January 13, 2010

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10 CFR 50.90

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

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

License Amendment Request 261
Extended Power Uprate
Response to Request for Additional Information

References: (1) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)

(2) NRC letter to NextEra Energy Point Beach, LLC, dated December 22, 2009, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information from Reactor Systems Branch RE: Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML093500203)

NextEra Energy Point Beach, LLC (NextEra) submitted License Amendment Request (LAR) 261 (Reference 1) to the NRC pursuant to 10 CFR 50.90. The proposed amendment would increase each unit's licensed thermal power level from 1540 megawatts thermal (MWt) to 1800 MWt, and revise the Technical Specifications (TS) to support operation at the increased thermal power level.

The NRC staff determined that additional information was required (Reference 2). Enclosure 1 provides the NextEra response to the NRC staff's request. During a telephone conference between the NRC and NextEra on January 8, 2010, NextEra stated that the response to Question 2.8.5.2-2 would be provided via separate correspondence by January 22, 2010. The NRC stated that the schedule to provide this response was acceptable. Enclosure 2 provides a copy of Westinghouse Nuclear Safety Advisory Letter NSAL-07-10, "Loss-of-Normal Feedwater/ Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions," in response to Question 2.8.5.0-2. of Reference (2).

This letter contains no new Regulatory Commitments and no revisions to existing Regulatory Commitments.

The information contained in this letter does not alter the no significant hazards consideration contained in Reference (1) and continues to satisfy the criteria of 10 CFR 51.22 for categorical exclusion from the requirements of an environmental assessment.

In accordance with 10 CFR 50.91, a copy of this letter is being provided to the designated Wisconsin Official.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on January 13, 2010.

Very truly yours,

NextEra Energy Point Beach, LLC

FOR

Larry Meyer
Site Vice President

Enclosures

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE 1

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

The NRC staff determined that additional information was required (Reference 1) to enable the Reactor Systems Branch to continue its review of License Amendment Request (LAR) 261, Extended Power Uprate (EPU) (Reference 2). The following information is provided by NextEra Energy Point Beach, LLC (NextEra) in response to the NRC staff's questions.

Question 2.8.5.0-1.

Explain why a +1.4°F reactor coolant system (RCS) T_{avg} bias was applied for revised thermal design procedure analyses rather than treated statistically. Explain the effect of this assumption and compare to a statistical treatment of the same conditions.

NextEra Response

In the calculation of the Revised Thermal Design Procedure (RTDP) departure from nucleate boiling ratio (DNBR) design limit, variations in plant operating parameters, nuclear thermal parameters, and fuel fabrication parameters are considered statistically to obtain an overall departure from nucleate boiling (DNB) uncertainty factor. This factor is applied to the correlation limit to obtain a higher, more conservative 95/95 DNBR limit. The accident analyses are then performed at nominal conditions. However, only the random portion of the variation of these operating parameters is considered in the statistical calculation that determines the DNBR design limit. Biases are never included in the statistical determination of the DNBR design limit. They are accounted for separately in the DNBR analysis. Treatment of biases was described in response to Question 14 of the Request for Additional Information (RAI) on the RTDP topical report (Reference 3).

The T_{avg} bias can be accounted for in one of two ways. The first is to calculate a bounding DNBR penalty to offset the temperature bias. This DNBR penalty is accounted for by the retained DNBR margin in the Safety Analysis Limit DNBR. The alternative approach is to explicitly account for biases in the initial conditions and statepoints of the accident analysis.

In the Point Beach Nuclear Plant (PBNP) EPU analyses, for transients where the DNBR is conservatively approximated with the RETRAN code, the T_{avg} bias has been directly incorporated into the initial conditions modeled. For transients where a detailed DNBR calculation is performed with the VIPRE code, a bounding DNBR penalty for offsetting the T_{avg} bias has been accounted for in the Safety Analysis Limit DNBR of 1.38.

Question 2.8.5.0-2.

Please provide a copy of Reference 6 (page 2.8.5.0-13), Nuclear Safety Advisory Letter NSAL-07-10, "Loss-of-Normal Feedwater/Loss-of-Offsite AC Power Analysis PORV [Pressurizer Power-Operated Relief Valve] Modeling Assumptions," November 7, 2007.

NextEra Response

A copy of Westinghouse Nuclear Safety Advisory Letter NSAL-07-10 is provided in Enclosure 2.

Question 2.8.5.1-1.

How were the limiting break sizes, 0.59 ft2 (Unit 1) and 0.63 ft2 (Unit 2), determined for the analyses of Steam System Piping Failures at Full-Power?

NextEra Response

The analysis of the hot full power (HFP) steam line break (SLB) event performed in support of the PBNP EPU follows the standard Westinghouse methodology developed for this event. Under that methodology, the event is analyzed over a spectrum of break sizes in order to identify the most limiting overpower condition. The spectrum of breaks considered range from 0.1 ft^2 to 1.4 ft^2, where the maximum value is based on the steam generator exit nozzle flow restrictor flow area. In the PBNP analysis, this range of break sizes is explicitly modeled for both steam generator types (Model 44F for Unit 1 and Model Δ47 for Unit 2). The limiting case for each of the PBNP units corresponds to the case that reaches the highest peak core average heat flux, as this will yield the most limiting DNBR and kW/ft results for the event. Based on this, a break size of 0.59 ft^2 was found to be the most limiting for Unit 1, while a 0.63 ft^2 break was most limiting for Unit 2.

Question 2.8.5.1-2.

Describe the reactor vessel inlet mixing assumptions, and their bases, used in the analyses of Steam System Piping Failures and other asymmetric cooldown events.

NextEra Response

The steam line rupture core response analyses assume "design mixing" for the reactor vessel inlet and outlet plenums, as identified in the Westinghouse RETRAN methodology topical (Reference 4), Sections 3.4.2 and 3.4.4. The same design mixing model was used in the licensing basis steam line rupture analyses for PBNP with the LOFTRAN code. Detailed information regarding the basis for and conservatism of this model was provided in response to an NRC RAI, as documented in Appendix B of WCAP-14882-P-A; see letter NSD-NRC-98-5765, Question 4. As noted in the RAI response, this is the same mixing model previously approved by the NRC in their review of the LOFTRAN code (Reference 5) and the Westinghouse steam line break topical report (Reference 6). The Safety Evaluation Report for the Westinghouse RETRAN methodology (located in the front of Reference 4) discusses mixing in the section titled "Westinghouse Input Models." Note that for the PBNP units there are no other asymmetric cooldown events analyzed.

Question 2.8.5.1-3.

