, Steam and Power Conversion and Section 10.1, Steam and Power Conversion System.

In addition to the evaluations described in the FSAR, PBNP's condensate and feedwater system was evaluated for plant License Renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

With respect to the above SER, feedwater and condensate is described in Section 2.3.4.2, Feedwater and Condensate Systems. Aging effects, and the programs used to manage the aging effects associated with feedwater and condensate, are discussed in Section 3.4, Aging Management of Steam and Power Conversion System.

2.5.5.4.2 Technical Evaluation

Introduction

The condensate and feedwater system (CS) is designed to transport condensed steam from the condenser to the steam generators at the most efficient temperature and pressure. The system consists of two 50% condensate pumps, three 50% heater drain pumps, and two 50% steam generator feedwater pumps. In addition the system consists of a gland steam condenser, condensate cooler, steam jet air ejector, hydrogen coolers, two strings of four low pressure feedwater heaters, two strings of a single high pressure heater, main feedwater regulator valves, and heater drain pump level control valves. EPU affects all the feedwater heaters, the condensate pumps, steam generator feedwater pumps, which will be replaced, and the feedwater regulator valves, which will be modified prior to implementing EPU.

The condensate and feedwater system (CS) provides feedwater at the appropriate temperature, pressure, and flow rate to the steam generators. The only part of the CS classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valve.

New Main Feedwater Isolation Valves (MFIVs) are being added between the existing Feedwater Regulating Valves and the containment to limit the mass of water injected into the Steam Generators after feedwater system isolation. This is required to mitigate the effects of a MSLB inside containment for EPU. Refer to LR Section 2.6.1, Primary Containment Functional Design, for additional discussion of MSLB and Containment Response.

The feedwater regulating valves are being modified prior to EPU by installing a new trim kit to provide the required Cv for the increased FW flow due to EPU. The feedwater regulating valves provide a means of monitoring availability of main feedwater by means of valve position and provide a backup to the new MFIVs.

Safety related components and piping within the feedwater system are used for containment isolation and feedwater isolation during accidents and transients, as well as being the main feedwater flow paths to each steam generator during normal operation. The safety related portion of the piping is also used for auxiliary feedwater addition.

Specific condensate and feedwater system design functions include:

- The condensate and feedwater system is designed to supply approximately 8.11×10^6 lb/hr to the steam generators at EPU conditions during steady state operation at maximum guaranteed turbine load.
- The condensate system can supply 95% of full load feedwater flow to the main feedwater pumps during 50% load drop transients.
- The feedwater portion of the system is designed to supply the feedwater required for various loads at steady state operation and to maintain this flow, as required, during the steam dump condition following a large load reduction.
- The system is designed to maintain uniform feedwater flow to both steam generators under all conditions and to maintain proper steam generator water levels automatically during steady state and transient conditions.

Description of Analyses and Evaluations

The condensate and feedwater system and components were evaluated to assure that they are capable of performing their intended functions at power uprate conditions. The evaluation considered the effects of the power uprate on the following system and component design aspects:

- Design pressure and temperature on piping and valves and components versus power uprate operating pressure and temperatures
- Flow velocities
- 50% load rejection capability
- Feedwater isolation valves closure within the required time period at power uprate hydraulic conditions of flow and pressure drop
- Capacity and control capability of the feedwater regulating valves
- Feedwater heater design parameters and operating characteristics
- Pump and pump supporting subsystems design capabilities, including net positive suction head (NPSH), flow, head, break horsepower, minimum flow protection, and seal water supplies
- Process set points for pump protection, such as pump NPSH

The condensate and feedwater system was evaluated by using a hydraulic model of the system components, piping, and the power uprate heat balance. Physical plant data for the installed components and piping were used in the hydraulic model. Physical changes to condensate and feedwater components, valves and piping that resulted from the power uprate evaluations were incorporated into the hydraulic model and verified as acceptable.

Current plant operating data were gathered and included in the heat balance and hydraulic model to reflect the present day performance of the existing components.

The power uprate heat balances were used to establish the flow, temperature and heat transfer requirements at the power uprate power level.

Other evaluations of condensate and feedwater system and components are addressed in the following LR sections:

- Effects of increased flow and velocity on erosion and corrosion – LR Section 2.1.8, Flow-Accelerated Corrosion
- Piping component and supports – LR Section 2.2.2.2, Balance of Plant Piping, Components, and Supports
- Protection against dynamic effects, including requirements of missiles, pipe whip and discharging fluids – LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, and LR Section 2.5.1.3, Pipe Failures
- Operation of the condensate and feedwater system, including isolation features during postulated abnormal and accident scenarios, is discussed in LR Section 2.4.2, Plant Operability (Margin to Trip)
- Feedwater isolation valve testing and valve closure, is discussed in LR Section 2.2.4, Safety-Related Valves and Pumps

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the condensate and feedwater system are within the scope of the License Renewal. EPU activities include component replacement and modifications to meet the EPU conditions. These changes do not introduce any new functions or change of functions of existing components that would affect the license renewal system evaluation boundaries. Operating the condensate and feedwater system at EPU conditions does not add any new types of materials (although some equipment is being replaced with similar equipment) or previously unevaluated materials to the system. Thus, no new aging effects requiring management are identified. Aging effects, and the programs used to manage the aging effects for the new FIVs will be addressed in the plant modification process.

Results

The following subsections evaluate the specific condensate and feedwater system capabilities while operating at EPU conditions.

Design Criteria

The evaluation of the condensate and feedwater systems capabilities at EPU conditions demonstrates that the PBNP will continue to meet the current licensing basis for piping failures as described in LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures Failures.

Although PBNP is a dual unit installation, the condensate and feedwater systems are not shared between the units. PBNP will continue to meet the current licensing basis with respect to requirements to maintain condensate and feedwater SSCs important to safety not be shared among nuclear power units.

The evaluation of the condensate and feedwater systems capabilities at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis with respect to the requirement that the system be capable to transfer heat loads from safety related SSCs to a heat sink under both normal operating and accident conditions, and that suitable isolation be provided to ensure that the system safety function can be accomplished assuming a single failure. The condensate and feedwater system provides this capability during accident conditions and is capable of achieving this function considering a single failure, with the addition of enhanced feedwater isolation capability discussed below. The implementation of EPU does not affect the capability of this system to perform these functions as demonstrated by the system and component evaluation results described below and by the results of the analyses of postulated abnormal and accident scenarios discussed in LR Section 2.8.5, Accident and Transient Analyses and LR Section 2.6.1, Primary Containment Functional Design.

System Operating Conditions – Current versus EPU Conditions

The condensate and feedwater system operating conditions; flow, temperature and pressure, were determined from hydraulic modeling of the piping systems and from the current operating (benchmark) and EPU heat balances. Table 2.5.5.4-1, Condensate and Feedwater System Operating Conditions, compares the current condensate and feedwater system conditions to the EPU conditions.

Design Pressures and Temperatures – Components and Piping

The design pressures and temperatures of condensate and feedwater components and piping bound the EPU operating conditions.

