NEXTera ENERGY POINT BEACH

June 11, 2010

NRC 2010-0063
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 April 22, 2010, Point Beach Nuclear Plant, Units 1 and 2 – Request for Additional Information from Probabilistic Risk Assessment Licensing Branch Re: Extended Power Uprate (TAC NOS. ME1044 and ME1045) (ML101040946)

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 license amendment would increase each unit's licensed thermal power level from 1540 megawatts thermal (MWt) to 1800 MWt, and revise the Technical Specifications to support operation at the increased thermal power level.

Via Reference (2), the NRC staff determined that additional information was required to enable the staff's continued review of the request. Enclosure 1 provides the NextEra response to the NRC staff's request for additional information.

Via LAR 261, Attachment 4, Item 13, a Regulatory Commitment was made to provide a backup compressed gas supply for the pressurizer auxiliary spray valve inside containment for each unit prior to operation at EPU conditions. NextEra has determined the pressurizer auxiliary spray valve for each unit will perform the desired function to open as it is currently configured. An emergency operating procedure change will be required to implement this feature as discussed in Enclosure 1.

Summary of Regulatory Commitments

The Regulatory Commitment contained in Reference (1), Attachment 4, Item 13 states:

- A backup compressed gas supply for the Pressurizer Auxiliary Spray Valve inside containment on each unit will be installed prior to operation of that unit at EPU conditions. See LR Section 2.13, Risk Evaluation.

NextEra is closing this Regulatory Commitment with no action as discussed in Enclosure 1.

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 June 11, 2010.

Very truly yours,

NextEra Energy Point Beach, LLC

Larry Meyer
Site Vice President

Enclosure

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 Probabilistic Risk Assessment Branch to complete 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 request.

APLA-1

As a result of performing the Individual Plant Examination (IPE), PBNP identified four modifications and six cost-effective improvements to the plant. Please describe modifications and improvements identified in the IPE, but not yet implemented, which affect the Extended Power Uprate (EPU) and address the risk impact for these issues.

NextEra Response

The four modifications and six cost-effective improvements identified in the Individual Plant Examination (IPE) have been implemented.

The four modifications identified in Section 1.3 of the Point Beach Nuclear Plant (PBNP) IPE submittal (Reference 3) and referred to in Section 6 of the IPE Staff Evaluation Report (Reference 4) are:

- Installation of an additional safety-related station battery
- Installation of a non-safety-related battery
- Installation of alternate shutdown switchgear with associated 13.8 kV system upgrades
- Upgrades of the gas turbine generator and main steam isolation valves

These modifications were installed after the September 5, 1990 design freeze date for the probabilistic risk assessment (PRA) model to be used in the IPE. As such, the results presented in the IPE submittal do not include the effects of these modifications. However, they were installed prior to the date of the IPE submittal. They were listed in the IPE submittal to acknowledge that the core damage frequency (CDF) at the time of the IPE submittal was lower than the CDF corresponding as of the design freeze date.

The six cost-effective improvements identified in Section 6.2 of Reference (3) and referred to in Section 6 of Reference (4) are as follows:

- Procedure changes for transferring to containment sump recirculation
- Procedure changes for alignment of alternate water sources for refilling the condensate storage tanks (CSTs)
- Modification to allow rapid connection of fire water to refill the CSTs
- Modification to reverse the control building access tunnel doors and frames to open towards the turbine halls
- Modification to install two additional emergency diesel generators (EDGs)
- Incorporation of the Westinghouse Owner's Group (WOG) severe accident management guidelines (SAMG) into PBNP's severe accident management program

The improvements have been implemented at the plant in the manner discussed below:

- The emergency operating procedure for transfer to containment sump recirculation for low head injection was revised to provide greater assurance that the emergency core cooling system (ECCS) switchover steps can be performed in the time required.
- Several emergency operating procedures and an abnormal operating procedure were revised to provide directions to establish an alternate source of water to the suction of the auxiliary feedwater (AFW) pumps (service water or fire water).
- Modifications were completed to allow rapid connection of fire water to the suction piping of the AFW pumps.
- A modification was completed to reverse the direction of the control building access tunnel doors and frames to open towards the turbine hall.
- Two additional EDGs were installed.
- The lesson plan for training on SAMG references the WOG SAMG Instructor's Lesson Plan, "Overview of the WOG SAMG."

<u>APLA-2</u>

EPU Licensing Report Section 2.13.1.3 states PBNP internal events Probabilistic Risk Assessment (PRA) received a formal industry Westinghouse Owners Group (WOG) peer review in June 2001. Please identify the guidelines or standard used during this peer review.

<u>NextEra Response</u>

The WOG peer review followed a process adapted by the WOG from the review process that was originally developed and used by the Boiling Water Reactor Owners Group (BWROG). This was subsequently broadened to be an industry-applicable process through the Nuclear Energy Institute (NEI) Risk Applications Task Force. The review was conducted under WOG sponsorship as part of a program to perform such reviews for operating domestic WOG member plants. The guidelines used are contained in the following:

- BWROG-97026, Transmittal of BWR Owners' Group Document, 'PRA Peer Review Certification Implementation Guidelines,' Boiling Water Reactor Owners Group, January 31, 1997.

- NEI-00-02, Industry PRA Peer Review Process, Nuclear Energy Institute, January 2000.

APLA-3

WOG PRA peer review items DA-03, DA-05, and DA-06 focuses on common cause failure (CCF) groupings and CCF applicability in the PBNP PRA. DA-05 discusses service water pumps. Provide justification for excluding potential CCF contributions for running service water pumps, explain why running and standby pumps are decoupled, and why the global CCF event for service water pumps does not include the probability of pumps two through five failing. DA-06 discusses common cause failures of diesel generators. Provide an explanation of how maintenance crew CCF is modeled for diesels G-01, G-02, G-03, and G-04.

NextEra Response

For the service water fault tree models used for the EPU analysis, initially-running and initially-standby service water (SW) pumps were considered as one common cause group. That is, common cause failure (CCF) of all six pumps running was calculated in the models regardless of the initial operating status of the pumps. Similarly, CCF of all six pumps failing to start (or restart following a loss of power), was calculated regardless of the initial operating status of the pumps with one exception.

The exception to including CCF of all six SW pumps to start is for the calculation of the initiating event frequency for loss of SW. The fault tree model used to develop the loss of SW initiating event frequency assumes that any initially operating SW pump that fails is not restarted. However, the fault tree model development for common cause of the SW pumps that are initially in standby considers the SW pumps as a group of six components. The PRA model used in LAR 261 explicitly includes CCFs for starting and running SW pumps.

As described in LAR 261, Attachment 5, Section 2.13, Risk Evaluation, and summarized in the NextEra Response to APLA-3 above, modeling and quantification of the common cause failure probability considers only failure of all pumps, not intermediate combinations, i.e., CCFs involving combinations of only two through five pumps. To evaluate how common cause failures of all potential combinations could affect the post-EPU PRA, a sensitivity study was performed. In this sensitivity study, all six SW pumps were treated as a single common cause group. First, the fault tree models were changed to include all combinations of CCFs related to the SW pump groupings. Next, the affect of the changes on the pre-EPU models was calculated. The results are shown below:

	Unit 1			Unit 2		
	Base LAR Model	Revised SW CCF Modeling	Change from Results in LAR	Base LAR Model	Revised SW CCF Modeling	Change from Results in LAR
CDF (per year)	3.7E-05	3.7E-05	--	4.4E-05	4.4E-05	--
LERF (per year)	3.3E-06	3.3E-06	--	3.3E-06	3.3E-06	--

A comparison of the significant cutsets for CDF and large early release frequency (LERF) indicated only minor changes in the contributions to each risk metric.