Since the OPΔT trip function is not qualified for a harsh environment caused by the steamline break, the applicant states that the Hi-1 containment pressure safety injection signal would generate a reactor trip signal before the time credited, in the analyses, for the OPΔT trip signal. What is the basis for this statement? What models and assumptions were used in containment pressure response analyses in order to yield conservatively late Hi-1 containment pressure safety injection signals?

NextEra Response

The PBNP HFP SLB analysis does not differentiate between breaks inside and outside containment; a single analysis conservatively addresses both scenarios. The analysis explicitly models the overpower ΔT (OPΔT) reactor trip and low steam line pressure safety injection signals. Although the OPΔT function may not be available for all inside-containment cases (as a harsh environment caused by larger-sized, inside-containment steam line breaks may affect its proper functioning), the analysis performed conservatively utilizes this function to determine limiting DNBR and kW/ft consequences for the event. To address the potential unavailability of the OPΔT function under these conditions, the analysis includes a model that integrates the break mass flow rate and flags the time at which the total steam releases reach 10,000 lbm. With this information, the time at which the 10,000 lbm value is reached has been confirmed to occur well before the time at which an OPΔT signal is generated.

As an example, for the limiting Unit 1 case (0.59 ft^2 break), if the break was assumed to occur inside containment, the steam releases reached a total of 10,000 lbm at 12.4 seconds after the start of the transient (Hi-1 containment pressure signal could have been used to generate a safety injection signal, which produces a reactor trip). However, reactor trip is conservatively delayed in the analysis until the OPΔT reactor trip setpoint is reached at 21.8 seconds after event initiation; rods begin to insert into the core 2 seconds later. A similar behavior was seen for Unit 2. The DNBR and kW/ft calculations performed for this event, which are both very sensitive to the time at which the reactor is tripped, are based on a conservatively delayed reactor trip on OPΔT. Based on this, the DNBR and kW/ft calculations for this event are conservative and apply to both inside and outside containment steam line breaks.

As for the calculation of the 10,000 lbm steam release value discussed above, a COCO computer code containment model was developed starting from the model used for the containment integrity analysis. Two changes were made to conservatively delay the time that the Hi-1 containment pressure setpoint was reached.

(1) The initial containment pressure was decreased to 14.7 psia.
(2) The surface area of the containment heat sinks was increased by 50%.

Applying mass and energy releases from a variety of steamline break sizes, it was determined that the Hi-1 containment pressure of 6 psig was always reached by the time that 10,000 lbm of steam had been released from the break.

Question 2.8.5.1-4.

What are the results of analyses for inside containment cases of Steam System Piping Failures at Full-Power that credit only the low steam line pressure safety injection signal?

NextEra Response

The analysis does not differentiate between breaks inside and outside containment (a single analysis conservatively addresses both scenarios) and the spectrum of break sizes was not analyzed with credit only for the low steam line pressure safety injection signal.

As discussed above in the response to RAI 2.8.5.1-3, the PBNP HFP SLB analysis explicitly models the OPΔT reactor trip and low steam line pressure safety injection signals. Although the OPΔT function may not be available for all inside-containment cases (as a harsh environment caused by larger-sized, inside-containment steam line breaks may affect its proper functioning), the analysis performed conservatively utilizes this function to determine limiting DNBR and kW/ft consequences for the event. As discussed above, the cases that rely on the OPΔT function for protection, were they to occur inside containment, would actually reach a reactor trip signal on a safety injection signal, derived from a hi-1 containment pressure signal, before the assumed trip time on OPΔT; however, this is conservatively ignored in the analysis.

The limiting case for each of the PBNP units corresponds to the case that reaches the highest peak core average heat flux, as this will yield the most limiting DNBR and kW/ft results for the event. Based on this, a break size of 0.59 ft^2 was found to be the most limiting for Unit 1, while a 0.63 ft^2 break was most limiting for Unit 2. These break sizes correspond to the largest break which results in reactor trip on OPΔT. As the break size is reduced, OPΔT continues to provide protection, but the severity of the transient lessens. As the break size is further reduced, no reactor trip signal will be generated, and a new equilibrium condition will be reached (similar to what occurs in the excessive steam load increase incident of Final Safety Analysis Report [FSAR] Section 14.1.7). The analysis results demonstrated that these cases were bounded by the limiting cases discussed above.

For break sizes larger than 0.59 ft^2 for Unit 1 or 0.63 ft^2 for Unit 2, protection is provided by a reactor trip resulting from a low steam line pressure safety injection signal. For these cases, a reactor trip signal is generated much earlier than those cases that rely on OPΔT. As such, the consequences of these cases are much less severe than those reported for the limiting cases. For example, whereas the highest peak core average heat flux is in the order of 125% of the nominal full-power value for the limiting case (0.59 ft^2 for Unit 1), a slightly larger break size (0.6 ft^2) for the same unit results in a peak core average heat flux of less than 102% of the nominal full-power value. Any break size greater than this would result in a faster actuation of the low steam line pressure safety injection function, with even less limiting results.

Question 2.8.5.1-5.

During a full-power steamline rupture-core response event, the main feedwater system flow will increase to match the steam flow until feedwater isolation occurs. It appears that the main feedwater system flow does not increase to match the steam flow, during a no-load steamline rupture-core response event. Describe how such a feedwater system response would affect a 1.4 ft2 no-load steamline break.

NextEra Response

The full power analysis considers a spectrum of break sizes, with the limiting case being an intermediate size break. For those cases, the feedwater control system is conservatively assumed to respond to the increased steam flow prior to reactor trip such that feedwater flow matches the steam flow. For the double-ended rupture analysis at no-load (post-trip) conditions, the feedwater control system would not be in operation. The analysis assumes that the main feedwater flow prior to isolation immediately increases to the nominal full-power value, which is much higher than the initial no-load feedwater flow. If the feedwater control valve in the faulted loop is conservatively assumed to go to its full-open position and all feedwater pumps were operating at full speed, the delivered flow could be somewhat higher as steam pressure falls in the affected steam generator. However, even though varying main feedwater flow affects the timing of the primary side depressurization and core heat flux transients, the peak core heat flux transient is not affected. Thus, the DNBR and peak kW/ft results would not be adversely affected by changes in the main feedwater flow assumption. This is consistent with the conclusion of the Westinghouse steam line break topical report (WCAP-9226-P-A, Rev. 1; Reference 6), Section 3.1.1.6, with respect to the sensitivity to feedwater system performance. (Note that Reference 6 was specifically prepared for 3-loop and 4-loop plants and is not part of the licensing basis for the 2-loop PBNP units. However, the results and conclusions of the topical are generally applicable and the overall steam line break analysis methodology used for PBNP is the same.)