Feedwater Heaters

Feedwater heaters 1A/B through 5A/B were evaluated for EPU conditions. All were determined to be unacceptable based on their design, materials, construction, and performance. They are being replaced with new feedwater heaters sized and constructed for EPU conditions. In general, the standards contained in Heat Exchange Institute (HEI) Standards for Feedwater Heaters were used for acceptance criteria.

The replacement feedwater heaters will meet the thermal performance requirements of the EPU conditions and specified to have greater reliability. Current plant operating data bench marked the current operating heat balance. This current operating heat balance was then adjusted to predict the plant performance at EPU conditions. These EPU heat balances show the expected EPU power generation which was used to purchase the new feedwater heaters.

The design of the new (replacement) feedwater heater provides:

- Heater tube velocities that are acceptable at EPU conditions per HEI
- Heater tube side pressure drops that are acceptable at EPU condition as calculated in the condensate and feedwater hydraulic model
- Heater shell design pressure that are acceptable for EPU conditions per industrial standards
- Heater shell and tube side relief valves that have set points and capacities that are acceptable for EPU conditions, including heater string bypass operation
- Heater shell side vents that are acceptable for EPU conditions

* Materials resistant to erosion/corrosion

Flow Velocities - Piping

Flow velocities through the condensate and feedwater system were calculated at current and EPU conditions. Generally, the flow velocities increased approximately 25% primarily due to the increased flow required by the EPU power level. Velocities generally remain below the industry standard guidelines for these services; although there are some pipes whose velocities exceed the guidelines. These individual pipes are evaluated as part of the flow accelerated corrosion program as described in LR Section 2.1.8, Flow-Accelerated Corrosion.

Feedwater Regulating Valves

The existing feedwater regulating valves (FRVs) are being modified with higher rated Cv trim and new actuators that provide the required flow at the required pressure drop at EPU conditions. The replacement valves allow the valve to remain less than 80% open at EPU normal plant operation so as to provide sufficient control over a range of operating conditions.

The sizing and control capability of the feedwater regulating valves, together with the hydraulic operation of the replacement condensate pumps and feedwater pumps, provides sufficient flexibility to accommodate plant load rejection transients by providing 95% of rated flow with a 100 psi increase in steam generator pressure. EPU is not changing the function of, or the monitoring features of the feedwater regulating valves.

Condensate and Feedwater Pumps and Supporting Subsystems

The condensate and feedwater pumps and their supporting subsystems require replacement to operate to meet the requirements of EPU conditions.

The existing condensate pumps have insufficient flow and head, and cannot supply sufficient NPSH to the steam generator feedwater pumps. The replacement pumps have a higher operating point that is adequate to supply EPU required flow and head and maintain sufficient NPSH to the steam generator feedwater pump. The new pump has a flatter curve that increased the operating flow and head on the pump curve, but maintains the existing shut-off head. Thus the operating condition is increased to the EPU conditions, while the design conditions (other than flow) remain unchanged. The existing motors are also inadequate to provide sufficient motive force for pump operation at EPU conditions. New motors for EPU conditions are being provided. The new condensate pump motors will be 4000V with a horsepower rating of 1500 and a service factor of 1.15.

The existing condensate pump recirculation system provides sufficient flow for condensate pump protection and supplies the minimum flow required by the gland steam condenser, steam jet air ejectors, condensate cooler, and hydrogen coolers.

The existing feedwater pumps are also inadequate for flow and head at EPU conditions. In addition the NPSH required of the existing pump is high. Replacement pumps will be installed with higher operating heads and flows, and lower required NPSH that meet EPU conditions. This pump, like the condensate pump has a flatter curve that provides a higher head-flow operating point while maintaining the same shut-off head point. Thus the operating condition is increased to the EPU conditions, while the design conditions (other than flow) remain unchanged. The existing motors are also inadequate to provide sufficient motive force for pump operation at EPU conditions. New motors for EPU conditions are being provided. The new feedwater pump motors will be 4000V with a horsepower rating of 6200 and a service factor of 1.15

The present design of the feedwater pump minimum flow system is inadequate for the replacement pumps. New minimum flow control valves and piping systems will be provided to meet the new feedwater pumps minimum flow requirements.

The existing low pressure feedwater heater bypass line will operate adequately at EPU conditions to provide sufficient flow and pressure at the feedwater pump suctions. The pressure actuation and reset set points for bypass line operation are being changed to match the EPU hydraulic conditions.

The NPSH margin setpoint, which is calculated from the measured pressure and temperature at the feedwater pump suction, is also being changed to match the EPU operating conditions and the NPSH requirements of the new pump.

The existing seal water subsystem for the feedwater pumps is being changed to provide sufficient seal water flow and pressure from the condensate pumps. The changes have minimal affect on the seal water subsystem.

The existing heater drain pumps and motors are sufficiently sized to meet EPU operating conditions. However, the drain level control valve is too small to pass the EPU expected flows. Per the condensate and feedwater system hydraulic model, the heater drain level control valve is being replaced with one with a larger Cv to meet EPU required flows.

50% Load Rejection Capability

The plant is designed to prevent a reactor trip following a large step load reduction of 50% or less by automatically opening the steam dump valves to the condenser. During the load rejection, a complete loss of heater drain flow is assumed, and the steam generator pressure is increased 100 psi greater than the 100% power case. The low pressure feedwater heater bypass opens to reduce condensate system pressure drop resulting in an increase in feedwater pump NPSHa. The analysis has both condensate pumps operating; two low pressure strings open and its bypass open, no heater drain tank flow, and both feedwater pumps operating. In addition, the regulator valves go 100% open. Under this scenario, the steam generator is supplied with 95% of full load maximum flow at 100 psi greater than the 100% power case, as noted above. This design feature will prevent a unit trip at EPU conditions.

Feedwater Isolation Valves

In order to mitigate a design basis steam line break in containment at EPU conditions, faster isolation of feedwater addition to the faulted steam generators needs to occur to minimize the mass and energy released to containment. To reduce the mass and energy release, a new Main Feedwater Isolation Valve (MFIV) with an automatically actuated operator is being added outside containment. The new MFIVs are designed to go full closed in 5 seconds or less to meet the containment steam line break safety analysis requirements discussed in LR Section 2.6.1, Primary Containment Functional Design.

The current containment pressure response analysis in FSAR Chapter 14, Safety Analysis, relies on the FRVs (including bypass valves) as the primary means of FW isolation and the FW Pumps and discharge valves plus tripping of the Condensate (CS) and Heater Drain (HD) pumps as the backup means of FW isolation. For EPU, the new safety related MFIVs will provide the primary means for FW isolation with the FRVs (including bypass valves) as the back up for FW isolation. This is required to minimize the mass and energy release from the FW System following a MSLB inside containment (LR Section 2.6.3.2, Mass and Energy Release Analysis for Secondary System Pipe Ruptures). No credit is taken for the isolation function of tripping the FW Pump, closure of the FW pumps discharge valves and the tripping of the Condensate and Heater Drain pumps in the mass and energy release analysis for a MSLB. TS 3.7.3 and Bases will be revised to reflect the addition of the FIVs as the primary means for FW isolation, redefining the FRVs and bypass valves as the back up means for FW isolation and removal of the tripping of the feedwater, condensate and heater drain pumps.

