Florida Power & Light Company, 6501 S. Ocean Drive, Jensen Beach, FL 34957

FPL

August 25, 2011

L-2011-343
10 CFR 50.90

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

Re: St. Lucie Plant Unit 2
Docket No. 50-389
Renewed Facility Operating License No. NPF-16

Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request

References:

(1) R. L. Anderson (FPL) to U.S. Nuclear Regulatory Commission (L-2011-021), "License Amendment Request for Extended Power Uprate," February 25, 2011, Accession No. ML110730116.
(2) Email from T. Orf (NRC) to C. Wasik (FPL), "St. Lucie 2 EPU Draft RAIs From PRA Licensing (APLA)," July 27, 2011.

By letter L-2011-021 dated February 25, 2011 [Reference 1], Florida Power & Light Company (FPL) requested to amend Renewed Facility Operating License No. NPF-16 and revise the St. Lucie Unit 2 Technical Specifications (TS). The proposed amendment will increase the unit's licensed core thermal power level from 2700 megawatts thermal (MWt) to 3020 MWt and revise the Renewed Facility Operating License and TS to support operation at this increased core thermal power level. This represents an approximate increase of 11.85% and is therefore considered an Extended Power Uprate (EPU).

By email from the NRC Project Manager dated July 27, 2011 [Reference 2], additional information related to the proposed EPU was requested by the NRC staff in the PRA Licensing Branch (APLA) to support their review of the EPU LAR. The request for additional information (RAI) identified four questions. The response to these RAIs is provided in Attachment 1 to this letter.

In accordance with 10 CFR 50.91(b)(1), a copy of this letter is being forwarded to the designated State of Florida official.

This submittal does not alter the significant hazards consideration or environmental assessment previously submitted by FPL letter L-2011-021 [Reference 1].

A001
NRR

This submittal contains no new commitments and no revisions to existing commitments.

Should you have any questions regarding this submittal, please contact Mr. Christopher Wasik, St. Lucie Extended Power Uprate LAR Project Manager, at 772-467-7138.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on AUGUST 25, 2011

Very truly yours,

FOR RLA

Richard L. Anderson
Site Vice President
St. Lucie Plant

Attachment

cc: Mr. William Passetti, Florida Department of Health

Response to Request for Additional Information

The following information is provided by Florida Power & Light (FPL) in response to the U. S. Nuclear Regulatory Commission's (NRC) Request for Additional Information (RAI). This information was requested to support the Extended Power Uprate (EPU) License Amendment Request (LAR) for St. Lucie Unit 2 that was submitted to the NRC by FPL via letter (L-2011-021) dated February 25, 2011 (Accession Number ML110730116).

In an email dated July 27, 2011 from NRC (T. Orf) to FPL (C. Wasik), "St. Lucie 2 EPU Draft RAIs from PRA Licensing (APLA)," the NRC staff requested additional information regarding FPL's request to implement the EPU. The RAI consisted of four (4) questions from the NRC's PRA Licensing Branch (APLA). These four RAI questions and the FPL responses are documented below.

APLA-1:

Section 2.13.2.5 of Attachment 5 states the following on shutdown operations risk:

> **"With the exception of EPU's impact on time available for operator actions, no further *impact of EPU is expected...Reductions in available times for operators to take compensatory or mitigating actions could vary for several to ten or more minutes, dependent on shutdown conditions. The safety evaluation demonstrates that the shorter available time window under EPU would not adversely impact safety consequences."***

Provide additional information for how the safety evaluation demonstrates that shorter available time windows under the EPU would not impact safety consequences. Specifically, address how the EPU impacts the ability of the operator to close containment and provide additional information regarding the reliability and availability of equipment used for shutdown conditions. In addition, explain the impact of the EPU on alternate decay heat removal systems.

Response

The safety evaluation referred to in Section 2.13.2.5 is a risk assessment of St. Lucie Unit 2 Shutdown Cooling (SDC) system operation functions. The most significant impact identified in the post EPU risk assessment is that during mid-loop (or during reduced inventory) operation actions in response to loss of shutdown cooling could be subject to a shorter available time window.