Next, the effect of not considering risk reduction measures on the post-EPU model was calculated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Revised SW CCF Modeling	Change from Results in LAR	Post-EPU with AFW Mods	Revised SW CCF Modeling	Change from Results in LAR
CDF (per year)	5.6E-05	5.6E-05	--	6.4E-05	6.4E-05	--
LERF (per year)	4.5E-06	4.5E-06	--	4.5E-06	4.5E-06	--

A comparison of the significant cutsets for CDF and LERF indicated only minor changes in the contributions to each risk metric.

Finally, the effect of risk reduction strategies on the post-EPU was evaluated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW and Risk-Reduction Mods	Revised SW CCF Modeling	Change from Results in LAR	Post-EPU with AFW and Risk-Reduction Mods	Revised SW CCF Modeling	Change from Results in LAR
CDF (per year)	3.5E-05	3.5E-05	--	3.7E-05	3.7E-05	--
LERF (per year)	2.2E-06	2.2E-06	--	2.2E-06	2.2E-06	--

A comparison of the significant cutsets for CDF and LERF indicated only minor changes in the contributions to each risk metric.

As discussed in LAR 261, Attachment 5, Section 2.13, Risk Evaluation, the G01/G02 and G03/G04 EDGs have different locations and different cooling systems. These factors are typically considered when grouping components into common cause groups. In the discussion of this section, it is also noted that CCFs between components in the fuel oil supply were included in the model. Maintenance crew CCF is implicitly included in the common mode failure of G01/G02 as well as the common mode failure of G03/G04. The maintenance crew actions were not considered sufficiently strong to warrant grouping the otherwise dissimilar components into a larger group of four. Nonetheless, a sensitivity study was performed to evaluate the potential effect of different common cause groupings for the EDGs. In this sensitivity study, all four EDGs were treated as a single common cause group. First, the fault tree models were changed to include all combinations of CCFs related to the EDG groupings. Next, the affect of the changes on the pre-EPU models was calculated. The results are shown below:

	Unit 1			Unit 2		
	Base LAR Model	Revised EDG CCF Modeling	Change from Results in LAR	Base LAR Model	Revised EDG CCF Modeling	Change from Results in LAR
CDF (per year)	3.7E-05	3.8E-05	+1E-06	4.4E-05	4.5E-05	+1E-06
LERF (per year)	3.3E-06	3.3E-06	--	3.3E-06	3.3E-06	--

A comparison of the significant cutsets for CDF and LERF indicated only minor changes in the contributions to each risk metric.

Next, the effect of not considering risk reduction measures on the post-EPU model was calculated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Revised EDG CCF Modeling	Change from Results in LAR	Post-EPU with AFW Mods	Revised EDG CCF Modeling	Change from Results in LAR
CDF (per year)	5.6E-05	5.8E-05	+2E-06	6.4E-05	6.5E-05	+1E-06
LERF (per year)	4.5E-06	4.5E-06	--	4.5E-06	4.5E-06	--

A comparison of the significant cutsets for CDF and LERF indicated only minor changes in the contributions to each risk metric.

Finally, the effect of risk reduction strategies on the post-EPU model was evaluated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW and Risk-Reduction Mods	Revised EDG CCF Modeling	Change from Results in LAR	Post-EPU with AFW and Risk-Reduction Mods	Revised EDG CCF Modeling	Change from Results in LAR
CDF (per year)	3.5E-05	3.6E-05	+1E-06	3.7E-05	3.8E-05	+1E-06
LERF (per year)	2.2E-06	2.2E-06	--	2.2E-06	2.2E-06	--

A comparison of the significant cutsets for CDF and LERF indicated only minor changes in the contributions to each risk metric.

Based on the results summarized above, changing the common cause modeling for SW pumps and EDGs will not change the overall results or conclusions presented in LAR 261.

The effect on the PRA models considering the combined effects of SW pump common cause groups and EDG groups is considered in conjunction with air compressors in the NextEra Response to APLA-4.

APLA-4

WOG PRA peer review item QU-10 and DA-05 focuses on CCF grouping and calculations for loss of instrument air. The peer review states that loss of instrument air is the leading CCF contributor to core damage for the PBNP PRA. EPU Licensing Report Section 2.13.1-63 states instrument air affects operation of Auxiliary Feedwater, feed and bleed cooling, and Reactant Coolant System depressurization. Provide a brief description explaining how the CCF is calculated for all four air compressors and explain how intermediate CCF is modeled in the PBNP PRA for the air compressors. (i.e., failure of 2 of 4, failure of 3 of 4). Provide a sensitivity analysis to explain the impact on EPU.

NextEra Response

The PBNP PRA uses two fault trees to model air systems. The first fault tree models the failure of the air systems to supply adequate air when the air systems are required to support operation of other systems. The second fault tree models the failure of the air systems resulting in an initiating event. The fault tree model for the air systems supporting operation of other systems contains one basic event that represents the global failure of all four air compressors that was calculated using the Multiple Greek Letter method. No CCF combinations of two or three compressors are included. The fault tree model to quantify the loss of instrument air (IA) initiating event frequency contains no CCF events for the air compressors.

As described in LAR 261, Attachment 5, Section 2.13, Risk Evaluation, and summarized above, modeling and quantification of the CCF probability considers only failure of all compressors, not intermediate combinations, i.e., CCFs involving combinations of only two or three compressors. Also, the initiating event frequency calculation for loss of IA does not include CCF of air compressors. To evaluate how common cause failures of all potential combinations could affect the post-EPU PRA, a sensitivity study was performed. In this sensitivity study, all four air compressors were treated as a single common cause group. First, both of the fault tree models, including the fault tree for calculating the initiating event frequency of loss of IA, were changed to include all combinations of CCFs related to the air compressor groupings. Next, the impact of the changes on the pre-EPU models was calculated. The results are shown below:

	Unit 1			Unit 2		
	Base LAR Model	Revised IA CCF Modeling	Change from Results in LAR	Base LAR Model	Revised IA CCF Modeling	Change from Results in LAR
CDF (per year)	3.7E-05	6.4E-05	+2.7E-05	4.4E-05	7.1E-05	+2.7E-05
LERF (per year)	3.3E-06	3.3E-06	--	3.3E-06	3.3E-06	--

The results above show that the changes to IA and service air compressor common cause group modeling result in only insignificant changes to LERF numeric results. In addition, a comparison of the significant cutsets for LERF indicated only minor changes in the contributions of each event to this risk metric.

For the CDF risk metric, however, changes to the common cause group modeling caused significant changes to the results. These changes occur because the original base models did not include common cause failure of the air compressors as a failure mode for the loss of IA initiating event. The increase in CDF, shown above, results almost entirely from additional failures that represent loss of IA initiating events. The effect of these additional cutsets on the comparisons used for the EPU evaluations is addressed below.