Condensate Cooler

The circulating water system supplies cooling water to the condensate cooler for maintaining the main generator hot gas temperature. The affect of EPU on the condensate cooler and hydrogen coolers will be evaluated as part of the plant modification process for the main generator rewind and implemented prior to EPU.

2.5.5.4.3 Conclusion

PBNP has assessed the effects of the proposed EPU on the condensate and feedwater system with modifications and concludes that its assessment has adequately accounted for the effects of changes in plant conditions on the design of the condensate and feedwater system. PBNP further concludes that the condensate and feedwater system will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The condensate and feedwater system maintains its compliance to PBNP GDCs 4, 53, and 57. Revisions to the Main Feedwater Isolation technical specifications are required to implement the revised condensate feedwater system isolation design. Based on this, PBNP concludes that the condensate and feedwater system will continue to meet the PBNP current licensing basis requirements. Therefore, PBNP finds the proposed EPU acceptable with respect to the condensate and feedwater system.

Table 2.5.5.4-1
Condensate and Feedwater System Operating Conditions

Parameter	Current Operating Condition	Extended Power Uprate Operating Condition
Condensate System		
Flow Rate, lb/hr	4,566,185	5,452,789
Condenser Pressure, inches Hg Abs @ Circ Water Temp., °F	1.20 @ 42.6°F	1.53 @ 42.6°F
Condensate Pump Discharge Pressure, psia	328	334
Condensate Supply Temperature, °F (FW Pump Suction)	348.3	362.1
Heater Drain System		
Heater Drain Pump Flow, lb/hr	2,099,753	2,714,826
Heater Drain Pump Discharge Pressure, psia	359	305
Feedwater System		
Flow Rate, lb/hr	6,665,938	8,112,108
Feedwater Pump Discharge Pressure, psia	1095	1067
Steam Generator Supply Temperature, °F	430.2	456.8

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

2.5.6.1.1 Regulatory Evaluation

The gaseous waste management systems 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 the condenser air removal system, the steam generator blowdown flash tank, and the containment purge exhausts; and the building ventilation system exhausts. The PBNP review focused on the effects that the proposed EPU may have on (1) the design criteria of the gaseous waste management systems, (2) methods of treatment, (3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exist.

The NRC's acceptance criteria for the gaseous waste management systems are based on:

- 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values;
- GDC 3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety;
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents;
- GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and
- 10 CFR Part 50 Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" (ALARA) criterion.

Specific review criteria are contained in SRP Section 11.3.

PBNP Current Licensing Basis

PBNP is committed to 10 CFR 50 Appendix A GDC 3. As stated in the Regulatory Evaluation section above, GDC 3 requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety. The Fire Protection Evaluation Report (FPER) serves as PBNP's fire plan as described in 10 CFR 50.48 and additionally documents PBNP's compliance with 10 CFR 50, Appendix A GDC 3. The purpose of the Fire Protection Program is to provide assurance, through defense-in-depth design, that a fire will not prevent the performance of necessary safe shutdown functions or significantly increase the risk of radioactive release to the environment during a postulated fire. The evaluation of the fire protection system and program for EPU conditions is described in LR Section 2.5.1.4, Fire Protection.

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Energy Industrial version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the Gaseous Waste Management (WG) system are as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

Radioactive gases are effectively processed to prevent their unmonitored release to the atmosphere. Gases are discharged intermittently at a controlled rate from the gas decay tanks through the monitored plant vent when required by plant inventory. A controlled release of gaseous waste from the waste disposal system requires that at least two valves be manually opened, one of which is normally locked shut. In addition, a discharge control valve is provided, which will trip shut on an effluent high radioactivity signal, thereby preventing an unanticipated release. Additional safety margin is provided by the use of ASME III, Class C materials and construction standards on significant components containing radioactive gases and USAS-B31.1 Section 1 piping and valves throughout the system.

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

The containment atmosphere, the auxiliary building vent, the drumming area vent, the condenser air ejector exhaust, the gas stripper building exhaust, the containment fan-coolers service water discharge, blowdown from the steam generators, the steam relief lines to atmosphere, the component cooling water, the waste disposal system liquid effluent, the spent fuel pool heat exchanger service water discharge, and the service water discharge are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment) are exhausted from vents which are monitored. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment, under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release during an accident. An outline of the procedures and equipment to be used in the event of an accident is presented in FSAR Section 11.5, Radiation Monitoring System and Section 11.6, Shielding Systems. The environmental monitoring program is described in Section 2.7, Environmental Radioactivity Studies.

CRITERION: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels (PBNP GDC 18).

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the drumming area vent. Radiation monitors are in continuous service in these areas to actuate high radiation alarms in the control room.

CRITERION: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

All waste handling and storage facilities are contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the limits of 10 CFR 100, as discussed in FSAR Section 11.2, Gaseous Waste management Systems, Section 11.1.5, Accidental Release, Recycle or Waste Liquid, and Section 11.2.5, Accidental Release, Waste Gas.

PBNP Technical Specification 5.5.11, Explosive Gas Monitoring Program, outlines the controls for potentially explosive gas mixtures contained in the on-service Gas Decay Tank. The program includes limiting the oxygen concentration in the on-service Gas Decay Tank and a surveillance program to ensure the limit is maintained.

Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), has been formalized in the Technical Specification 5.5.4, Radioactive Effluent Controls Program and Technical Specification 5.5.1, Offsite Dose Calculation Manual.

The PBNP gaseous waste management system is discussed in FSAR Sections 11.2. Gaseous Waste Management System, 11.5, Radiation Monitoring System, and Appendix I, 10 CFR 50, Appendix I Evaluation of Radioactive Releases From Point Beach Nuclear Plant.

In addition to the evaluations described in the FSAR, the PBNP's gaseous waste management system was evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER discusses gaseous waste management systems in Section 2.3.3.4, Waste Disposal Systems. Aging effects, and the programs credited with managing those effects, are described in Section 3.3.2.3.5.

2.5.6.1.2 Technical Evaluation

Introduction

Various systems are provided for the processing of Waste Gas (WG) including gas stripping, which remove radioactive gases and hydrogen from the primary coolant, condenser air ejector exhaust filtration and delay ductwork system, which reduce radioactive gases in air ejector effluent in the event of primary to secondary leakage, and gas decay tanks which hold gases for an adequate period of time to allow decay. Cover gases are also considered part of the waste gas system and include the nitrogen blanketing system and parts of the hydrogen gas system.

The facility includes those means necessary to maintain control over the plant gaseous radioactive effluents. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is based on 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur, and on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents (PBNP GDC 70). Radioactive gases are effectively reduced to prevent their unmonitored release to the atmosphere. Gases are discharged intermittently at a controlled rate from the gas decay tanks through the monitored plant vent when required by plant inventory. A controlled release of gaseous waste from the waste disposal system requires that at least two valves be manually opened, one of which is normally locked shut. In addition, a discharge control valve is provided which will trip shut on an effluent high radioactivity signal, thereby preventing an unanticipated release. Additional safety margin is provided by the use of ASME III, Class C materials and construction standards on significant components containing radioactive gases and ANSI/ASME-B31.1 piping throughout the system.