As a practice at St. Lucie Unit 2, shutdown operations with open containment are restricted to plant conditions with normal and high inventory shutdown states. During normal and high inventory shutdown states it is expected that adequate time will be available for operators to respond to events and implement containment closure and that the risk impact will be non-significant.

For mid-loop (or during reduced inventory) operation, in accordance with plant procedures, prior to establishing a plant evolution that would require containment closure, the containment closure teams are required to be trained and tested to ensure that containment can be closed within the specified time to boil. As procedures and the associated personnel training will be maintained to ensure that adequate time to closure will be available, the EPU impact on containment closure will not be significant.

A technical evaluation in LR section 2.8.4.4 of Attachment 5 demonstrates continued compliance with the SDC system cooldown performance requirements at EPU conditions. No plant changes to the SDC system have been made for EPU operating conditions and there are no adverse affects on the design and operating characteristics of the SDC system with respect to its shutdown and long-term cooling function. Therefore, the reliability and availability of the equipment used to shutdown cooling is not expected to change.

St. Lucie Unit 2 uses a tiered risk assessment procedure to manage shutdown risk that involves a qualitative assessment of the configuration of the plant and the availability of various key safety functions. For the EPU the design aspect has been analyzed to satisfy design basis requirements with necessary procedure and configuration changes, and these changes introduced no significant risk to the shutdown risk management process and implementation.

Alternate decay heat removal systems are discussed in LR Section 2.5.4 of Attachment 5, "Component Cooling and Decay Heat Removal."

APLA-2:

Section 2.13.2.6.2 of Attachment 5 provides software parameters from which thermal hydraulic insights were obtained. It is assumed that core damage occurs once the peak fuel region temperatures reaches 2200°F or clad oxidation of a localized fuel region exceeds 1%. For the St. Lucie Unit 1 submittal, the clad oxidation parameter is set to 2%. Please explain why this parameter was changed between the units and the resulting implications. Similarly, in section 2.13.2.6.2, the St. Lucie 1 submittal states that of "more than 70" post-trip human actions, half had reduced operator response times as a result of the EPU, whereas the St. Lucie 2 submittal states that the PRA includes "about 40" post-trip human actions. Please explain why there is a large difference between the number of modeled post-trip human actions between Units 1 and 2 and provide the methodology used to screen human actions for the risk assessment.

Response

The parameter of most importance for the establishment of success criteria is the transient peak fuel temperature. The intent of oxidation limits on the fuel is to ensure the core remains intact (low embrittlement potential) and the hydrogen production is low. Fuel embrittlement conditions are conservatively identified in 10CFR50.46 as 17% local clad oxidation. Hydrogen is indirectly limited in the 10CFR50.46 criteria by requiring that the core-wide oxidation limit be less than 1% of the zircaloy clad. The 1% region-wide oxidation requirement was initially adopted for the success criteria assessment for both St. Lucie Unit 1 and Unit 2. While the intent of the criterion is to limit hydrogen production, the actual resulting consequences to adjusting this criterion is negligible since, for St. Lucie Unit 2, the 1% oxidation of the fuel clad results in a potential for a containment hydrogen concentration in the containment of approximately 0.17v/o[1]. This concentration is well below the hydrogen flammability limit. By moving the criterion in St. Lucie Unit 1 to 2% clad oxidation, success was uniformly based on peak cladding temperature. In fact, this change in success criterion only impacted the screening assessments as the specific cases where this observation occurred were not used in the final determination of the Human Error

[1] v/o-volume percent (percentage referenced to Standard Temperature and Pressure (STP))

Probabilities (HEPs). This was not an issue for St. Lucie Unit 2 as the larger Power Operated Relief Valve (PORV) resulted in a more moderate transient response.