Next, the impact of not considering risk reduction measures on the air compressor modeling on the post-EPU model was calculated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Revised IA CCF Modeling	Change from Results in LAR	Post-EPU with AFW Mods	Revised IA CCF Modeling	Change from Results in LAR
CDF (per year)	5.6E-05	8.3E-05	+2.7E-05	6.4E-05	9.1E-05	+2.7E-05
LERF (per year)	4.5E-06	4.5E-06	--	4.5E-06	4.5E-06	--

The results above show that the changes to IA and service air compressor common cause group modeling result in only insignificant changes to LERF numeric results. In addition, a comparison of the significant cutsets for LERF indicated only minor changes in the contributions of each event to this risk metric.

For the CDF risk metric, however, changes to the common cause group modeling caused significant changes to the results. These changes occur because the original base models did not include CCF of the air compressors as a failure mode for the loss of instrument air initiating event. The increase in CDF shown above, results almost entirely from additional failures that represent loss of IA initiating events. The additional loss of IA related cutsets for this case were compared to the additional cutsets generated for the pre-EPU base case described above. This comparison showed that the additional cutsets generated by changing the common cause grouping for air compressors were identical for the pre-EPU and post-EPU models. Therefore, it is concluded that changing the common cause grouping for air compressors, while changing the value of the CDF risk metric, has no significant impact on the change in risk resulting from the EPU.

Finally, the effect of risk reduction strategies on the post-EPU model was evaluated. The results are shown in the table below:

	Unit 1			Unit 2		
	Post-EPU with AFW and Risk-Reduction Mods	Revised IA CCF Modeling	Change from Results in LAR	Post-EPU with AFW and Risk-Reduction Mods	Revised IA CCF Modeling	Change from Results in LAR
CDF (per year)	3.5E-05	3.5E-05	--	3.7E-05	3.8E-05	+1E-06
LERF (per year)	2.2E-06	2.2E-06	--	2.2E-06	2.2E-06	--

The results above show that the changes to IA and service air compressor common cause group modeling result in only insignificant changes to LERF numeric results. In addition, a comparison of the significant cutsets for LERF indicated only minor changes in the contributions of each event to this risk metric.

Only insignificant changes to the CDF numeric results are seen and a review of the final cutsets shows only minor changes in the overall contributions for each event. Also, comparing the risk values above with the pre-EPU risk values shown above, the risk reduction strategies planned for the EPU project will result in an overall reduction in risk even considering the uncertainty of modeling air compressor common CCFs. Therefore, changing the common cause grouping for air compressors has no significant impact on the change in risk resulting from the EPU. For this analysis, the replacement air compressor was included in the common cause grouping with the existing three air compressors even though the replacement compressor would be a completely different design and vintage. Eliminating the replacement air compressor from the common cause grouping would be expected to result in a lower risk.

A final sensitivity study was performed to consider the combined effects of changes to common cause groupings for the air compressors, EDGs and SW pumps. For this sensitivity study, the modeling changes described above, as well as the modeling changes delineated in the NextEra Response to APLA-3, was combined and the PRA models quantified. First, the evaluation used all of the logic changes to quantify the impact of the changes on the pre-EPU models. Next, the effect on the post-EPU model is calculated. Finally, the affect on the post-EPU model with risk reduction strategies is evaluated.

The combined affects of the common cause grouping changes on the pre-EPU models are shown below:

	Unit 1			Unit 2		
	Base LAR Model	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR	Base LAR Model	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR
CDF (per year)	3.7E-05	6.6E-05	+2.9E-05	4.4E-05	7.3E-05	+2.9E-05
LERF (per year)	3.3E-06	3.3E-06	--	3.3E-06	3.3E-06	--

The results above show that the combined affects of the changes to common cause group modeling result in only insignificant changes to LERF numeric results. In addition, a comparison of the significant cutsets for LERF indicated only minor changes in the contributions of each event to this risk metric.

For the CDF risk metric, however, changes to the common cause group modeling caused significant changes to the results. As discussed above, the primary cause of the increase in CDF is that the original base models did not include CCF of the air compressors as a failure mode for the loss of instrument air initiating event. The increase in CDF above results almost entirely from additional failures that represent loss of IA initiating events. The effect of these additional cutsets on the comparisons used for the EPU evaluations is addressed in the following sections.

Next, the effect of not considering risk reduction measures on the post-EPU model was calculated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR	Post-EPU with AFW Mods	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR
CDF (per year)	5.6E-05	8.5E-05	+2.9E-05	6.4E-05	9.3E-05	+2.9E-05
LERF (per year)	4.5E-06	4.5E-06	--	4.5E-06	4.5E-06	--

The results above show that the combined effects of the changes common cause group modeling result in only insignificant changes to LERF numeric results.

For the CDF risk metric, however, changes to the common cause group modeling cause significant changes to the results. These changes occur primarily because the original base models did not include common cause failure of the air compressors as a failure mode for the loss of instrument air initiating event. The increase in CDF above results almost entirely from additional failures that represent loss of IA initiating events. The additional cutsets for this case were compared to the additional cutsets generated for the pre-EPU base case described above. This comparison showed that the additional cutsets generated by changing the common cause grouping for air compressors were identical for the pre-EPU and post-EPU models. Since the primary reason for the increase in CDF shown above is due to changes in air compressor common cause modeling, the combined affect of changing the common cause grouping, while changing the value of the CDF risk metric, has no significant effect on the change in risk resulting from the EPU.

Finally, the effect of risk reduction strategies on the post-EPU model was evaluated. The results are shown below:

	Unit 1			Unit 2		
	Post-EPU with AFW and Risk-Reduction Mods	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR	Post-EPU with AFW and Risk-Reduction Mods	Revised SW, EDG, & IA CCF Modeling	Change from Results in LAR
CDF (per year)	3.5E-05	3.7E-05	+2E-06	3.7E-05	3.9E-05	+2E-06
LERF (per year)	2.2E-06	2.2E-06	--	2.2E-06	2.2E-06	--

The results above show that the changes to common cause group modeling result in only insignificant changes to LERF numeric results. In addition, a comparison of the significant cutsets for LERF indicated only minor changes in the contributions of each event to this risk metric.

Only very small changes to the CDF numeric results are seen and a review of the final cutsets shows only minor changes in the overall contributions for each event.

As a final comparison, the pre-EPU base LAR model results are compared to the post-EPU results with AFW and risk reduction modifications included along with the changes in SW, EDG and IA CCF modeling discussed above:

	Unit 1			Unit 2		
	Base LAR Model	Post-EPU with AFW and Risk-Reduction Mods with Revised SW, EDG & IA CCF Modeling	Change from Results in LAR	Base LAR Model	Post-EPU with AFW and Risk-Reduction Mods with Revised SW, EDG & IA CCF Modeling	Change from Results in LAR
CDF (per year)	3.7E-05	3.7E-05	--	4.4E-05	3.9E-05	-5.0E-06
LERF (per year)	3.3E-06	2.2E-06	-1.1E-06	3.3E-06	2.2E-06	-1.1E-06

The risk values from the pre-EPU base model compared to the risk values with the AFW and risk reduction strategies planned for the EPU project will result in an overall reduction in risk for Unit 2 and no increase for Unit 1, even considering the uncertainty of CCFs. Therefore, changing the common cause grouping has no significant impact on the change in risk resulting from the EPU.