During plant operations, gaseous wastes will originate from:

- Degassing reactor coolant discharged to the CVCS
- Displacement of cover gases as liquids accumulated in various tanks
- Miscellaneous equipment vents and relief valves
- Sampling operations and gas analysis for hydrogen and oxygen in cover gases and gas decay tanks

Effluent from the gas compressors flows to one of four gas decay tanks. Before a tank is discharged to the environment, it is sampled and analyzed to determine and record the radioactivity to be released, and then is discharged to the plant vent at a controlled rate through a radiation monitor. During release, a trip valve in the discharge line is closed automatically by high radioactivity level indication in the plant vent.

Description of Analyses and Evaluations

The gaseous waste management systems and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation determined whether the EPU operating conditions are enveloped by the design parameters of the existing system/components.

Results

Implementation of EPU will have no significant effect on the generation of gaseous waste volume from the primary and secondary systems processed by the WG system. Plant system functions will not change, and assumptions related to volume inputs remain the same.

Implementation of EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which will impact the concentrations of radioactive nuclides in the WG System. However, this slight increase in radioactivity and the small volumes of radioactive liquid generated from leakage and planned drainage will have a minimal effect on the generation of radioactively contaminated gases. Consequently, the design capability of the WG system and the total volume capacity for handling gaseous radioactive waste will be unaffected by the uprate. As such, the Gaseous Waste Management system will be insignificantly impacted by the EPU. Although implementation of the EPU will impact the concentrations of radioactive nuclides in the WG System, in accordance with the FSAR, discharge streams will remain appropriately monitored with adequate safety features incorporated to preclude excessive radioactive releases and to maintain releases within the requirements of 10 CFR 20.

EPU has minimal effect on the quantity of gaseous waste being generated and has minimal effect on the average concentrations of radioactive materials released at the boundary of the unrestricted area. EPU does not add any new sources of potentially contaminated leakage or create any new flow paths or routes that would allow the contamination of systems designed for uncontaminated fluids.

EPU does not affect the plant design to control the release of radioactive effluents. It does not increase radioactive materials, except as discussed in LR Section 2.10.1, Occupational and Public Radiation Doses, or change the process to collect, process, control or monitor radioactive effluents, or the commitments to control the release of radioactive effluents.

EPU does not affect the plants design for the confinement of radioactivity. It does not increase the quantity of gaseous storage requirements.

EPU does not change the plants numerical guides for dose design objectives and limiting conditions for operation to meet ALARA criteria.

EPU does not affect the facility design that includes the means to maintain control over the plant radioactive gaseous effluents. Appropriate holdup capacity is provided for retention of gases, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is in accordance with 10 CFR 20 requirements for both normal operations and for any transients situation that might reasonably be anticipated to occur and on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence.

EPU does not change the means to monitor the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, or from accident conditions.

The environmental monitoring program is also not affected by EPU. This continues to confirm that radioactive releases have no significant impact to the environment and are ALARA.

Monitoring and alarm instrumentation for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels are not affected by EPU.

EPU does not change the provisions in the design of fuel and waste storage facilities such that there is no undue risk to the health and safety of the public from an accidental release of radioactivity. All waste handling and storage facilities remain contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the limits of 10 CFR 100, as discussed in FSAR Sections 11.2, Gaseous Waste Management Systems, 11.1.5, Accidental Release, Recycle or Waste Liquid, and 11.2.5, Accidental Release, Waste Gas.

PBNP Technical Specification 5.5.11, Explosive Gas Monitoring Program, outlines the controls for potentially explosive gas mixtures contained in the on-service Gas Decay Tank. The program includes limiting the oxygen concentration in the on-service Gas Decay Tank and a surveillance program to ensure the limit is maintained. This Technical Specification is not affected by EPU.

Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), has been formalized in the Technical Specification 5.5.4, Radioactive Effluent Controls Program, and Technical Specification 5.5.1, Offsite Dose Calculation Manual. EPU maintains these requirements.

The PBNP gaseous waste management system is discussed in FSAR Sections 11.2, Gaseous Waste Management System, 11.5, Radiation Monitoring System, and Appendix I, 10 CFR 50, Appendix I Evaluation of Radioactive Releases From Point Beach Nuclear Plant. The commitments contained herein are not affected by EPU.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP's radioactive waste management systems were evaluated for their impact on License Renewal evaluations. The gaseous waste management volumes, storage and handling conditions are not significantly impacted by the EPU. The increased concentration of radionuclides within the system has no significant effect on the aging of systems/components and there are no system/component modifications necessary. The impact of EPU on the radwaste effluents and associated doses to the public is being addressed in LR Section 2.10.1, Occupational and Public Radiation Doses.

SSC materials of construction, operating history and programs used to manage aging effects are documented in License Renewal Safety Evaluation Report for the PBNP, (NUREG-1839). Components of the radioactive waste management systems that are within the scope of License Renewal are described in Section 2.3.3.4 of NUREG-1839. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the radioactive waste management systems at EPU conditions does not add any new types of materials or previously unevaluated materials to the systems. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.6.1.3 Conclusion

PBNP has assessed the gaseous waste management systems. PBNP concludes that the assessment has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. PBNP finds that the gaseous waste management systems will continue to meet their design functions following implementation of the proposed EPU. PBNP further concludes that the gaseous waste management systems will continue to meet the PBNP requirements of 10 CFR 50 Appendix A GDC 3, 10 CFR 50.48, and PBNP GDCs 17, 18, 69, and 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the gaseous waste management systems.

2.5.6.2 Liquid Waste Management System

2.5.6.2.1 Regulatory Evaluation

The PBNP review of the liquid waste management system focused on the effects that the proposed EPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents.

The NRC's acceptance criteria for the liquid waste management systems are based on:

- 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values;
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents;
- GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and
- 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the ALARA criterion.

Specific review criteria are contained in SRP Section 11.2.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the Liquid Waste Management (WL) system is as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

A controlled release of liquid waste from the waste disposal system requires that at least two valves be manually opened, of which one of these valves is normally locked shut. In addition, a discharge control valve is provided which is designed to trip shut on an effluent high radioactivity signal from the discharge radiation monitor, thus preventing a release in excess of calculated amounts.

Radioactive fluids entering the waste disposal system are processed or collected in tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity, with an isotopic breakdown if necessary. Liquid wastes are processed as required and then released under controlled conditions. The system design and operation are directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

The containment atmosphere, the auxiliary building vent, the drumming area vent, the condenser air ejector exhaust, the gas stripper building exhaust, the containment fan-coolers service water discharge, blowdown from the steam generators, the steam relief lines to atmosphere, the component cooling water, the waste disposal system liquid effluent, the spent fuel pool heat exchanger service water discharge, and the service water discharge are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment) are exhausted from vents which are monitored. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment, under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release during an accident. An outline of the procedures and equipment to be used in the event of an accident is presented in PBNP FSAR Section 11.5, Radiation Monitoring System, and Section 11.6, Shielding System. The environmental monitoring program is described in Section 2.7, Environmental Radioactivity Studies.

CRITERION: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels (PBNP GDC 18).

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the drumming area vent. Radiation monitors are in continuous service in these areas to actuate high radiation alarms in the control room.