In the St. Lucie Unit 1 statement the 70 post-trip human actions was intended to include consideration of combined actions (i.e., from the dependency analysis), whereas in the St. Lucie Unit 2 write-up the 40 refers to the number of independent human action basic events. When compared on the same basis, St. Lucie 1 has 50 basic events for human actions and St. Lucie Unit 2 has 40 basic events for human actions. For the most part the additional actions for St. Lucie Unit 1 reflect specific differences in the plant design (see also response to APLA-4). In a few instances, differences emerged as a result of modeler preference. Table 1 provides an explanation of the differences between the HRA basic events for the two units.

The primary differences between HRAs arise as a result of the following design differences:

1. St. Lucie Unit 2 PORVs are about twice the size of St. Lucie Unit 1 PORVs

   This feature results in increased capability to implement once through cooling (OTC) actions following a loss of main and auxiliary feedwater. There is no significant impact on an Anticipated Transient Without Scram (ATWS) as St. Lucie Unit 2 operates with the second PORV in the locked closed position. For St. Lucie Unit 2, PRA success criteria for OTC do not require operation of both PORVs.

2. St. Lucie Unit 2 includes a large CST compared to that of St. Lucie Unit 1 (see discussion for APLA-4)

   As a result of the larger inventory, St. Lucie Unit 2 can cope with a wide variety of transient events without the need to replenish the CST, transfer suction to an alternate water source or credit actions to enter shutdown cooling (SDC) prior to CST depletion. This difference results in the need to credit several actions in the St. Lucie Unit 1 PRA that are not credited in the St. Lucie Unit 2 PRA. Specific differences are discussed in Table 1.

3. The flow control valves to the St. Lucie Unit 1 SDC heat exchangers are controlled via Air-Operated Valves (AOVs) while St. Lucie Unit 2 employs Motor Operated Valves (MOVs).

   This difference results in an additional action for St. Lucie Unit 1 to credit recovery actions to establish SDC on loss of instrument air.

4. Differences in Main Feedwater (MFW) Isolation logic

   St. Lucie Unit 1 isolates main feedwater on the combined actuation of a Main Steam Isolation Signal (MSIS) and the Safety Injection Actuation Signal (SIAS). St. Lucie Unit 2 is configured such that MFW isolation is driven by the generation of the MSIS and Auxiliary Feedwater Actuation Signal (AFAS).

5. St. Lucie Unit 2 includes a dedicated hot leg recirculation system using the HPSI pump

   As St. Lucie Unit 1 is an older vintage plant, hot leg recirculation is integrated into the plant procedures using flow paths created via re-alignments of either the preferred Low Pressure Safety Injection (LPSI) or other alternate backup flowpaths. Thus, while both plants credit hot leg recirculation, operator actions to implement this feature are very different.

It should be noted that detailed differences in the design of the replacement steam generator (see response to APLA-4) also result in variations of unit to unit HEPs associated with responding to a subset of total loss of feedwater events. These differences are explicitly treated in the respective plant HRA models.

Table 1: Comparison of Non-Overlapping or Alternatively Modeled Human Actions

PSL 1 HFE	PSL2 HFE	Description of Action	Comments / Notes
AHFPCSTMKUP	No equivalent action for St. Lucie Unit 2	Failure to provide long-term makeup to the CST from the TWST	St. Lucie Unit 1 credits use of the Treated Water Storage Tank (TWST) as a makeup source to the St. Lucie Unit 1 CST. The St. Lucie Unit 1 CST capacity is unable to support long term heat removal. While this action is available for St. Lucie Unit 2, it is conservatively neglected in modeling long term heat removal because the St. Lucie Unit 2 CST is large enough to remove long term decay heat.
AHFPSWU2CST	No equivalent action for St. Lucie Unit 2	Failure to cross-tie AFW suction to Unit 2 CST when makeup not available from the TWST	St. Lucie Unit 1 credits cross-tying to the St. Lucie Unit 2 CST as a makeup source to the St. Lucie Unit 1 CST. The St. Lucie Unit 1 CST capacity is unable to support long term heat removal. St. Lucie Unit 2 CST includes volume capacity dedicated to Unit 1 CST if cross-tie is performed. Such capacity is controlled by Unit 2 Tech Specs. An equivalent action is not available for St. Lucie Unit 2. St. Lucie Unit 2 CST is large enough to remove long term decay heat.
AHFPXCON	St. Lucie Unit 1 action identical to AHFPXCON-N<4 for St. Lucie Unit 2	Failure to manually cross-connect AFW trains to feed steam generators	St. Lucie Unit 2 subsumed this action into AHFPXCON-N<4. This action is not different between the units.
FHFP1RECMFW	St. Lucie Unit 1 action identical to FHFP2RECMFW-L for St. Lucie Unit 2	Failure to restore main feedwater flow to the steam generators following a transient.	St. Lucie Unit 2 subsumed this action into FHFP2RECMFW-L. This action is not different between the units.