Question 2.8.1.5-6.a)

The steamline break analysis discussion states that the core attains criticality before boron solution from the emergency core cooling system (ECCS) and accumulators enters the RCS (actually the core). Tables 2.8.5.1.2-1 and 2.8.5.1.2-2 indicate that the core attains criticality sometime after flow from the ECCS enters the RCS and shortly after the accumulators begin to inject. This indicates that the delivery of boron solution is determined by RCS pressure (not ECCS actuation signal delays or pump startup and valve opening times), and comes largely from the accumulators.

a) When does boron solution from the safety injection system enter the core?

NextEra Response

The core attains criticality before flow from the accumulators is injected. As shown on the referenced time sequence tables, criticality is attained at about 30 seconds, while the accumulators inject about a minute later. Furthermore, although emergency core cooling system (ECCS) injection begins just after 16 seconds, unborated water in the safety injection piping must be purged before boron is actually injected, which delays boron reaching the core.

a) Ignoring boron delivered from the accumulators, boron from the ECCS injection would reach the core (> 1 ppm) at about 95 seconds.

Question 2.8.1.5-6.b)

b) What would be the result of a smaller steamline break that would not depressurize the RCS to the accumulator injection setpoint?

NextEra Response

b) Even very small steam line break sizes result in depressurization of the reactor coolant system (RCS) to the accumulator setpoint, although it takes somewhat longer than in the design-basis double-ended rupture case. However, despite delayed accumulator actuation, the core heat flux increases at a slower rate for these cases and the peak core heat flux is lower. The analyzed case is the most-limiting condition for core response.

Question 2.8.1.5-6.c)

c) What would be the result of an even smaller steamline break that would not depressurize the RCS to the safety injection system shutoff head?

NextEra Response

c) As noted above, even very small steam line break sizes result in depressurization to below the safety injection (SI) system shutoff head. As long as there is an unisolable break on the secondary side, the primary system cools down and depressurizes until actuation of safeguards systems occurs.

Question 2.8.5.2-1.

In the Loss of Load event discussion, one of the listed acceptance criteria is stated as follows, "An incident of moderate frequency in combination with any single active component failure, or single operator error, is considered an event for which an estimate of the number of potential fuel failures is provided for radiological dose calculations. For such accidents, fuel failure is assumed for all rods for which the departure from nucleate boiling ratio falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There is no loss of function of any fission product barrier other than the fuel cladding." Why are there no analyses of anticipated operational occurrences combinations presented to show this criterion has been satisfied?

NextEra Response

As discussed with the staff during the preliminary RAI phone call, there is no requirement to analyze anticipated operational occurrences (AOO) combinations. Therefore, in LAR 261, Attachment 5, Section 2.8.5.2.1.2.2, on Page 2.8.5.2.1-6, the two paragraphs in the last bullet under Acceptance Criteria, as listed below, are deleted:

- An incident of moderate frequency in combination with any single active component failure, or single operator error, is considered an event for which an estimate of the number of potential fuel failures is provided for radiological dose calculations. For such accidents, fuel failure is assumed for all rods for which the departure from nucleate boiling ratio falls below

those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There is no loss of function of any fission product barrier other than the fuel cladding.

This criterion is satisfied by verifying that DNBR remains above the 95/95 DNBR limit.

Deletion of this bulleted section does not affect the acceptance criteria for this event.

Question 2.8.5.2-3.

If the restrictive acceptance criterion that the pressurizer does not become water solid were used for the Loss of Feedwater event, then why were the PORVs not modeled?

NextEra Response

The analysis of the Loss of Normal Feedwater/Loss of AC Power (LONF/LOAC) events performed in support of the PBNP EPU explicitly considers cases where the pressurizer power-operated relief valves (PORVs) are assumed to be operable, and cases where these are assumed to be unavailable; the same conservative acceptance criterion of preventing pressurizer filling is applied in all cases. The most limiting of these scenarios (without PORVs for LONF and with PORVs for LOAC) are reported in LAR 261. This approach is consistent with the guidance provided in NSAL-07-10 (Reference 7) (See Enclosure 2).

Question 2.8.5.4.5-1.

Please explain how, and in which operating modes, the Chemical and Volume Control System is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

NextEra Response

This statement is not intended to portray the chemical and volume control system (CVCS) as a protection system. The CVCS provides a means of reactivity control in the form of boric acid solution neutron absorber in the RCS. Potential failures in the CVCS are analyzed as part of the PBNP final safety analysis report (FSAR) Chapter 14 accident analysis. The functions of the CVCS are described in Section 9.3 of the PBNP FSAR.

Question 2.8.5.6-1.

Explain whether transient local and core-wide oxidation values calculated for the large and small break loss-of-coolant accident (LOCA) analyses include pre-transient oxidation. Discuss whether when considering pre-transient oxidation results remain within the 50.46 acceptance criteria.

NextEra Response

Response Related to Large Break Loss-of-Coolant Accident (LBLOCA) Only: The pre-transient oxidation was not factored into the maximum local oxidation or core-wide oxidation LBLOCA Automated Statistical Treatment of Uncertainty Method (ASTRUM) analyses results presented for PBNP Units 1 and 2. The maximum total of the normal operation (pre-transient) oxidation

and loss-of-coolant accident (LOCA) transient oxidation calculated, for any time in life, is considered below.

The pre-transient oxidation increases with burnup, from a low value at beginning of life to a maximum value at the discharge of the fuel (end of life). The calculated transient oxidation decreases with burnup; a negligible value will exist at end of life. The sum of the pre-transient plus transient oxidation has been confirmed to remain below 17% at all times.

Response Related to both LBLOCA and Small Break Loss-of-Coolant Accident (SBLOCA): The concern with core-wide oxidation relates to the amount of hydrogen generated during a LOCA. Because hydrogen that may have been generated pre-LOCA (during normal operation) will be removed from the reactor coolant system throughout the operation cycle, pre-existing oxidation does not contribute to the amount of hydrogen generated post-LOCA and therefore, does not need to be included when determining whether the calculated total core-wide oxidation meets the 1.0 percent criterion of 10 CFR 50.46(b)(3).

Response Related to SBLOCA Only: Due to low peak cladding temperatures and the absence of fuel rod burst, the maximum local transient oxidation is calculated to be 0.01% and 0.02% for PBNP Units 1 and 2, respectively. Pre-transient oxidation increases with burnup to a maximum value less than 17% at end-of-life. Therefore, because the transient oxidation is so low, the sum of the transient and pre-transient oxidation would remain below 17% at all times.

Question 2.8.5.6-2.

Discuss whether oxidation models for ASTRUM and NOTRUMP calculate cladding oxidation on both inner and outer cladding surfaces.