APLA-5

Increased heat associated with EPU is expected to increase steam flow during normal operations and after a plant trip. Increase steam flow from the steam generators can result in unexpected flow-induced vibration. Please explain how the EPU affects flow-induced vibration in PBNP steam generators. Also, please compare the recovery time available for steam generator overfills scenarios for pre-EPU and post-EPU.

NextEra Response

For a power uprate evaluation, Westinghouse performed flow induced vibration (FIV) assessments on two areas of the steam generator (SG); potential wear of the tubes in the SG tube bundle, and potential weld cracking of the SG secondary separators or dryers.

For FIV-related wear of the SG tubes, thermal-hydraulic properties of the secondary side of the steam generator were evaluated for the effects on tube vibration mechanisms and associated tube wear and fatigue. The evaluation concluded that the EPU effects on tube wear and fatigue are acceptable. Details of the evaluations and results are provided in LAR 261, Attachment 5, Section 2.2.2.5.7, Steam Generator Tube Wear.

For potential FIV-related cracking of the SG secondary separators, historical data of operating pressurized water reactor (PWR) SGs was reviewed, geometrical differences between boiling water reactor (BWR) dryers and PWR dryers were compared, and a vibration analysis on the PBNP SG dryers was performed. There are no predicted vibration issues identified for Units 1 and 2 SG steam dryer bank assemblies at EPU conditions. Details of the evaluations and results are provided in LAR 261, Attachment 5, Section 2.2.2.5.12, Regulatory Guide 1.20 Evaluation – Vibration Assessment Program for Reactor Internals.

The PBNP PRA uses a 44-minute window as the available time to prevent overfill following a steam generator tube rupture (SGTR). This time is based on final safety analysis report (FSAR) analyses. For SGTR events, the FSAR accident timing pre and post-EPU were determined to be the same so no change in the overfill scenarios was needed for the post-EPU PRA models.

APLA-6

Due to the EPU, some pipe segments may exceed industry standards for flow velocity (e.g., turbine building feedline, turbine building extraction steam). How does PBNP address pipe segments that exceed flow velocity post-EPU?

NextEra Response

Flow velocity is addressed in the following sections in LAR 261, Attachment 5:

- Section 2.1.8, Flow Accelerated Corrosion
- Section 2.5.5.1, Main Steam
- Section 2.5.5.4, Condensate and Feedwater

The piping analysis is done based on the EPU conditions and acceptance criteria are based on existing code allowable limits. Increased flow velocity is captured in the flow accelerated corrosion (FAC) program and monitored based on existing acceptance criteria. In addition as part of the EPU power ascension plan, vibration monitoring is performed to identify vibration and evaluate impact. The monitoring and evaluation for vibration is performed in accordance with ASME OM-S/G-2003. No increase in frequency of failure is expected.

The initiating event frequency values for steam line and feed line breaks used for the PBNP PRA are based on NUREG/CR-5750. While there could be some change expected in the frequency for secondary line breaks outside of containment for post-EPU conditions, there is no basis for postulating a change. Nonetheless, the EPU PRA analyses assumed that both steam line and feed line break frequency would increase by 20% for post-EPU conditions.

APLA-7

Significant EPU-related modifications are proposed for both units of PBNP, such as replacement of Main Feedwater Pumps, Feedwater Heaters, and Main Transformers. Briefly describe existing or future programs that will sufficiently address potential break-in failures and reliability of new equipment. Please provide a sensitivity analysis for the break-in period.

NextEra Response

The modification packages associated with major modifications, such as main feedwater pumps, feedwater heaters and main transformers provide the post modification testing to demonstrate the new equipment meets acceptance criteria and is OPERABLE. During power ascension to the EPU power level, system and component monitoring is performed to ensure the expected values are being met. Following the implementation of EPU, revisions to existing plant surveillance and testing programs will reflect new equipment and will provide required performance monitoring and testing. Equipment condition monitoring will continue to be provided by plant instrumentation, with alarms to provide plant personnel timely notification of equipment problems. New or existing equipment within the scope of Maintenance Rule will also have performance monitored by the Maintenance Rule program.

As described in the LAR 261, Attachment 5, Section 2.13, Risk Evaluation, no planned changes were identified that would have a direct impact on transient frequency. As described in LAR 261, Attachment 5, Section 2.12.1.2.3, during power ascension to the EPU power level, system and component monitoring is performed to ensure the expected values are being met. However, the frequency values for transients, with and without feedwater available, were each increased by 20%. The post-EPU risk values presented in LAR 261 include this increase in frequency. It is felt that this increase will bound any increase in initiating event frequency that would be expected should any period of break-in failures occur. Therefore, no additional sensitivity analysis is required for the break in period.

APLA-8

Due to increased decay heat during EPU operations more pressure operated relief valves (PORV) maybe required for successful feed and bleed post-EPU. Please provide a basis for determining success criteria for feed-and-bleed with and without charging availability post-EPU.

NextEra Response

The PBNP PRA models do not credit use of the positive displacement charging pumps for feed and bleed cooling. The success criteria for feed and bleed cooling were determined using the MAAP computer code. For both the pre-EPU and post-EPU conditions, the success criteria were analyzed using a representative analysis. The same conditions were evaluated for both pre-EPU and post-EPU and success was shown with one safety injection pump injecting and one pressurizer pressure operated relief valves (PORV) opening. The difference between pre-EPU and post-EPU conditions is in the time that feed and bleed cooling must be initiated. The result of the MAAP code analyses show that for pre-EPU, the conditions to initiate feed and bleed cooling were reached in 56 minutes with core damage occurring in two hours, if feed and bleed is not initiated. For post-EPU conditions, the MAAP results show that conditions to begin feed and bleed cooling were reached in 35 minutes with core damage occurring in 98 minutes, if feed and bleed cooling is not initiated.

APLA-9

Pressurizer level may have larger variation due to the power uprate. Since it is possible that the higher water level could lead to increased PORV challenges and less pressurizer steam volume to react to pressure changes, please address the risk impact of larger variations in pressurizer level for PBNP post-EPU.

NextEra Response

A challenge to the pressurizer PORV followed by failure to close is assumed in the PBNP PRA to result in a small LOCA. The PBNP PRA estimates the probability that a PORV or safety relief valve (SRV) opens based on the number of transients that have actually occurred at the plant and no events of an inadvertent opening of a PORV or SRV. An evaluation of the transient response was performed using the MAAP computer code. These evaluations show that no appreciable change in the post-trip pressure response is expected, although the analyses did show a more rapid pressure response for post-EPU conditions. These results were for plant response following a loss of offsite power when pressurizer spray valves and reactor coolant pumps (RCPs) would be unavailable. Availability of pressurizer sprays would be expected to mitigate any post-trip pressure increases. Even for loss of offsite power events, the MAAP runs showed only a change in timing for pressure changes, but no overall change in pressure response. non-loss of coolant accident (LOCA) design basis accident analyses show that a loss of load event could result in a pressure transient that could challenge pressurizer PORVs or SRVs. Best-estimate analyses based on the design basis models showed no significant change in post-trip reactor coolant system (RCS) pressure response, thereby confirming the results produced by the MAAP computer code.