CRITERION: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

All waste handling and storage facilities are contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the limits of 10 CFR 100, as discussed in FSAR Section 11.2, Gaseous Waste Management Systems, Section 11.1.5, Accidental Release, Recycle or Waste Liquid, and Section 11.2.5, Accidental Release, Waste Gas.

Implementation of the overall requirements of 10 CFR 50, Appendix I, as to the utilization of radwaste treatment equipment to ensure that radioactive discharges are as low as is reasonably achievable (ALARA), has been formalized in the Technical Specification 5.5.4, Radioactive Effluent Controls Program, and Technical Specification 5.5.1, Offsite Dose Calculation Manual.

In addition to the evaluations described in the FSAR, PBNP's liquid waste management system was evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER discusses the Liquid Waste Management System in Section 2.3.3.4, Waste Disposal System. Aging effects, and the programs credited with managing those effects, are described in Section 3.3.2.3.5 Waste Disposal System – Aging Management Evaluation – Table 3.3.2-4.

2.5.6.2.2 Technical Evaluation

Introduction

The Liquid Waste Management System (WL) collects, processes, and prepares for disposal potentially radioactive liquid waste produced as a result of reactor operation.

The facility design includes those means necessary to maintain control over the plant radioactive liquid effluents. Appropriate holdup capacity is provided for retention of liquid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is based on 10 CFR 20 requirements, for both normal operations and for any transients that might reasonably be anticipated to occur, and on the basis of 10 CFR 100 dose level guidelines for potential reactor accidents of exceedingly low probability of occurrence (PBNP GDC 70). A controlled release of liquid waste from the waste disposal system requires that at least two valves be manually opened, of which one of these valves is normally locked shut. In addition, a discharge control valve is provided which is designed to trip shut on an effluent high radioactivity signal from the discharge radiation monitor, thus preventing a release in excess of calculated amounts.

Radioactive fluids entering the waste disposal system are processed or collected in tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity. Liquid wastes are processed as required and then released under controlled conditions. The systems design and operation are directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

During normal plant operation, the waste disposal system processes liquids from the following sources:

- Equipment drains, vents, and leaks
- Chemical laboratory drains
- Radioactive laundry and hot shower drains
- Decontamination area drains
- Chemical and Volume Control System (CVCS)
- Sampling system drains and local sample sinks
- Normal letdown
- Steam generator blowdown (if required by radioactivity content)
- Floor drains from the controlled areas of the plant
- Liquids used to transfer solid radwaste

The system also collects and transfers liquids from the following sources directly to the CVCS, to the auxiliary building sump, or back to the refueling water storage tank (depending on fluid content) for processing:

- Pressurizer relief tank
- Reactor coolant pump secondary seals
- Excess letdown (during startup)
- Accumulators
- Valve and reactor vessel flange leakoffs
- Refueling canal drains

Description of Analyses and Evaluations

The liquid waste management system and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation determined whether the EPU operating conditions are enveloped by the design parameters of the existing system/components.

Results

EPU conditions will not change the collection, segregation, processing, discharging or recycling of radioactive liquid wastes. Liquids leaking from process systems, liquids used during cleaning activities, liquid spills from maintenance activities, and liquids used during resin sluicing activities will continue to enter the WL System during all plant operating modes. EPU will not add or change any of the sources of potentially contaminated leakage, or create any new flow paths which would allow for the contamination of systems designed for uncontaminated liquids.

Equipment drains, vents and leaks are unchanged. New condensate and feedwater pumps are replacing the existing ones, but there is no anticipated change in drains or leaks of vent effluents. The same is true of the addition of the feedwater isolation valves, auxiliary feedwater pumps and the modification of the feedwater regulator valves.

EPU is not changing the frequency or quantity of chemical laboratory drains or radioactive laundry and hot shower drains. The decontamination area drains are unchanged.

The maximum potential percentage increase in coolant activity levels due to the EPU, for each chemical group identified in NUREG-0017, was estimated using the methodology and equations found in NUREG-0017, Revision 1, including a comparison of the change in power level and of plant coolant system parameters (such as reactor coolant mass, steam generator liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, steam generator blowdown flow rate, and steam generator moisture carryover) for both current and EPU conditions. Impacts are discussed in LR Section 2.10.1, Occupational And Public Radiation Doses.

EPU will impact the radioactivity content in the radwaste system effluents/process fluids. The change will have minimal effect on the volumes of radwaste generated; however, it will change the radioactivity content of the waste. The impact of EPU on the radwaste effluents and associated doses to the public is being addressed in LR Section 2.10.1, Occupational and Public Radiation Doses.

Sampling, letdown, floor drains, and liquids used to transfer solid radwaste are also not anticipated to change as a result of EPU.

The liquid waste from pressurizer relief tank, reactor coolant pump secondary seals, valve and reactor vessel flange leakoffs, and refueling canal drains are all anticipated not to change as a result of EPU.

As system flow rates, liquid inventories, and process conditions will remain within original design parameters, the Liquid Waste Management System will not be significantly affected by the EPU.

Implementation of EPU will have no significant effect on the generation of liquid waste volume from the primary and secondary systems processed by the WL system. Plant system functions will not change, and liquid waste volumes will be insignificantly affected by the EPU.

Implementation of EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which will impact the concentrations of radioactive nuclides in the WL System. However, this slight increase in radioactivity and the small volumes of radioactive liquid generated from leakage and planned drainage will have a minimal effect on the generation of radioactively contaminated sludge and resin solids. Consequently, the design capability of the WL system and the total volume capacity for handling liquid radioactive waste will be unaffected by the uprate. As such, the Liquid Waste Management system will be insignificantly impacted by the EPU.

EPU has minimum affect on the quantity of liquid waste being generated and minimal affect on the average concentrations of radioactive materials released.

EPU does not affect or change the following:

- The plant's design to control the release of radioactive effluents. It does not increase radioactive materials, except as described in LR Section 2.10.1, Occupational and Public Radiation Doses, or change the process to control radioactive effluents, or the commitments to control the release of radioactive effluents.
- The plant's design for the confinement of radioactivity. It does not increase the quantity of liquid requiring storage.
- The plant's numerical guides for dose design objectives and limiting conditions for operation to meet ALARA criteria.
- The design of the waste disposal system. There is only a minimal increase in liquid waste. All design attributes are unchanged.
- The monitoring and alarms of containment atmosphere, fuel and waste storage areas. The fuel and waste storage facilities remained designed to provide no undue risk to the health and safety of the public which could result from an accidental release of radioactivity.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The PBNP radioactive waste management system was evaluated for its impact on License Renewal evaluations. The liquid waste management system flow rates, water inventory and process conditions are not changed by the EPU and are within the original design parameters of the system. The increased concentration of radio-nuclides within the system has no significant effect on the aging of systems/components and there are no system/component modifications necessary. SSC materials of construction, operating history and programs used to manage aging effects are documented in License Renewal Safety Evaluation Report for PBNP (NUREG-1839), dated December 2005. Components of the radioactive waste management systems that are within the scope of License Renewal are described in Section 2.3.3.4 of NUREG-1839. Aging effects, and the programs used to manage the aging effects of these components are discussed in NUREG-1839, Section 3.3. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the radioactive waste management systems at EPU does not add any new types of materials or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.6.2.3 Conclusions

PBNP has assessed the liquid waste management system at EPU. PBNP concludes that the assessment has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the liquid waste management system to control releases of radioactive materials. PBNP finds that the liquid waste management system will continue to meet its design functions following implementation of the proposed EPU. PBNP further concludes that the assessment has demonstrated that the liquid waste management system will continue to meet the requirements of PBNP GDCs 17, 18, 69, and 70. Therefore, PBNP finds the proposed EPU acceptable with respect to the liquid waste management system.