NextEra Response

ASTRUM Response: Local oxidation calculations are performed using the HOTSPOT code as discussed in Section 11-6-1 of the ASTRUM Topical Report (Reference 8). The HOTSPOT code calculates the cladding temperature at 80 locations on the hot fuel rod and models burst at a single axial location. Where burst is predicted to occur, inside and outside cladding reaction is simulated. A detailed discussion of the HOTSPOT model description is provided in Section 25-4 of the Code Qualification Document (Reference 9).

NOTRUMP Response: The NOTRUMP-EM fuel rod heatup code, SBLOCTA, calculates cladding oxidation on the outer cladding surface until fuel rod burst occurs. Once fuel rod burst occurs, double sided oxidation (on both the inner and outer cladding surfaces) is calculated around the burst node. The PBNP EPU analysis did not predict fuel rod burst for any of the transients; therefore, only single sided oxidation on the outer cladding surface was calculated.

Question 2.8.5.6-3.

Provide the result for core-wide oxidation for the small-break LOCA (SBLOCA) analysis.

NextEra Response

The hot rod axial average zirconium oxide thickness for all transients is negligible; reported as 0% in Tables 2.8.5.6.3-8 and 2.8.5.6.3-9 in the Attachment 5 of LAR-261, Extended Power Uprate (Reference 2). As such, the core wide oxidation is concluded to be less than the hot rod

Uprate (Reference 2). As such, the core wide oxidation is concluded to be less than the hot rod axial average due to the decrease from the core wide extension; meeting the acceptance criteria of < 1.0%.

Question 2.8.5.6-4.

The analysis of record SBLOCA analysis predicts a limiting peak cladding temperature (PCT) of 1205°F for the Unit 1 3-inch break. The extended power uprate (EPU) SBLOCA analysis predicts a limiting PCT of 1103°F. Compare assumed initial conditions, equipment functional capabilities and actuation setpoints to identify the causes of this significant decrease.

NextEra Response

The peak cladding temperatures (PCTs) for the analysis of record (AOR) (including a net of 48°F of 10 CFR 50.46 rackup items) and the EPU for each unit are compared below:

	AOR	EPU
Unit 1	1205°F (1157°F + 48°F)	1049°F
Unit 2	1094°F (1046°F + 48°F)	1103°F

While the EPU analysis analyzed a higher power, changes in other parameters lead to more favorable conditions that offset or more than offset the penalizing aspects of the higher power. The following table compares some of these parameters:

Parameter	AOR	EPU
Axial Offset	30%	13%
$F_{\Delta H}$ (hot channel enthalpy rise)	1.80	1.68
P_{HA} (maximum relative power in hot assembly)	1.667	1.62
SI Water Temperature (Refueling Water Storage Tank)	120°F	100°F

The benefits of these reduced parameters are:

- The reduction in axial offset by 17% forces more power below the mixture level allowing for more vapor generation/voiding and a resulting beneficial level swell. Further, the lower axial offset yields less vapor superheating above the mixture level and lower power at the PCT elevation.

- While the core average linear heat generation rate increases due to the increase in power, the nontrivial reductions in $F_{\Delta H}$ and P_{HA} reduce the ratios of power in the hot and hot assembly average rods to the core average rod resulting in more favorable hot rod and fluid channel boundary conditions.

- Reduced safety injection water temperature results in increased safety injection induced condensation which yields lower system pressures and therefore, higher safety injection flow rates.

Additionally, the AOR PCTs are reflective of two 10 CFR 50.46 rackup items; NOTRUMP mixture level tracking/region depletion errors (+13°F), and NOTRUMP bubble rise/drift flux model inconsistency corrections (+35°F). These rackup PCT penalties were generated based on conservative generic calculations that potentially over penalized the results. The EPU analysis was performed with the latest version of the NOTRUMP evaluation model codes capturing all 10 CFR 50.46 rackup changes as well as any items implemented on a forward-fit basis.

A comparison of significant parameters such as accumulator pressure, volume, and temperature, low pressurizer pressure setpoint, safety injection actuation setpoint, safety injection flows, and safety injection availability shows equivalent values or similar values that would have a negligible impact on results.

Question 2.8.5.6-5.

In light of the fact that Nuclear Regulatory Commission (NRC) approval of the SBLOCA analysis approval is required prior to EPU implementation, provide information to justify that any analytic changes effecting the noted reduction in PCT are the direct result of modifications that will be implemented following interim approval of requested EPU-related modifications.

NextEra Response

Based on the decision of NextEa not to employ a mid-cycle uprate for PBNP Unit 1, the current SBLOCA analysis of record will remain in place for both PBNP Units 1 and 2 until implementation of the EPU, at which point the SBLOCA EPU analysis will become the new analysis of record. Therefore, a response for the described interim condition is no longer applicable.

Question 2.8.5.6-6.

Explain what/how the SBLOCA analysis reflects revisions requested to Technical Specification (TS) 3.3.2, Function 6.e, TS 3.7.3, TS 3.7.5, and TS 3.7.6. Note that the original description of these change requests provided in the April 7, 2009, application for the EPU did not identify these TS Changes as affecting the SBLOCA analysis.

NextEra Response

While the PBNP SBLOCA EPU analysis did not credit auxiliary feedwater, the SBLOCA extended/cooldown analysis (based on the SBLOCA EPU analysis) used in the post-LOCA/long-term core cooling calculations did model auxiliary feedwater (Technical Specification (TS) 3.3.2 Function 6.e and TS 3.7.5). The closing time of the new main feedwater isolation valves (TS 3.7.3) was credited in the SBLOCA analysis for the main feedwater isolation and coastdown times. Changes to TS 3.7.6 related to the condensate storage tank do not impact the SBLOCA analysis.

Question 2.8.5.7-1.

List all operator actions credited for the anticipated transient without scram (ATWS) analysis.

NextEra Response

No operator actions are credited in the anticipated transient without scram (ATWS) analysis presented in LAR 261 (Reference 2).

Question 2.8.5.7-2.

For the period of time 250-300s following the ATWS initiating event when primary system pressure and temperature are decreasing, explain what phenomena hold down reactivity.

NextEra Response

During the 250-300 second period, the overall core reactivity remains significantly negative because the RCS vessel inlet temperature is still over 100 °F above its initial value, and the moderator temperature coefficient (MTC) modeled is -8 pcm/°F. Although the RCS temperature is decreasing during this time period and adding some positive reactivity, this addition is still small compared to the overall reactivity value. Thus, the reactivity is actually increasing and becoming less negative during this time period, but is still significantly negative overall. The nuclear power during this period is essentially stable due to decay heat generation in the core.

Question 2.8.5.7-3.

Explain what provides long-term shutdown capability following the ATWS.