Even though the plant response models showed no significant change in pressure response, the frequency of small LOCAs caused by PORVs was increased. The frequency of a small LOCA caused by a transient-induced pressure excursion was calculated in the initiating events analysis to be 2.2E-05 per year. This frequency is based on the number of PORVs (2), the frequency of transients (0.46 events per year), the probability of challenging a PORV given a transient (8.1E-03), and the probability that a PORV fails to reseat (3E-03). Of these parameters, the frequency of transients and the probability of challenging a PORV could be affected by the EPU. Although no specific causes for an increase were identified, the EPU PRA analysis assumed that the transient frequency will increase by 20%. Although the best estimate evaluations show no significant change in post-trip pressure response, the design basis analyses show a significant change in post-trip pressure response. Because the design basis analyses show that a loss of load event could result in a pressure transient that could challenge pressurizer PORVs or SRVs, a significant increase in probability of PORV challenge was used to provide a bounding estimate of any risk change. This EPU PRA analyses assumed that the probability of challenging a PORV will increase by 300%. These changes would cause the frequency of a transient-induced small LOCA to increase to 7.9E-05 per year. Therefore, the increase in small LOCA frequency would be:

(7.9E-05 per year) - (2.2E-05 per year) = 5.7E-05 per year.

This is added to the base value for small LOCA of 3.2E-03 per year to give a revised estimate for post-EPU small LOCA frequency of:

(3.2E-03 per year) + (5.7E-05 per year) = 3.3E-03 per year.

In addition to the challenges addressed above, failure of flow is assumed from both the turbine-driven AFW (TDAFW) pump and motor driven AFW (MDAFW) pump to both steam generators immediately following a transient without power conversion system (T2), loss of IA (TIA), loss of SW (TSW), loss of bus D-01 (TD1), or loss of bus D-02 (TD2) event would result in overfill of the pressurizer and lifting a PORV. No credit was taken for operator action to align the standby emergency feedwater pumps to prevent pressurizer overfill because the time required to align the pumps may be too long to prevent overfill. The standby emergency feedwater pumps are credited for decay heat removal. Further, if a PORV is assumed to lift due to a complete loss of AFW flow, water is assumed to pass through the valve, and the valve is assumed to stick open, thereby leading to a small LOCA.

APLA-10

The PBNP EPU submittal states that over 100 unique post-initiator operator actions were developed for the PBNP PRA and only those operator actions evaluated as having significant impact to EPU were analyzed. Please explain the criteria used to determine those operator actions significant to EPU. Based on previous submittals, the staff has accepted the following minimum criteria for operator action screening:

- *F-V (with respect to core damage frequency (CDF) and large early release frequency (LERF)) importance measure ≥ 5E-3*
- *RAW (with respect to CDF and LERF) importance measure ≥ 2.0*
- *Time critical (≤ 30 minutes available) action*

Please analyze all post-initiator operator actions which fall within the screening criteria listed above or provide basis for the screening criteria chosen for EPU review.

NextEra Response

All post initiator (Type C) operator actions included in the PBNP PRA were evaluated for potential effects resulting from the EPU. For each operator action, the following items were considered:

1. Is the operator action independent of reactor power?

2. Has the timing available to perform the operator action changed significantly post-EPU?

3. Is the operator action obviously insignificantly affected by the EPU?

Where the time available to perform the action modeled in the PRA was affected by the EPU, the event was evaluated using the revised timing and the revised human error probability (HEP) included in the models. Some operator actions would be considered independent of reactor power. One example is the operator action to isolate a leak in the component cooling water (CCW) system. The timing for this event is based on the volume in the CCW system, which is independent of reactor power. HEPs such as this were not changed in the post-EPU PRA model.

Based on this evaluation, approximately one-third of the operator actions in the pre-EPU PRA model were determined to be impacted by the EPU due to the increased power level and/or reduced timing. Because all operator actions which could be affected by changes in reactor power or other parameters affected by the EPU were analyzed, no additional analyses of operator actions were performed.

APLA-11

Please explain why installation of a self-cooled air compressor and backup air supply for the Pressurizer Auxiliary Spray Valve contributes to differing changes in risk metrics between Unit 1 and Unit 2.

NextEra Response

For the pre-EPU models, the CDF for Unit 1 is 3.7E-05 per year while for Unit 2, the CDF is 4.4E-05 per year. The difference between the two risk measures is caused by physical differences between the two units, primarily the power supply for the motor-driven fire pump. The power supply for the motor-driven fire pump is 480 V AC bus 1B03. Unavailability of that bus, primarily during Unit 1 outages, renders the pump unavailable as a backup water source for AFW pump suction and cooling, thereby resulting in a stronger dependency of the Unit 2 model on SW.

For the post-EPU models, the installation of a self-cooled air compressor, i.e., a compressor not requiring SW cooling, reduces the dependence of each unit on SW. Because Unit 2 had a stronger dependence on SW, the additional air compressor shows a larger reduction in risk. As a result, the risk metrics for Unit 1 and Unit 2 are more symmetric with the addition of a self-cooled air compressor. This can be seen in the CDF values for the case of post-EPU with AFW modification unit and the addition of a self-cooled air compressor, which are 4.1E-05 and 4.2E-05 per year, for Unit 1 and Unit 2, respectively.

Via LAR 261, Attachment 4, Item 13, NextEra made a Regulatory Commitment to provide a backup compressed gas supply for the pressurizer auxiliary spray valve inside containment for each unit prior to operation at EPU conditions. Upon further review, NextEra has determined that the pressurizer auxiliary spray valve for each unit will perform the desired function to open as it is currently configured and that a modification is not required. Modifications installed in the 2002 time frame for each unit now allow these air-operated valves to open on approximately 250 psi differential pressure across the valve. The positive displacement charging pumps are capable of developing this differential pressure and opening the valve without IA. Consequently, the modification to provide a backup compressed gas supply for the valve(s) is not necessary.

An emergency operating procedure (EOP) change will be made to provide Operations personnel guidance to open the pressurizer auxiliary spray valve using differential pressure across the valve. The procedure change for opening the pressurizer auxiliary spray valve using differential pressure across the valve provides a symmetric risk reduction for each unit as shown below.

	Unit 1			Unit 2		
	Base LAR Model	Post-EPU with AFW Mods and Pressurizer Auxiliary Spray Valve Procedure Changes	Change in Results from LAR	Base LAR Model	Post-EPU with AFW Mods and Pressurizer Auxiliary Spray Valve Procedure Changes	Change in Results from LAR
CDF (per year)	3.7E-05	5.4E-05	1.7E-05	4.4E-05	6.1E-05	1.7E-05
LERF (per year)	3.3E-06	2.2E-06	-1.1E-06	3.3E-06	2.2E-06	-1.1E-06

The procedure change for opening the auxiliary spray valve by use of differential pressure across the valve ensures a redundant and diverse means to depressurize the RCS following a SGTR. Because SGTR events contribute the same total value to CDF and LERF, the numerical risk reduction for this proposed plant change is the same for each unit. The asymmetry for the absolute risk values shown above are caused by the effects described above for the motor-driven fire pump power supply. As with all EOP changes, operator training will be provided.

APLA-12

EPU Licensing Report Section 2.13.1-43 provides requantification analysis of human error probability. Please describe any new operator actions developed due to the EPU that could impact the PRA and describe the methodology utilized to determine the error probability associated with the new actions.