Table 1: Comparison of Non-Overlapping or Alternatively Modeled Human Actions			
PSL 1 HFE	**PSL2 HFE**	**Description of Action**	**Comments / Notes**
FHFP1RECMFWI	No equivalent action for St. Lucie Unit 2	Failure to restore main feedwater flow to the steam generators following a SIAS	This action applies when MFW isolation is caused by a SIAS signal. For St. Lucie Unit 2 this action is not included since closure requires Main Steam Isolation Signal (MSIS) and Auxiliary Feedwater Actuation Signal (AFAS).
St. Lucie Unit 1 uses action JHFP1HOTLEG to implement hot leg recirculation	GHFP2HOTLEG	Failure to initiate simultaneous cold- and hot-leg injection following a large LOCA	For St. Lucie Unit 1, hot leg recirculation is integrated into the plant procedures using flow paths created via re-alignments of the preferred LPSI system or other backup systems as necessary (this is credited in the PRA with JHFP1HOTLEG). St. Lucie Unit 2 includes a dedicated hot leg recirculation system using the HPSI pump (this is credited in the PRA with GHFP2HOTLEG).
GHFPOTCTGT42	No equivalent action for St. Lucie Unit 2	Failure to establish OTC after total loss of feedwater (AFW for at least 4 hr, 2 PORVs available)	Due to the large size of the St. Lucie Unit 2 PORVs, the second PORV is blocked during normal operation by Technical Specifications. Two PORV OTC operation is not required in St. Lucie Unit 2. Therefore, the St. Lucie Unit 1 action for implementing OTC with two PORVs is not credited for St. Lucie Unit 2.
JHFP1HOTLEG	St. Lucie Unit 2 uses action GHFP2HOTLEG to implement hot leg recirculation	Failure to initiate simultaneous cold- and hot-leg injection following a large LOCA	For St. Lucie Unit 1, hot leg recirculation is integrated into the plant procedures using flow paths created via re-alignments of the preferred LPSI system or the other backup systems as necessary (this is credited in the PRA with JHFP1HOTLEG). St. Lucie Unit 2 includes a dedicated hot leg recirculation system using the HPSI pump (this is credited in the PRA with GHFP2HOTLEG).
JHFPMANIA	No equivalent action for St. Lucie Unit 2	Failure to cool down and establish shutdown cooling following a transient with loss of instrument air	SDC Flow Control Valves in St. Lucie Unit 1 are AOVs. These control valves are MOVs in St. Lucie Unit 2. Therefore, this action is not required for St. Lucie Unit 2.

Table 1: Comparison of Non-Overlapping or Alternatively Modeled Human Actions			
PSL 1 HFE	**PSL2 HFE**	**Description of Action**	**Comments / Notes**
JHFPSDCT	No equivalent action for St. Lucie Unit 2	Failure to cool down and establish shutdown cooling following a transient	As a result of the smaller CST, St. Lucie Unit 1 credits back-up actions to implement SDC for long term cooling. Equivalent actions are available to St. Lucie Unit 2 but are not required since the St. Lucie Unit 2 CST is large enough to remove long term decay heat.
JHFPSDCW	No equivalent action for St. Lucie Unit 2	Failure to cool down and establish shutdown cooling following an ATWS	See note for JHFPSDCT.
OHFPPORVISOW	No equivalent action for St. Lucie Unit 2	Control Room Operator Fails to Isolate PORV Path (ATWS)	Due to double PORV size in Unit 2 in comparison to Unit 1, there is minimal ATWS impact in Unit 2, and thus this action is not credited for St. Lucie Unit 2 as one Unit 2 PORV is blocked.