NextEra Response

Long term shutdown capability after an ATWS event is discussed in Appendix B of WCAP-8330 (Reference 10), and in Section 9.4 of letter NS-TMA-2182 (Reference 11, successor to WCAP-8330). There are several mechanisms by which a plant may be shut down following an ATWS event. These include initiation of ECCS safety injection, an emergency boration process, a normal boration process, or a manual reactor trip.

Question 2.8.5.7-4.

Standard Review Plan Chapter 15.8 indicates that ATWS analytic results should be compared to the LOCA acceptance criteria provided in 10 CFR 50.46 regarding coolable geometry, peak cladding temperature, cladding oxidation, and hydrogen generation. Demonstrate conformance to these acceptance criteria.

NextEra Response

The section of the Standard Review Plan, Revision 2, dated March 2007, that discusses 10 CFR 50.46 criteria appears to only apply to evolutionary plant designs (Section II.3.C.i), and therefore would not need to be considered for PBNP.

PBNP compliance with 10 CFR 50.62 is documented in the NRC Staff's Safety Evaluation dated August 4, 1988 (Reference 12).

Question 2.8.5.7-5.

Describe how the loss of normal feedwater event is confirmed to be the limiting ATWS transient. Why is no other ATWS initiator evaluated?

NextEra Response

WCAP-8330 (Reference 10) and letter NS-TMA-2182 (Reference 11) presented results for several different ATWS events, including Rod Withdrawal, Loss of Normal Feedwater, Loss of AC Power, Loss of Load/Turbine Trip, Loss of Flow, Boron Dilution, RCS Depressurization, Excessive Load Increase, Rod Drop, and Startup of an Inactive Loop. The limiting ATWS events were determined to be the Loss of Normal Feedwater and Loss of Load/Turbine Trip. However, the Loss of Load ATWS is analyzed for plants with steam-driven main feedwater pumps where, as a result of the initiating turbine-trip event, a loss of condenser vacuum occurs with a consequential loss of main feedwater. For plants such as PBNP Units 1 and 2 with electric motor-driven main feedwater pumps, a loss of feedwater does not occur for a Loss of Load, making it a non-limiting event. Thus, only the Loss of Normal Feedwater event was analyzed for the PBNP EPU.

Question 2.8.5.7-6.

Explain the RCS flow transient. Describe the cause of the reduction in flow from 50-140 seconds, and provide the cause of the reactor coolant pump trip that follows the initial flow decrease.

NextEra Response

The flow decrease from 50 to 125 seconds is due to the decrease in coolant density as RCS temperature increases. The variable being plotted is a fraction of initial mass flow rate.

The reactor coolant pump coastdown at approximately 125 seconds is due to pump cavitation. As discussed in Section 2-4 of WCAP-8330 (Reference 10) and Section 3.2.2 of NS-TMA-2182 (Reference 11), pump cavitation is assumed to occur when the cold leg temperature approaches saturation. This does not impact the transient since the peak RCS pressure occurs prior to cavitation.

Question 2.8.5.7-7.

The Licensing Report states, "The ATWS evaluation for EPU assumed a [Point Beach Nuclear Plant] PBNP-specific [moderator temperature coefficient] MTC of 8pcm/°F that bounds 95 percent of the cycle. This value is consistent with that assumed in generic ATWS analyses."

Explain what compensating phenomena and operator actions provide acceptable reductions in risk from ATWS when the MTC is non-bounding of cycle operation.

NextEra Response

The use of a statistical MTC value in the PBNP EPU analysis is consistent with previous submittals (References 10, 11 and 13), and with the ATWS analysis guidance documented in References 14 and 15. In practice, there are several automatic or manual actions that would

mitigate the consequences of the event during the unfavorable portion of the cycle. These include control rod insertion either manually or via automatic rod control, and operator action to manually interrupt power to the control rod drive motor generator sets to initiate a reactor trip. There are also conservatisms in the analysis method that increase the severity of the predicted transient. Notably, the results would improve if a more detailed calculation of the core reactivity feedback was performed rather than using a point kinetics model that assumes bounding/conservative physics parameters with the exception of MTC.

Question 2.8.5.7-8.

Provide a list of initial conditions and plant parameters assumed in the ATWS analysis that differ from Point Beach-specific parameters. Provide the assumed value and compare it to the actual value that would be appropriate for analysis of Point Beach. Where any parameters are non-bounding, justify their use.

NextEra Response

Table 1 below lists the ATWS critical parameters, the corresponding values assumed in the analysis, and those associated with the PBNP EPU. The few differences between the numbers are discussed and justified.

Table 1: ATWS Analysis Critical Parameter Comparison

	PBNP EPU ATWS Analysis Assumption	PBNP EPU Plant-Specific Value	Comment
Core:			
Core, power (MWt)	1,800	1,800	
Core length (ft)	12	12	
Number of assemblies	121	121	
Reactor Coolant System:			
Nominal pressure, psia	2,250	2,250	
Nominal Flow, (gpm)	178,000	178,000	
Nominal Average Temperature (°F)	577.0	577.0	
No-Load Temperature (°F)	547	547	
Pressurizer:			
PORV steam flow capacity (lbs/hr) (at 2350 psia)	2-179,000 (each)	2-179,000 (each)	
PSV steam flow capacity (lbs/hr) (at 2500 psia)	2-288,000 (each)	2-288,000 (each)	
PORV opening setpressure, psia	2,350	2,350	
PSV, TS opening setpressure, psia	2,500*	2,500	

Table 1: ATWS Analysis Critical Parameter Comparison (continued)			
	PBNP EPU ATWS Analysis Assumption	PBNP EPU Plant-Specific Value	Comment
Secondary Systems:			
SG design parameters	Unit 1: Model 44F Unit 2: Model Δ47	Unit 1: Model 44F Unit 2: Model Δ47	
AFW flow, gpm	800	400 to 800	Sensitivity studies were analyzed for AFW flows ranging from 400 gpm to 800 gpm. Only a small difference in results was observed. The case that models 800 gpm is presented in LAR 261.
Capacity of atmospheric steam dumps, %	40	18 to 40	Sensitivity studies showed that a lower steam dump capacity provides a benefit in the analysis. The case presented in LAR 261 models 40%, which is conservative.
Main Steam Safety Valves TS Opening Setpressures, psig	1,085** 1,100** 1,105** 1,105**	1,085 1,100 1,105 1,105	
Main Steam Safety Valves Flow Capacities, lbm/hr	817,000 825,000 845,000 845,000	817,000 825,000 845,000 845,000	

Table 1: ATWS Analysis Critical Parameter Comparison (continued)			
	PBNP EPU ATWS Analysis Assumption	PBNP EPU Plant-Specific Value	Comment
AMSAC Response Times:			
Turbine Trip, sec	30	30	
AFW pumps start, sec	90	90	
Other			
Moderator Temperature Coefficient (MTC) for 95% of cycle, pcm/°F	-8	-8	

* The ATWS analysis adds valve accumulation to the opening setpoint.
**The ATWS analysis adds valve accumulation to these values.