2.5.6.3 Solid Waste Management System

2.5.6.3.1 Regulatory Evaluation

The PBNP review of the solid waste management system focused on the effects that the proposed EPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the solid waste management system.

The NRC's acceptance criteria for the solid waste management system are based on:

- 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values
- GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents
- GDC 63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels
- GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents
- 10 CFR Part 71, which states requirements for radioactive material packaging.

Specific review criteria are contained in SRP Section 11.4.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP specific GDC for the Solid Waste Management (WS) system is as follows:

CRITERION: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (PBNP GDC 70)

The WS system design and operation are directed toward minimizing releases of radioactive materials to unrestricted areas. The equipment is designed and operated to process solid radioactive wastes which result in a form which minimizes potential harm to personnel or the environment. Handling areas are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

CRITERION: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (PBNP GDC 17)

The containment atmosphere, the auxiliary building vent, the drumming area vent, the condenser air ejector exhaust, the gas stripper building exhaust, the containment fan-coolers service water discharge, blowdown from the steam generators, the steam relief lines to atmosphere, the component cooling water, the waste disposal system liquid effluent, the spent fuel pool heat exchanger service water discharge, and the service water discharge are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment) are exhausted from vents which are monitored. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment, under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release during an accident. An outline of the procedures and equipment to be used in the event of an accident is presented in FSAR Section 11.5, Radiation Monitoring System, and Section 11.6, Shielding Systems. The environmental monitoring program is described in FSAR Section 2.7, Environmental Radioactivity Studies.

CRITERION: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels (PBNP GDC 18).

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the drumming area vent. Radiation monitors are in continuous service in these areas to actuate high radiation alarms in the control room.

The PBNP solid waste management system is discussed in FSAR Section 11.3, Solid Waste Management System, Section 11.5, Radiation Monitoring System, and Section 11.6, Shielding Systems.

In addition to the evaluations described in the FSAR, PBNP's solid waste management system was evaluated for License Renewal. Systems and system component materials of construction, operating history and programs used to manage aging effects are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

The above SER discusses solid waste management systems in Section 2.3.3.4, Waste Disposal Systems. Aging effects, and the programs credited with managing those effects, are described in Section 3.3.2.3.5.

2.5.6.3.2 Technical Evaluation

Introduction

Operation of the solid waste management system is directed toward minimizing releases of radioactive materials to unrestricted areas. The equipment is designed and operated to process solid radioactive wastes resulting in a form which minimizes potential harm to personnel or the environment. Handling areas are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20.

The facility includes means necessary to maintain control over the plant solid radioactive effluents. Appropriate holdup capacity is provided for retention of all solid effluents, particularly where unfavorable environmental conditions can be expected to affect the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is justified on the basis of 10 CFR 20 requirements, for both normal and transient operations.

Spent resins from the demineralizers, filter cartridges and the concentrates from the evaporators are packaged and stored on-site until shipment off-site for disposal. Miscellaneous materials such as paper, plastic, wood, and metal are collected and shipped offsite for vendor supplied volume reduction (i.e., incineration, super compaction, metal melt, decontamination, etc.) followed by disposal.

Spent resins from CVCS and other system demineralizers are flushed to a shielded, lined stainless steel storage tank located in the auxiliary building basement. When the tank is full, the resin is dewatered and liquids from the dewatering operation are sent to the waste holdup tank. Following resin dewatering the tank and its shield are transferred by the seismically qualified auxiliary building crane to new fuel storage area where the resin is sluiced to a disposable cask liner. When the disposable liner is full, the liner is dewatered to meet disposal site or processor criteria. The disposable liner is then shipped offsite for processing or disposal at a suitable burial site.

Dry active waste may be stored in SeaLand containers in designated locations in the outside yard area of the Radiologically Controlled Area (RCA) before shipment. Also, B25 boxes or equivalent loaded with dry active waste may be stored in the outside yard area of the RCA before shipment. Routine surveys and inspections are performed to verify container integrity.

Description of Analyses and Evaluations

The solid waste management system and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation determined whether the EPU operating conditions are enveloped by the design parameters of the existing system/components.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

PBNP's radioactive waste management system was evaluated for their impact on License Renewal evaluations. The solid waste management volumes, storage and handling conditions are not significantly impacted by the EPU. The increased concentration of radionuclides within the system has no significant effect on the aging of systems/components and there are no system/component modifications necessary

SSC materials of construction, operating history and programs used to manage aging effects are documented in License Renewal Safety Evaluation Report for the PBNP, (NUREG-1839). Components of the radioactive waste management systems that are within the scope of License Renewal are described in Section 2.3.3.4 of NUREG-1839. There are no modifications or additions to system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the radioactive waste management systems at EPU conditions does not add any new types of materials or previously unevaluated materials to the systems. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Results

Implementation of EPU will have no significant effect on the generation of solid waste volume from the primary and secondary systems processed by the WS system. Plant system functions will not change, and assumptions related to volume inputs remain the same.

Implementation of EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which will impact the concentrations of radioactive nuclides in the WS System. This slight increase in radioactivity and the small volumes of radioactive liquid generated from leakage and planned drainage will have a minimal effect on the generation of radioactively contaminated sludge and resin solids. Consequently, the design capability of the WS system and the total volume capacity for handling solid radioactive waste will be unaffected by the uprate. As such, the solid waste management system will be insignificantly impacted by the EPU.

Additionally, quantities of low-level compressible radioactive wastes such as paper, disposable clothing, rags, floor coverings, plastics, cloth smears, and respiratory filters are not expected to increase as a result of EPU. The production of dry active wastes is not directly related to core power, and changes in system maintenance are not anticipated due to EPU conditions.

Although implementation of the EPU will impact the concentrations of radioactive nuclides in the WS System, in accordance with the FSAR, discharge streams will remain monitored with adequate safety features incorporated to preclude excessive radioactive releases and to maintain releases within the requirements of 10 CFR 20 and 10 CFR 100.

EPU has a minimal effect on the quantity of solid waste being generated.

EPU does not affect the plants design to control the release of radioactive effluents. It does not increase radioactive materials, except as discussed in LR Section 2.10.1, Occupational and Public Radiation Doses, or change the process to collect, process, control or monitor radioactive effluents, or the commitments to control the release of radioactive effluents.

The evaluation of the solid waste management system at EPU conditions demonstrates that PBNP will continue to meet the current licensing basis insofar as it requires that the systems be provided in the waste handling areas to detect conditions that may result in excessive radiation levels and to initiate appropriate safety actions. This design capability remains unchanged by EPU. Radiation monitors and alarms are provided as required to warn personnel of impending excessive levels of radiation or airborne activity. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses.