NextEra Response

Only two new operator actions were included in the post-EPU PRA models. These actions are operator action to align the standby emergency feedwater (SBEFW) pumps to provide makeup to the steam generators should the main feedwater and AFW systems fail and operator action to colose a pressurizer PORV block valve should the PORV open and fail to reclose.

The first action modeled operator failure in two parts, the cognitive failure to recognize the loss of secondary heat removal and the execution failure to align the standby emergency feedwater pumps. The cognitive failure to recognize the loss of secondary cooling was already included in the PRA models and is common to the actions to provide feed and bleed cooling and other actions to restore secondary cooling. The cognitive failure had been included with the execution failure to provide the HEPs used in the PRA models. EPU created a new basic event for the cognitive failure only which used the previously calculated cognitive failure rate. Execution failures to align the standby emergency feedwater pumps were modeled using a screening value of 0.05. This screening value is considered conservative for the execution failures since only a few valve manipulations would be required and the value is consistent with other simple execution failures modeled in the PBNP PRA. A detailed evaluation of the HEP was not performed because the procedures to use the standby emergency feedwater pumps are not yet developed and the new AFW pumps are not yet installed. Dependency between failure to start the SBEFW system and failure to initiate feed and bleed cooling was also considered. As discussed above, a complete dependency of the cognitive failure (i.e. failure to recognize the loss of secondary heat sink) was assumed and modeled by using a single, common basic event for both the SBEFW and feed and bleed fault tree models. For dependence between execution failures, a screening value of 0.1 was used.

Failure of operator action to close the block valve for a stuck-open pressurizer PORV was modeled using a screening value of 0.05. This screening value is also considered conservative for the execution failures since only a few valve manipulations would be required and the value is consistent with other simple execution failures modeled in the PBNP PRA.

APLA-13

The staff requests responses for the following information on Low Power and Shutdown operations:

a. Explain how the EPU affects the scheduling of outage activities.

b. Provide additional information regarding the reliability and availability of equipment used for shutdown conditions.

c. Explain how the EPU affects the availability of equipment or instrumentation used for contingency plans.

d. Explain how the EPU affects the ability of the operator to close containment.

NextEra Response

a. Installation of major modifications required for EPU is currently scheduled to be completed during the Unit 2 spring 2011 and Unit 1 fall 2011 outages. The duration for these two refueling outages is currently planned for approximately 68 days each. While the scope and duration of the EPU implementation outages will surpass a typical refueling outage, the scheduling of outage activities for the EPU implementation will use existing processes and procedures for control of work and risk management. After the refueling outages to install the EPU modifications, the EPU will have minimal affect on scheduling of future outages.

   The PBNP shutdown safety review and safety assessment procedure is used to implement applicable risk management requirements, to provide background information for risk management, and to provide justification for the shutdown safety assessment process. The shutdown safety assessment is a management tool to assess the risk to plant nuclear safety associated with the initial refueling outage plan and to evaluate the level of plant nuclear safety associated with changes to that plan. The initial refueling shutdown safety review and the shutdown safety assessment process includes all steps from the initial safety review of the outage schedule through subsequent reviews and safety assessments of the schedule as the outage progresses. The procedure details the background for this process and describes the methods and criteria to be used, including the required reviews.

Shutdown safety assessments are performed deterministically following the guidelines in Nuclear Management and Resource Council (NUMARC) 91-06, Guidelines for Industry Actions to Assess Shutdown Management.

b. The majority of modifications being implemented for EPU involve secondary side, power generation support components not typically needed for shutdown safety or risk management. However, there are some EPU modifications and some equipment additions affecting systems and components that are used during shutdown operations or are considered in shutdown safety assessments. These include the new AFW pumps and associated AFW system equipment, the new main generator breaker, replacement main step-up transformers, changes to plant instrumentation, changes to the electrical distribution system, and installation of an air compressor which does not require SW to operate. Following installation or modification, the associated systems and components are expected to experience increased reliability and availability.

   During the EPU implementation outages, modifications to systems and installation of new equipment will be controlled as described above to ensure risk management requirements are satisfied. The PBNP modification process ensures that the modifications and new equipment are incorporated into the shutdown safety assessment procedure for consideration in future outages.

c. During the EPU implementation outage, some equipment considered for use in contingency plans will be unavailable due to the installation of modifications. The PBNP shutdown safety review and safety assessment process will consider work on plant equipment and ensure any equipment required for use in contingency plans will be available, if it is needed for outage conditions. Following implementation of the EPU modifications, new and modified equipment will be considered during development of contingency plans in accordance with guidance provided in the safety review and safety assessment process.

d. As a result of the EPU, the decay heat at a given time after shutdown increases, approximately proportional to the change in the power level due to the EPU. This, in turn, reduces the time to boiling and the time to core uncovery following a postulated loss of residual heat removal (RHR) cooling. Analyses have been performed to determine the time to reach 200°F, the time to reach saturation, and makeup and boil-off rates for a loss of RHR at mid-loop conditions. The results for the analyses are provided in LAR 261, Attachment 5, Table 2.8.7.1-3, Loss of RHR at Mid-loop (EPU) Results. The increase in decay heat for EPU will potentially result in a reduced required time to perform containment closure. Plant shutdown emergency procedures contain time to boil curves. These curves will be updated for EPU conditions.

   The plant procedure for containment closure provides guidance for containment closure and a listing of containment penetrations which must be isolated to establish containment closure. This procedure also provides contingency actions to isolate degraded penetrations and containment hatches that are required for containment closure.

   The PBNP shutdown safety review and safety assessment process provides guidance for ensuring containment closure can be completed within the required time, as part of outage risk assessment.

   For EPU implementation, work on some containment penetrations may be required to support electrical or mechanical modifications to plant equipment and systems. The PBNP shutdown safety review and safety assessment process will be used to ensure risk management requirements are satisfied during the work. No permanent changes to containment penetrations or containment airlocks are anticipated as a result of implementation of EPU modifications.

Following implementation of EPU, while the time to perform containment closure will be reduced in some instances, no changes to the containment penetrations or hatches are anticipated. Additionally, procedures are in place to ensure that containment closure can be achieved in the required time prior to initiating any outage activities that would affect containment.

APLA-14

The majority of risk impact due to EPU implementation typically relates to human reliability. The Nuclear Regulatory Commission (NRC) staff finds considerable inconsistencies between the PBNP human reliability risk evaluation and prior EPU submittals from other utilities. The following questions address the analyses conducted by PBNP in regard to human reliability:

a *The licensee states that over 100 unique post-initiator operator actions were developed for the PBNP PRA and the vast majority of these events are not impacted by the EPU. 34 human error probabilities (HEP) are identified as having an impact on the EPU. Many of the identified HEPs were substantially increased by 400 percent to 1400 percent. Increases in HEP by this amount are not typically seen by NRC staff in other plant EPU submittals. Please explain why PBNP PRA has uncharacteristically high increases in HEP values for an EPU application. Are the increases in HEP values attributable entirely to EPU or has there been a change in methodology between pre-and post-EPU. If different methodologies were used for pre-and post-EPU, please provide a delta change in HEP values using the same methodology.*

b. *For Feed and Bleed action, HEP-IA-FO-04748 Operator fails to Reopen 3047 or 3048, the system time window was reduced from 56 minutes to 35 minutes and high dependency was assigned for recovery actions. This change results in HEP increase of 35 percent for the EPU application. Feed and Bleed action, HEP-MFW-CSPH1-06, also reduces time from 56 minutes to 35 minutes and high dependency was assigned for recovery actions, however; HEP for this action increase by 1370 percent for the EPU. Please explain why operator actions developed based on the time to reach feed and bleed initiation criteria after a transient event vary by two orders of magnitude.*

c. *Dependency levels were changed for the majority of HEPs from medium to high. Please explain criteria used to determine dependency levels for HEPs pre-and post-EPU.*

d. *Given that the HEPs are the primary change in risk impact for EPU, please provide more realistic HEP values and their pre-and post-EPU results.*

NextEra Response

a. No change in the methodology used to quantify HEPs for the post-EPU PRA model occurred. All HEPs requantified for the post-EPU model were quantified using the same methodology used in the base, or pre-EPU, model. The method used to quantify each HEP is identified in LAR 261 HEPs were calculated using the Electric Power Research Institute

(EPRI) Human Reliability Analysis (HRA) calculator software using the same methods as for the pre-EPU models.