Question 2.8.5.7-9.

Verify that actual component and actuation setpoint testing supports TS actuation values, and that the TS actuation values are used in the ATWS analyses. Specifically identify any differences between analyzed equipment actuation setpoints and respective TS values.

NextEra Response

The pressurizer safety valves and main steam safety valves are tested in accordance with the requirements of TS Surveillance Requirements (SR) 3.4.10.1 and SR 3.7.1.1, respectively.

The pressurizer safety valve and main steam safety valve settings assumed in the ATWS analysis are based on the proposed PBNP TS values. These are 2485 psig for the pressurizer safety valves, and 1085 psig, 1100 psig, 1105 psig, and 1105 psig for the main steam safety valves. Consistent with the previous submittals in References 10 and 11, and the guidance in Reference 15, the nominal TS pressurizer safety valve opening setpressure with no tolerance is modeled, along with a valve accumulation of 3% for steam relief and 10% for water relief. Valve accumulation is also included in the modeling of the main steam safety valve setpoints.

There are no other TS equipment actuation setpoints modeled in the ATWS analysis.

Question 2.8.5.7-10.

Confirm whether TS-permitted equipment out of service assumptions are reflected in the ATWS analyses.

NextEra Response

No equipment is assumed to be out of service in the ATWS analysis. Consistent with the previous analysis submitted in References 10 and 11, the plant is assumed to be in a reference configuration with no equipment failure other than that associated with the initiating event. This is further discussed in Section 3.0 of Reference 11.

Question 2.8.A-1

During its review of the RAVE implementation for Locked Rotor - Rods in departure from nucleate boiling (DNB) analyses, the NRC staff requested additional information (RAI) concerning the qualification of RAVE analysts (RAI 1), the nodalization of the VIPRE, RETRAN and SPNOVA models (RAI 2), and sensitivity analyses performed to demonstrate the conservatism of assumed voiding present in excess of 30 percent (RAI 7). Confirm that the information presented in response to the NRC staff's previous RAI is applicable to the EPU analyses as well. If this is not the case, justify any differences from the previous response.

NextEra Response

The information presented in response to the NRC staff's previous RAI for the PBNP LAR 241, Alternative Source Term (AST) (Reference 16), is applicable to the RAVE EPU analyses. This information includes:

RAI 1 - Qualification of the RAVE analysts
RAI 2 - Nodalizations of the RETRAN, VIPRE and SPNOVA models used in the RAVE analyses
RAI 7 - Addressing the RAVE SER 30% void fraction limit compliance for the Locked Rotor Overpressure analysis

In addition to the information provided for these AST RAIs, the information provided for the PBNP AST RAI 8 (SPNOVA SER compliance) is also applicable to the RAVE EPU analyses.

Question 2.8.A-2.a)

Condition 3 for implementation of RAVE requires that a plant be licensed to use each of the three constituent codes - VIPRE, RETRAN, and SPNOVA - for safety analyses. Detailed justification was provided for EPU implementation of VIPRE and RETRAN; analogous information was not provided for SPNOVA. Please provide the following information:

a) Has SPNOVA been implemented previously at Point Beach for licensing applications? If so, please describe the application and reference its NRC approval.

NextEra Response

a) SPNOVA has not been implemented at PBNP. As part of the RAVE methodology, the SPNOVA code was previously included in the PBNP AST LAR 241 submittal (Reference 17).

Question 2.8.A-2.b)

b) If SPNOVA has not been implemented previously at Point Beach for licensing applications, provide justification for its implementation that is analogous to that provided for implementation of VIPRE and RETRAN.

NextEra Response

b) Information supporting the use of the SPNOVA code for the PBNP licensing applications was submitted as part of the EPU LAR. Licensing Report Section 2.8.5.0.9, Computer Codes Used, contains the Advanced Nodal Code (ANC) descriptions, which apply to the

ANC and SPNOVA codes. The conditions, restrictions and limitations identified in the SPNOVA SER are generically addressed in WCAP-16259-P-A (Reference 18) for the NRC approved RAVE methodology. In addition, Appendix A to the EPU licensing report, Safety Evaluation Report Compliance, also provides supporting information for code use. The RAVE code SER compliance (Section A.8 of Appendix A), which applies to the RETRAN, SPNOVA and VIPRE codes, was included for completeness.

Additional information regarding the PBNP specific SPNOVA model SER compliance is provided as part of the PBNP AST RAI 8 (SPNOVA SER compliance) (Reference 16).

Question T.S.-1.a)

Low pressurizer pressure is credited to terminate the rod cluster control assembly (RCCA) drop accident. Note 2 of Table 2.8.5.0-5 states, "The generic two-loop RCCA drop analysis, which is applicable to PBNP, modeled the low pressurizer pressure reactor trip setpoint as a "convenience trip." The cases that actuated this function assumed dropped rod and control bank worth combinations that were non-limiting with respect to DNB. The fact that the plant-specific low pressurizer pressure reactor trip setpoint is lower than the value assumed in the generic analysis does not invalidate the applicability of the generic two-loop RCCA drop analysis to PBNP. Therefore, the low pressurizer pressure reactor trip setpoint value that was used in the generic two-loop RCCA drop analysis does not represent an analytical limit for this function for PBNP."

a) Please provide an electronic copy of WCAP-11394-P-A.

NextEra Response

a) An electronic copy of WCAP-11394-P-A was provided to the NRC via e-mail on January 5, 2010.

Question T.S.-1.b)

b) What trip is credited in the DNB-limiting case?

NextEra Response

b) There are no reactor trips credited in the limiting rod cluster control assembly (rod) drop cases. As discussed in WCAP-11394-P-A (Reference 19), with operation in automatic rod control mode, the typical plant response to a rod drop is an initial reduction in nuclear power, which is governed by the dropped rod worth, followed by an increase in power due to the automatic operation of the rod control system. Due to different power values sensed from the excore detectors (excore detector tilt), the rod control system may react to an indicated power that is less than the average power and cause the actual power to overshoot the original power level before dropping again and stabilizing at near the original power level. For each case, the limiting conditions occur during the period of power overshoot.

Question T.S.-1.c)

c) What limiting analysis is available to demonstrate the acceptability of a pressurizer low pressure trip setpoint of 1855 psia?