The evaluation of the solid waste management system at EPU conditions demonstrates conformance with the requirements of 10 CFR 71, insofar as the radioactive material packaging accounts for the maximum dose rate allowed on the surface of the container by shielding of the package in which the container is shipped. Packaging, shielding and handling of radioactive material are not changed by EPU; thus, compliance with 10 CFR 71 is not affected.

2.5.6.3.3 Conclusion

PBNP assessed the solid waste management system at EPU. PBNP concludes that the assessment has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the solid waste management system to process the waste. PBNP finds that the solid waste management system will continue to meet its design functions following implementation of the proposed EPU. PBNP further concludes that the assessment has demonstrated that the solid waste management system will continue to meet the requirements of PBNP GDCs 17, 18 and 70 and 10 CFR 71. Therefore, PBNP finds the proposed EPU acceptable with respect to the solid waste management system.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

2.5.7.1.1 Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies (e.g., diesel engine-driven generator sets) of sufficient capacity to perform their safety functions, assuming a single failure. The PBNP review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function.

The NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on:

- GDC 4, insofar as it requires that structures, systems, and components important-to-safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks.
- GDC 5, insofar as it requires that structures, systems, and components 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 17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure.

Specific review criteria are contained in SRP, Section 9.5.4.

PBNP Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predates those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC).

The PBNP equivalent GDC for 10 CFR 50 Appendix A GDC-4, 5, and 17 are as follows:

CRITERION: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (PBNP GDC 40)

CRITERION: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (PBNP GDC 4)

CRITERION: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (PBNP GDC 39)

The emergency diesel generator (EDG) fuel oil and transfer system is discussed in FSAR Section 8.8.3, Diesel Generator System Evaulation. There are two underground fuel oil storage tanks on site (T-175A/B). Each tank has a capacity of approximately 35,000 gallons. Sufficient fuel is normally maintained between the two tanks to allow one diesel to operate continuously at the required load for 7 days. At the minimum required level, which is 11,000 gallons in each emergency diesel fuel oil storage tank, one tank could provide enough fuel for an emergency diesel generator to operate for over 48 hours.

The onsite fuel oil capacity is sufficient to operate the standby emergency power sources for longer than the time to replenish the onsite supply from outside sources.

Transfer of oil from each fuel oil storage tank to automatically maintain level in the associated day tanks is accomplished by two 100% capacity motor-driven pumps in each train. Either fuel oil transfer pump is capable of serving either emergency generator in the same train by the use of normally closed manual cross-connect valves between the associated train day tanks. Fuel oil can also be transferred from one underground fuel oil storage tank to the other via the use of a fuel oil transfer pump and normally closed manual cross connect valves.

The tanks and piping needed for emergency diesel operation meet Class 1 seismic criteria.

The EDG Fuel Oil System is described in FSAR Section 8.8, Diesel Generator (DG) System, and Section 15.2.12, Fuel Oil Chemistry Control Program. Operability and surveillance requirements for the EDG Fuel Oil System are provided in PBNP Technical Specification 3.8.3, Diesel Fuel Oil and Starting Air, and PBNP Technical Requirements Manual (TRM) 4.12, Diesel Fuel Oil Program.

In addition to the evaluations described in the FSAR, PBNP's emergency diesel generator fuel oil and transfer system was evaluated for plant License Renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in:

- License Renewal Safety Evaluation Report (SER) of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839) dated December 2005

The above SER discusses the emergency diesel generator and fuel oil and transfer system in Section 2.3.3.8, Emergency Power System. The programs used to manage the aging effects associated with this system are discussed in Section 3.0.3.2.12 and 3.3 of the SER.

2.5.7.1.2 Technical Evaluation

Introduction

The emergency diesel generator fuel oil and transfer system is discussed in FSAR Section 8.8.3, Diesel Generator System Evaluation. Sufficient fuel is normally maintained between the two tanks to allow one emergency diesel generator to operate continuously at the required load for 7 days. At the minimum technical specification required level of 11,000 gallons in each emergency diesel oil storage tank, one tank could provide enough fuel for an emergency diesel generator to power essential equipment necessary to cool the core and maintain the containment pressure within the design value for a loss of coolant accident (coincident with a loss of offsite power) in addition to supplying sufficient power to shut down the unaffected unit (no accident is assumed in the second unit) for over 48 hours. Each fuel oil storage tank will be able to provide a minimum supply of fuel oil to allow operation of one EDG for over seven days at a maximum rated load or both EDGs at partial load for over five days. Manual cross-tie of the fuel oil storage tanks is also provided and will extend the available fuel oil onsite to more than seven days for any pair of EDGs operating at partial load.

The tanks and piping needed for emergency diesel operation meet Seismic Class 1 criteria.

Description of Analysis and Evaluations

The emergency diesel generator fuel oil storage and transfer system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. The evaluation is based on the system's required design functions and a comparison between the existing equipment ratings and the anticipated operating requirements at EPU conditions.

The independence and redundancy features of the system are not impacted by EPU and it continues to meet the PBNP current licensing basis (PBNP GDC 4). The system design for missile protection and protection against dynamic effects associated with the postulated rupture of piping will be maintained, refer to LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures (PBNP GDC 40).

Diesel fuel oil storage requirements are based on the fuel consumption rate associated with the ratings of the emergency diesel generators. The review of the diesel loads at EPU operation indicates that no emergency diesel generator modifications are required for EPU operation and the diesel generator loads remain within the diesel ratings. The TS 3.8.3 EDG fuel oil storage and transfer requirements will not be changed for EPU. The EDG fuel consumption will increase for EPU due to the EDGs increase in load. The increase in fuel consumption is based on operation for 48 hours at the 2000 hour rating for the G01/G02 EDGs and the 200 hour rating for the G03/G04 EDGs. The EPU fuel consumption for 48 hours remains less than the existing TS 3.8.3 minimum storage requirement of 11,000 gallons.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The emergency diesel engine fuel oil storage and transfer systems are within the scope of License Renewal. EPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the diesel fuel oil systems at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Results

The fuel oil inventory required to support the emergency diesel generators has been evaluated. Review of the electrical loads at EPU conditions indicate that the diesel loads remain within the ratings for the diesels. The maximum EDG fuel consumption for EPU for 48 hours remains less than the existing TS 3.8.3 minimum storage requirement of 11,000 gallons. The required quantity of available fuel will not change because there is no change in the design fuel oil consumption rate. No additional analysis is required to demonstrate the acceptability of the Emergency Diesel Engine Fuel Oil Storage and Transfer System and no modifications are required to support EPU operation. The emergency diesel generator electrical loading is further discussed in LR Section 2.3.3, AC Onsite Power System. Therefore, no changes are required to the existing emergency diesel engine fuel oil and transfer system and the system continues to comply with PBNP GDC 39.

The independence and redundancy features of the system are not impacted by EPU and it continues to meet the PBNP current licensing basis (PBNP GDC 4). The system design for missile protection and protection against dynamic effects associated with the postulated rupture of piping will be maintained, refer to LR Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and LR Section 2.5.1.3, Pipe Failures (PBNP GDC 40).

EPU does not add any new components nor does it introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the Fuel Oil Storage and Transfer System at EPU conditions does not add any new or previously unevaluated materials to the system. No new aging effects requiring management have been identified.