As described in the LAR, many of the operator actions included in the PBNP PRA model and impacted by the EPU are based on the time to initiate feed and bleed cooling. The time window prior to the need to initiate feed and bleed cooling is reduced for post-EPU conditions to 35 minutes from 56 minutes. Changing the system time window to 35 minutes from 56 minutes as input to the EPRI HRA calculator software results in the changes described in the LAR. Other operator actions showing significant increases in the associated HEPs are based on the time to core damage following an RCP seal LOCA and a station blackout (SBO). The system time window for these events has decreased from 120 minutes to 98 minutes. As described previously for feed and bleed cooling, this reduction in time available was changed in the EPRI HRA calculator software with the resulting HEP values.

b. The actions modeled by event HEP-IA-FO-04748 are relatively simple, involving only one step in a procedure. Because the action is simple, there is the chance to recover from an error executing the actions modeled through procedurally-directed checks. Since there is a 15-minute window available to recover the simple action, the impact of reduced timing on the event to restore instrument air to containment is small.

   The actions modeled by event HEP-MFW-CSPH1-06 are operator actions to restore main feedwater after it has been isolated by a safety injection (SI) signal. These actions are more complex than the simple action to restore IA to containment. Restoration of main feedwater includes seven separate procedural steps with 15 distinct actions. There is one procedurally directed recovery at the end of all the modeled steps, "verify flow to SG," which would direct the operators to reattempt the actions. However, the time required to perform all 15 actions limits the ability to recover a failure of any one of the actions. Therefore, the failure probability for this event increases significantly compared to the simple action to restore IA to containment.

c. The HEPs for operator actions modeled in the PBNP PRA were quantified using the EPRI HRA calculator software and the modeling method, e.g., CBDTM/THERP, delineated in the LAR. The minimum dependency level used for recovery for both pre- and post-EPU conditions is identified by the software using the timing information entered. In some instances, the pre-EPU analyses used a higher dependency level than was suggested by the software. For the post-EPU analyses, the dependency levels developed by the software were used consistent with the dependency levels used in the pre-EPU evaluations. That is, if the pre-EPU evaluations used the dependency levels determined directly by the software, then the post-EPU evaluations used the dependency levels determined by the software. If the pre-EPU evaluations increased the dependency levels above that determined by the software, then the post-EPU evaluations similarly increased the dependency levels by the same level.

d. To assess the impact of the HRA on the EPU, each operator action that increased by more than 400% and that contributes more than 0.5% to CDF or LERF (for the post-EPU model considering risk reduction modifications) was identified. The analysis of each of the identified events was then reviewed to identify any significant conservatism. When significant conservatism was identified, the HEP was reanalyzed to reduce the conservatism.

Post-EPU, HEPs for the following basic events were increased by greater than 400%:

- 125-HEP-1B32D302
- 125-HEP-1B49D301
- 125-HEP-2B39D301
- 125-HEP-2B42D302
- 125-HEP-B81-D302
- 125-HEP--D04-D28
- 125-HEP--D04-D40
- 125-HEP-D05--D01
- 125-HEP-D06--D02
- 125-HEP-D105-D03
- 125-HEP-D106-D04
- 125-HEP-D14-D40
- 125-HEP-D28-D40
- 125-HEP-D305-D01
- 125-HEP-D305-D02
- 125-HEP-D305-D03
- 125-HEP-D305-D04
- 125-HEP--D49-D51
- 125-HEP--D49-D52
- 125-HEP--D49-D53
- 125-HEP--D50-D51
- 125-HEP--D50-D52
- 125-HEP--D50-D53
- 125-HEP-EOP10-08
- HEP-MFW-CSPH1-06

Of these, the following HEPs have been determined to contribute more than 0.5% to either unit's CDF or LERF for the post-EPU model considering the risk reduction strategies proposed for the EPU:

- 125-HEP-1B49D301
- 125-HEP-D28-D40
- 125-HEP-D305-D01
- 125-HEP-D305-D02
- 125-HEP-D305-D04
- 125-HEP-EOP10-08
- HEP-MFW-CSPH1-06

The analysis of actions represented by each of the basic events listed above is evaluated to identify significant conservatism below.

<u>125-HEP-1B49D301, Operator Failure To Align 1B49 To D301</u>

The HEP for this action is developed based on the time to core damage following a station blackout with a 480 gpm per pump RCP seal LOCA, loss of all AFW flow, and no RCS cooldown. For the EPU, MAAP analyses used to support the HRA were updated. The revised timing for this event shows a time window of 98 minutes from initiating event to core damage, the time used in the initial development of this event.

Key assumptions used in the original development of the HEP for this event are:

- The maximum size RCP seal LOCA occurs on each reactor coolant pump (480 gpm per pump or 960 gpm total)
- The RCP seal failure occurs 10 minutes after the initiation of the event
- All AC power is lost for 60 minutes and no preparations are taken for recovery prior to that time
- No action is taken to begin RCS cooldown
- High stress for execution actions

The effect of the first item above is to maximize the coolant loss from the RCS, thereby reducing the time available to restore DC power. The MAAP analyses performed for the EPU show that reducing the break flow extends the time to core damage. Removing conservatism by assuming a smaller RCP seal LOCA would provide additional time to recover DC power. The second item also maximizes the coolant loss thus reducing the time available for recovery. It is expected that RCP seal failure would be delayed for at least 13 minutes based on Westinghouse evaluations of RCP seal failure. Eliminating the conservative assumption of an immediate RCP seal LOCA provides additional time to recover DC power. Conservatism in the last two items also minimizes the time available to perform the actions represented by this event. Preparations or anticipation of the need to recover DC power or an RCS cooldown would provide additional margin to core damage thereby allowing additional time for DC power recovery.

The primary reason for the increase in failure probability for this event in the post-EPU model is the reduction in time available for recovery of failed steps in the execution. The base case (pre-EPU) analysis used a medium dependence for recovery of execution steps. This dependency level is the recommended dependency level that is obtained by following the CBDTM/THERP HRA technique and using a total time available of 120 minutes with a 60-minute delay and a 30-minute execution time requirement. Reducing the total time available to 98 minutes while holding the other two times constant results in a recommended high dependency for recovery of failed execution steps. Changing the dependency level from medium to high in the post-EPU model causes all of the increase in the HEP value.