NextEra Response

c) The low pressurizer pressure reactor trip is not credited in any of the non-LOCA transient analyses that have been explicitly analyzed for the PBNP units. However, the low pressurizer pressure reactor trip setpoint of 1855 psia was used as the lower pressure boundary for the conditions of applicability of the core thermal limits, which are shown to be protected by the overtemperature ΔT and overpower ΔT reactor trip functions.

Question T.S.-2.

Are ECCS subsystem boron concentration levels proposed to change as a part of the expedited modifications? If not, explain how compliance with 10 CFR 50.36(c)(2)(ii)(B) is maintained in light of post-LOCA subcriticality analyses that presumably credit the increased TS minimum ECCS boron concentrations.

NextEra Response

The expedited review along with the mid-cycle implementation is no longer being pursued. Therefore, a response to RAI T.S.-2. is no longer required.

References:

(1) NRC letter to NextEra Energy Point Beach, LLC, dated December 22, 2009, Point Beach Nuclear Plant, Units 1 and 2 - Request for Additional Information from Reactor Systems Branch RE: Extended Power Uprate (TAC Nos. ME1044 and ME1045) (ML093500203)

(2) FPL Energy Point Beach, LLC letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)

(3) WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989.

(4) WCAP-14882-P-A (Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

(5) WCAP-7907-P-A (Proprietary), "LOFTRAN Code Description," April 1984.

(6) WCAP-9226-P-A, Revision 1 (Proprietary), "Reactor Core Response to Excessive Secondary Steam Releases," February 1998.

(7) NSAL-07-10, "Loss-of-Normal Feedwater / Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions", November 7, 2007.

(8) WCAP-16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

(9) WCAP-12945-P-A, Volume 1 Revision 2 and Volumes 2 through 5 Revision 1, "Code Qualification Document for Best-Estimate LOCA Analysis," March 1998.

(10) WCAP-8330, "Westinghouse Anticipated Transients without Trip Analysis," August 1974.

(11) Letter NS-TMA-2182 from T. M. Anderson of Westinghouse to Dr. Stephen H. Hanauer of the U. S. NRC, "ATWS Submittal," December 30, 1979.

(12) NRC letter to Wisconsin Electric Power Company Point Beach Nuclear Plant, dated August 4, 1988, Safety Evaluation by the Office of Nuclear Reactor Regulation, "Compliance with ATWS Rule 10 CFR 50.62."

(13) WCAP-15831-P-A, Revision 2, "WOG Risk-Informed ATWS Assessment and Licensing Implementation Process," August 2007.

(14) NUREG-0460, "Anticipated Transients Without Scram for Light Water Reactors," December 1978.

(15) Letter from Roger J. Mattson, NRC to Thomas M. Anderson, Westinghouse, February 15, 1979.

(16) NextEra Energy Point Beach, LLC letter to NRC, dated June 1, 2009, "Response to Request for Additional Information, License Amendment Request 241, Alternative Source Term" (ML091560413).

(17) NextEra Energy Point Beach, LLC letter to NRC, dated December 8, 2008, "Submittal of License Amendment Request 241, Alternative Source Term" (ML083450683).

(18) WCAP-16259-P-A (Proprietary), "Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis," Beard, C. L., et al., August 2006

(19) WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event," January 1990.

ENCLOSURE 2

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION 2.8.5.0-2.

WESTINGHOUSE NUCLEAR SAFETY ADVISORY LETTER NSAL-07-10
LOSS-OF-NORMAL FEEDWATER/LOSS-OF-OFFSITE AC POWER
ANALYSIS PORV MODELING ASSUMPTIONS
DATED NOVEMBER 7, 2007

4 pages follow

Nuclear Safety Advisory Letter

Westinghouse

This is a notification of a recently identified potential safety issue pertaining to basic components supplied by Westinghouse. This information is being provided so that you can conduct a review of this issue to determine if any action is required.

P.O. Box 355, Pittsburgh, PA 15230

Subject: **Loss-of-Normal Feedwater/Loss-of-Offsite AC Power Analysis PORV Modeling Assumptions**	Number: **NSAL-07-10**
Basic Component: Safety Analysis	Date: 11/07/2007
Affected Plants: See page 4	
Substantial Safety Hazard or Failure to Comply Pursuant to 10 CFR 21.21(a) Transfer of Information Pursuant to 10 CFR 21.21(b) Advisory Information Pursuant to 10 CFR 21.21(d)(2)	Yes ☐ No ☒ N/A ☐ Yes ☐ Yes ☐

Reference: 1. ANS-51.1/N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

SUMMARY

Westinghouse has investigated a safety analysis issue regarding the modeling of the pressurizer power-operated relief valves (PORVs) in the loss-of-normal feedwater (LONF) and loss-of-offsite AC (LOAC) power event analyses. LONF and LOAC analyses that assume normal operation of the pressurizer PORVs, consistent with the current Westinghouse procedures, are potentially affected. The investigation found that in some cases not modeling the PORVs can lead to more adverse results (i.e., a higher calculated pressurizer volume). Westinghouse has evaluated this issue for the LONF and LOAC analyses we have performed with either the RETRAN or LOFTRAN computer codes, and determined that it does not result in a substantial safety hazard.

This issue applies to plants that use the Westinghouse approach for the LONF and LOAC analyses, using either the RETRAN or LOFTRAN computer codes. Plants that use Combustion Engineering (CE) methodology are not affected by this issue.

Additional information, if required, may be obtained from Alan Macdonald, (412) 374-5413) or John Crane (412)-374-5750.

Originator:(s)

J. T. Crane
Regulatory Compliance and Plant Licensing

A. J. Macdonald
Transient Analysis

Approved:

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

ISSUE DESCRIPTION

Westinghouse has identified a potential non-conservative modeling assumption for the analysis of the loss-of-normal feedwater (LONF) and loss-of-all non-emergency AC power (LOAC) events. This assumption involves the modeling of the pressurizer power-operated relief valves (PORVs).

The LONF/LOAC analyses are performed to demonstrate that sufficient secondary-side heat removal capability exists to provide long term decay heat removal following reactor trip. When the secondary-side heat removal capability is degraded, the reactor coolant system (RCS) temperature increases, causing an insurge into the pressurizer which could result in a pressurizer water-solid condition. Subcooled water relief through the pressurizer safety valves (PSVs) could potentially cause damage to the valves, rendering the RCS boundary unisolatable. Conditions that result in the inoperability of the PSVs could be considered a more serious plant condition, resulting in a violation of the ANS Condition II acceptance criteria (Reference 1). Hence, the Westinghouse safety analyses for LONF/LOAC are conservatively performed to demonstrate that a water-solid pressurizer condition will not occur.