2.5.7.1.3 Conclusion

PBNP has reviewed the assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the assessment has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. PBNP concludes that the EDG Fuel Oil Storage and Transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of PBNP GDC 4, 39, and 40. Therefore, PBNP finds the proposed EPU acceptable with respect to the EDG Fuel Oil Storage and Transfer system.

2.5.7.2 Light Load Handling System (Related to Refueling)

2.5.7.2.1 Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The PBNP review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The PBNP review focused on the effects of the new fuel on system performance and related analyses.

The PBNP review focused on the effects of the new fuel on system performance and related analysis. The NRC's acceptance criteria for the LLHS are based on:

- GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection, and
- GDC 62 insofar as it requires that criticality is prevented.

Specific review criteria are contained in SRP Section 9.1.4 and guidance provided in Matrix 5 of RS-001, Revision 0.

Point Beach Nuclear Plant (PBNP) Current Licensing Basis

As noted in Final Safety Analysis Report (FSAR), Section 1.3, the GDC used during the licensing of PBNP predate those provided today in 10 CFR 50, Appendix A. The origin of the PBNP GDC relative to the Atomic Energy Commission proposed GDC is discussed in the FSAR, Section 1.3. The parenthetical numbers following the criterion description indicate the numbers of the Atomic Industrial Forum version of the proposed General Design Criterion (PBNP GDC)

The PBNP specific GDC for the Light Load Handling System are as follows:

Criterion: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (PBNP GDC 66)

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (PBNP GDC 68)

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (PBNP GDC 69)

As described in FSAR Section 9.4.2, Fuel Handling System, Design and Operation, the fuel handling system is designed to ensure adequate safety under normal operation and postulated accident conditions. Criticality in new and spent fuel storage areas is prevented both by physical separation of fuel assemblies and by the presence of borated water in the spent fuel storage pool. The reactor cavity, refueling canal and spent fuel storage pool are reinforced concrete structures with seam-welded stainless steel plate liners. These structures are designed to withstand the anticipated earthquake loadings as Seismic Class I structures so that the liner prevents leakage even if the reinforced concrete develops cracks. The fuel handling system is discussed in FSAR Section 9.4, Fuel Handling System.

In addition to the evaluations described in the FSAR, the fuel handling system was evaluated for the PBNP License Renewal. The evaluations are documented in:

- Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2, (NUREG-1839), dated December 2005

All portions of the Fuel Handling System that were determined to be in-scope for license renewal are addressed in the, Fuel Handling System, Section 2.3.3.13, Spent Fuel Cooling System, Section 2.3.3.3, the, Containment Unit 1/2 Building Structure, Section 2.4.1, or the, Primary Auxiliary Building Structure, Section 2.4.6.

2.5.7.2.2 Technical Evaluation

Introduction

The Fuel Handling system is described in FSAR Section 9.4, Fuel Handling Systems. The fuel handling systems provide a safe and effective means for transporting and handling reactor fuel from the time the fuel reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. The fuel handling system consists of the refueling cavity; the spent fuel pool; and the fuel transfer system. Special precautions are taken in all fuel handling operations to minimize the possibility of damage to fuel assemblies during transport to and from the spent fuel pool (SFP) and during installation in the reactor. All handling operations on irradiated fuel are conducted under water. The handling tools used in the fuel handling operations are conservatively designed and the associated devices are of a fail-safe design.

Special precautions are also taken in handling new fuel arriving on site to minimize the possibility of damage to fuel assembly during transport to new fuel vault and from there to the spent fuel pool. New fuel assemblies are received in a separate area that facilitates the unloading of new fuel assemblies from trucks. Each new fuel assembly is delivered to the reactor by transferring it into the spent fuel pool and taking it through the transfer system.

Storage of new fuel is addressed in LR Section 2.8.6.1, New Fuel Storage, and storage of spent fuel is addressed in LR Section 2.8.6.2, Spent Fuel Storage.

In addition, the spent fuel pool has an area set aside for accepting spent fuel shipping casks or dry storage casks. Cask loading is done under water. During refueling, spent fuel is removed from the transfer system and placed in storage racks with a long manual tool suspended from an overhead hoist. After a sufficient decay period, the fuel may be removed from storage and loaded into a shipping cask for removal from the site or loaded into a dry storage cask for temporary storage.

Commencing with Unit 1, Cycle 27 and Unit 2, Cycle 25, PBNP upgraded to the 14X14, 422V+ fuel design. This is the same fuel design that will be used for EPU operation.

Description of Analyses and Evaluations

Since the fuel assembly design for EPU operation is not changed from current configuration and no modifications to the fuel handling equipment will be required for EPU condition, no further analyses and evaluations for fuel weight comparison and handling equipment are required.

Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water.

In the spent fuel pool fuel storage area, administrative controls and geometric constraints ensure that the fuel assemblies are spaced in a pattern that prevents any possibility of a criticality accident. Also, administrative controls ensure carrying heavy objects over the fuel assemblies in the storage racks is conducted in accordance with NUREG-0612. In addition, administratively, only one fuel assembly can be handled at a given time over storage racks containing spent fuel. The motions of the cranes which move the fuel assemblies are limited to a relatively small area with low maximum speed. Caution is exercised during fuel handling to prevent the fuel assembly from striking another fuel assembly or structures in the containment or spent fuel pool. The fuel handling equipment suspends the fuel assembly in the vertical position during fuel movements, except when the fuel is moved through the transport tube.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The evaluation of the fuel handling system and the subsequent review and conclusions are discussed in Section 2.3.3.13, Fuel Handling, of the License Renewal SER, NUREG-1839, December 2005. The cranes, hoists, and lifting devices associated with fuel handling are discussed as an equipment group in SER Section 2.4.9, Cranes, Hoists, and Lifting Devices. The crane rails and supports that interface with building structural members are evaluated within the building that contains them.

EPU activities are neither adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the fuel handling system components at EPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for Aging Management Programs to account for the effects of EPU. Thus, no new aging effects requiring management are identified.

Results

The existing fuel assembly design is not altered; the weight of the fuel assembly remains the same. Therefore, it is evaluated to be acceptable for the fuel handling systems and equipment for both new (unirradiated) fuel and spent (irradiated) fuel.

Since the existing fuel assembly design is not altered, and there is no change to fuel handling devices and tools, there is no reduction or addition in shielding and radiation protection provided to personnel performing fuel-handling operations.

Since the fuel, fuel storage racks, physical storage separation distance, and boron in pool water are not altered, criticality is still prevented. Storage of new fuel is addressed in LR Section 2.8.6.1, New Fuel Storage, and storage of spent fuel is addressed in LR Section 2.8.6.2, Spent Fuel Storage.

2.5.7.2.3 Conclusion

PBNP has assessed the effects of the new and spent fuel on the ability of the LLHS to avoid criticality accidents and concludes that PBNP has adequately incorporated the effects of the new and spent fuel in the analyses at EPU. Based on this assessment, PBNP further concludes that the LLHS will continue to meet the requirements of PBNP GDCs 66, 68, and 69 for radioactivity releases and prevention of criticality accidents. Therefore, PBNP finds the proposed EPU acceptable with respect to the LLHS.