Reducing conservatism in the size of the RCP seal LOCA and the timing of the RCP seal failure would be expected to extend the time available before core damage would occur. The MAAP analyses performed for the EPU show that the time to core damage is extended to 105 minutes, assuming that a 21 gpm per RCP seal failure occurs at the initiation of the event. Based on the post-EPU MAAP evaluations, the time to core damage shows only a minor dependency on the RCP seal LOCA size and is more dependent on the availability of AFW for secondary cooling. Even using 105-minute window for recovery of DC power, the CBDTM/THERP methodology would still result in a recommended high dependency for recovery of execution events. Thus, it is not expected that changes to the timing analysis or stress level would affect the post-EPU HEP calculations.

The other factor affecting the HEP value for this event is the assumed stress level for execution. The post-EPU values presented in the LAR assumed a high stress level for execution. However, the actions represented by this basic event will occur after successful recovery of AC power. This success would be expected to result in lower stress levels since the plant would be responding as expected and the operators would now have additional plant systems available.

Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-1B49D301	Operator Failure To Align 1B49 To D301	1.40E-02	7.40E-02	3.40E-02

125-HEP-D28-D40 Failure of Operator To Align D-28 To Bus D-40

The HEP development for this action is identical to the development of 125-HEP-1B49D301 described above. Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-D28-D40	Failure Of Operator To Align D-28 To Bus D-40	1.40E-02	7.40E-02	3.40E-02

125-HEP-D305-D01 Operator Fails To Align D-305 To Bus D-01

The HEP development for this action is identical to the development of 125-HEP-1B49D301 described above. Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-D305-D01	Operator Fails To Align D-305 To Bus D-01	1.40E-02	7.40E-02	3.40E-02

125-HEP-D305-D02 Operator Fails To Align D-305 To Bus D-02

The HEP development for this action is identical to the development of 125-HEP-1B49D301 described above. Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-D305-D02	Operator Fails To Align D-305 To Bus D-02	1.40E-02	7.40E-02	3.40E-02

125-HEP-D305-D04, Operator Fails To Align D-305 To Bus D-04

The HEP development for this action is identical to the development of 125-HEP-1B49D301 described above. Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-D305-D04	Operator Fails To Align D-305 To Bus D-04	1.40E-02	7.40E-02	3.40E-02

125-HEP-EOP10-08 Failure to Restore 125V DC After Loss of Voltage and Recovery of AC Power

The HEP development for this action is similar to the development of 125-HEP-1B49D301 described above. That is, the time available to perform the action is the same and the basis for selecting dependence and stress level are the same. The difference between 125-HEP-1B49D301 and this event is in the number of actions that must be performed. Since all other factors are the same as in the calculation for 125-HEP-1B49D301, it is appropriate to reduce the execution stress level. Changing the execution stress level from high to medium in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
125-HEP-EOP10-08	Failure To Restore 125V DC After Loss Of Voltage And Recovery Of AC Power	2.10E-03	1.40E-02	5.60E-03

HEP-MFW-CSPH1-06, Failure to Restore Main Feedwater to SG after SI Signal has Occurred

The HEP for this action is developed based on the time to SG dryout following a safety injection signal that isolates main feedwater and a loss of all AFW. For the EPU, MAAP analyses used to support the HRA were updated. The revised timing for this event shows a time window of 35 minutes from initiating event to SG dryout, the time used in the initial development of this event.

One key assumption used in the initial development of this event was that the stress level should be increased one level above the recommend level based on the CBDTM/THERP methodology. This increase was made to be consistent with a similar increase made in the pre-EPU model development. In the pre-EPU model development, the execution dependence level was increased from low to medium. For the post-EPU model, the recommended dependence level is high. In the original analysis, this dependence level was increased to complete. However, for post-EPU conditions, complete dependence for execution would be overly conservative since the operators do have the opportunity to recover failed steps. Therefore, this event was reevaluated using the recommended dependence level.

Changing the execution dependence level from complete to high in the HRA calculator, the HEP for this event is recalculated with the results shown below.

Basic Event	Event Description	Pre-EPU Value	Original LAR Value	Updated Post-EPU Value
HEP-MFW-CSPH1-06	Failure to Restore Main Feedwater to SG after SI Signal has Occurred	1.70E-02	2.50E-01	1.30E-01

The effect of the revised HEPs, shown above, on the post-EPU PRA models was evaluated. First, the impact on the post-EPU model with AFW Mods is calculated. The impact on the post-EPU model with AFW Mods and risk reduction strategies is then evaluated.

The results for the post-EPU model with AFW modifications are shown below. These results are contrasted with the results presented in the LAR for each unit.

	Unit 1			Unit 2		
	Post-EPU with AFW Mods	Post-EPU with AFW Mods and Revised HEPs Shown Above	Change from Results in LAR	Post-EPU with AFW Mods	Post-EPU with AFW Mods and Revised HEPs Shown Above	Change from Results in LAR
CDF (per year)	5.6E-05	4.8E-05	-8E-06	6.4E-05	5.4E-05	-1E-05
LERF (per year)	4.5E-06	4.5E-06	--	4.5E-06	4.5E-06	--

The results above show that the removal of conservatism used to develop the HEP values used in the quantification results presented in the LAR would result in a significant reduction in the overall increase in CDF and only insignificant changes in the increase in LERF.

The HEP changes described previously were included in the EPU model developed to evaluate the impact of potential risk mitigation strategies. The results are shown below and contrasted with the results presented in the LAR for each unit.

	Unit 1			Unit 2		
	Post-EPU with AFW and Risk-Reduction Mods	Post-EPU with AFW and Risk-Reduction Mods Using Revised HEPs	Change from Results in LAR	Post-EPU with AFW and Risk-Reduction Mods	Post-EPU with AFW and Risk-Reduction Mods Using Revised HEPs	Change from Results in LAR
CDF (per year)	3.5E-05	2.6E-05	-9E-06	3.7E-05	2.7E-05	-1E-05
LERF (per year)	2.2E-06	2.2E-06	--	2.2E-06	2.2E-06	--

The results above show that the removal of conservatism used to develop the HEP values used in the quantification results presented in the LAR would result in a significant reduction in the CDF and an insignificant change in LERF. However, a more significant insight from the above results is that, regardless of the risk increase that results from changing the likelihood of operator error, the proposed risk mitigation strategies being implemented for the EPU result in a net risk reduction overall. Therefore, it is concluded that the (HRA) techniques, assumptions, and models used to evaluate post-EPU conditions are not a significant issue when considered in conjunction with the risk reduction strategies being implemented.

References

(1) NRC letter to NextEra Energy Point Beach, LLC, dated April 22, 2010, Point Beach Nuclear Plant, Units 1 and 2 – Request for Additional Information from Probabilistic Risk Assessment Licensing Branch Re: Extended Power Uprate (TAC NOS. ME1044 and ME1045) (ML101040946)

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

(3) WEPCO letter to NRC, dated June 30, 1993, Summary Report on Individual Plant Examination for Severed Accident Vulnerabilities Point Beach Nuclear Plant, Units 1 and 2

(4) NRC letter to WEPCO, dated January 26, 1995, Review of Individual Plant Examination Submittal for Internal Events – Point Beach Nuclear Plant, Units 1 and 2 (TAC NOS. M74452 and M74453)