In prior safety analyses for these events, pressurizer PORVs were modeled. The PORVs are typically control systems designed for the primary function of controlling pressurizer pressure. Non-safety grade control systems are only modeled in the safety analyses if their normal operation leads to more limiting analysis results. Conversely, no credit is taken in the safety analyses for non-safety grade control systems that improve analysis results. The overall impact on the analysis has been found to be relatively small (less than 5% of the total pressurizer volume in the worse cases), and in many cases the impact on the analysis was negligible.

It should be noted that some plants have upgraded the PORVs to safety-grade status. However, credit for operation of the safety-grade PORVs in the analysis of these events would have to consider the potential single failure of a PORV and the potential need for timely operator action to unblock the PORV(s).

TECHNICAL EVALUATION

The pressurizer PORV modeling issue identified herein potentially affects the LONF and LOAC analyses performed using the Westinghouse modeling assumptions recommended for these events. Any plant using the Westinghouse analysis procedures, including those analyzed by Westinghouse licensees, may be potentially impacted by this issue. Plants marked with a "1" in Table 1 have been identified as potentially affected, and have been evaluated by Westinghouse. Plants marked with a "2" in Table 1 have been identified as potentially affected; however Westinghouse does not maintain scope for the LONF and LOAC analyses. Plants marked with a "3" in Table 1 have been addressed by Westinghouse for analyses that will be applicable in the future; however, Westinghouse does not maintain the currently applicable LONF and LOAC analyses. As discussed below in the Safety Significance section, the evaluation results demonstrate there is no substantial safety hazard.

SAFETY SIGNIFICANCE

Westinghouse has evaluated the effect of not modeling pressurizer PORVs for the LONF and LOAC analyses in which Westinghouse has cognizance of the licensing basis analysis. For these analyses, it was determined that sufficient margin exists in the analysis results such that the pressurizer does not reach water-solid conditions. Based upon these results and the discussion below, it has been concluded that this issue does not represent a substantial safety hazard (SSH) as defined in 10 CFR Part 21.

One acceptance criterion for an ANS Condition II event is that it should not generate a more severe plant condition. If the pressurizer becomes water solid, the potential exists for water to be discharged through the pressurizer PORVs or PSVs. If sustained subcooled water relief through the PSVs occurs, the valves may potentially be damaged such that the RCS pressure boundary may not remain intact. Should this occur, the consequences of these events could progress to resemble those associated with a more severe event, i.e., a small break loss-of-coolant accident (LOCA) in the pressurizer vapor space. While this is a violation of one of the acceptance criteria for a Condition II event, it is not considered a significant safety concern. Discharge of coolant out of the pressurizer relief system, especially for a post-reactor trip condition, is less severe than other ANS Condition III LOCA events currently analyzed. This is particularly true considering that the pressurizer is located on the hot leg and this break location is less severe than the cold leg breaks considered in the licensing basis LOCA safety analyses. Due to the fact that the possible consequences are bounded by an ANS Condition III LOCA event, it is concluded that the potential non-conservatism of modeling the PORVs does not represent a SSH or a failure to comply which would result in a SSH.

NRC AWARENESS

Westinghouse has not reported this issue to the USNRC.

RECOMMENDED ACTIONS

For plants identified in Table 1 for which Westinghouse has cognizance of the licensing basis analysis it has been determined that either the LONF/LOAC analyses have addressed this PORV modeling issue or the issue has been evaluated with acceptable results. For these plants, the LONF and LOAC sections of the FSAR should be reviewed for statements regarding the conservatism of modeling the PORVs, and updated as appropriate.

For plants identified in Table 1 for which Westinghouse is not cognizant of the current plant licensing basis analysis, the PORV modeling issue presented herein should be reviewed for potential applicability. If it is determined that this issue is applicable, analyses or evaluations should be performed to confirm the conservatism of modeling the PORVs for both the LONF and LOAC events.

Table 1: Potentially Affected Plants

Beaver Valley-1[1]	Prairie Island-1[1]	Mihama-1[2]
Beaver Valley-2[1]	Prairie Island-2[1]	Mihama-2[2]
Braidwood-1[1]	Robinson-2[2]	Ohi-1[2]
Braidwood-2[1]	Salem-1[1]	Ohi-2[2]
Byron-1[1]	Salem-2[1]	Takahama-1[2]
Byron-2[1]	South Texas-1[1]	Temelin-1[1]
Callaway[1]	South Texas-2[1]	Temelin-2[1]
Catawba-1[2]	Seabrook-1[1]	Almaraz-I[2]
Catawba-2[2]	Sequoyah-1[2]	Almaraz-II[2]
Comanche Peak-1[3]	Sequoyah-2[2]	Ascó-I[2]
Comanche Peak-2[3]	St. Lucie-2[1]	Ascó-II[2]
Cook-1[1]	V. C. Summer[1]	Vandellós-II[2]
Cook-2[1]	Surry-1[2]	Zorita[2]
Diablo Canyon-1[1]	Surry-2[2]	Beznau-1[1]
Diablo Canyon-2[1]	Turkey Point-3[1]	Beznau-2[1]
Farley-1[1]	Turkey Point-4[1]	Koeberg[1]
Farley-2[1]	Vogtle-1[1]	Krško[1]
Ginna[1]	Vogtle-2[1]	Sizewell B[2]
Shearon Harris[2]	Watts Bar-1[1]	Ringhals-2[2]
Indian Point-2[1]	Wolf Creek[2]	Ringhals-3[3]
Indian Point-3[1]	Angra-I[3]	Ringhals-4[2]
Kewaunee[1]	Kori-1[2]	Doel-1[2]
McGuire-1[2]	Kori-2[2]	Doel-2[2]
McGuire-2[2]	Kori-3[2]	Doel-4[2]
Millstone-3[1]	Kori-4[2]	Tihange-1[1]
North Anna-1[2]	Yonggwang-1[2]	Tihange-3[2]
North Anna-2[2]	Yonggwang-2[2]	Ulchin-1[2]
Point Beach-1[1]	Maanshan-1[1]	Ulchin-2[2]
Point Beach-2[1]	Maanshan-2[1]	

(1) Westinghouse has evaluated the impact of not modeling the PORVs on the LONF/LOAC licensing basis analyses and determined that margin exists within the analyses such that the pressurizer does not reach water-solid conditions.

(2) The LONF/LOAC licensing basis analyses for these plants was either not performed by, or is not currently maintained by Westinghouse, and therefore, Westinghouse cannot directly assess the effect for this plant.

(3) The LONF/LOAC analyses for Safety Analysis Transition programs has been evaluated by Westinghouse and it has been determined that margin exists within the analyses such that the pressurizer does not reach water-solid conditions. Westinghouse does not have cognizance of the pre-Transition Program analyses, and therefore cannot address the impact for the pre-Transition Program analysis.