APLA-3:

Section 2.13.2.3.4.2 of Attachment 5 states that if the Moderator Temperature Coefficient (MTC) increased from 0.22 to 0.25, the delta CDF from the baseline plant would be 3.6E-8 per year with a corresponding reduction in LERF of 1.6E-08 per year. Please provide an explanation for why there is a reduction in LERF for ATWS for this application. Describe why the result of this analysis is different than the ATWS analysis submitted in Section 2.13.2.9.5.2.2.

Response

The LERF and CDF both increased when referenced to the ATWS event. When referenced to the ATWS scenario the ATWS CDF increased by 4.61E-08 per year and LERF increased by 1.11E-09 per year. When referenced to the baseline change in CDF and LERF (that is, the total post-EPU CDF less the total pre-EPU CDF and, the total post-EPU LERF less the total pre-EPU LERF, which are -9.9E-09/yr and -1.71E-08/yr, respectively), the change in CDF becomes 3.6E-08/yr and the change in LERF becomes -1.6E-08/yr. Table 2 provides a summary of this impact.

Table 2: Impact of Plant-Specific Unfavorable MTC on EPU		
Impact Description	Δ CDF (EPU – Pre-EPU)	Δ LERF (EPU – Pre-EPU)
Total Plant Baseline Risk Change (A)	-9.90E-09	-1.71E-08
ATWS Event Specific MTC Impact (B)	4.61E-08	1.11E-09
Net Delta EPU and Baseline (A+B)	3.62E-08	-1.60E-08

APLA-4:

Please explain major design differences between Unit 1 and 2 as well as any differences in PRA modeling for the pre-EPU plant. In addition, explain differences in PRA modeling associated with the extended power uprate between Units 1 and 2.

Response

While St. Lucie Units 1 and 2 operate at the same power and are both Combustion Engineering designed PWRs, the two plants have very distinct differences that have a direct impact on PRA. The key differences of these plants that impact the PRA are summarized in Table 3. From a risk perspective the most significant differences between the two units is the PORV size and details of the replacement SG design. These changes result in smaller operator action timing windows and subsequently higher HEPs for the Total Loss of Feedwater (TLOFW)events.

Table 3: Summary of St. Lucie Unit 1 and Unit 2 Design Differences with PRA Significance			
Feature	St. Lucie Unit 1	St. Lucie Unit 2	Comment
PORV Relief Capacity	Includes two (2) PORVs with a minimum design capacity of 153,000 lbm/hr/PORV	Includes two (2) PORVs with a minimum design capacity of 395,000 lbm/hr/PORV. The Unit 2 Technical Specification requires plant operation with one PORV closed	The larger PORV capability for St. Lucie Unit 2 improves the ability of the plant to implement Once Through Cooling (OTC) strategies following total loss of main and auxiliary feedwater. Due to the large size of the St. Lucie Unit 2 PORVs, the second PORV is blocked during normal operation by Technical Specifications. Based on this, the impact of the larger PORV capability with respect to ATWS events is considered negligible.
SG Design	Includes a B&W designed RSG	Includes an Areva designed RSG	The Replacement Steam Generator (RSG) are similar designs, however differences in the geometry of the RSGs can result in less inventory available at the low level reactor trip set point.

Table 3: Summary of St. Lucie Unit 1 and Unit 2 Design Differences with PRA Significance

Feature	St. Lucie Unit 1	St. Lucie Unit 2	Comment
CST Volume	Includes a moderate capacity CST. Note that the combined St. Lucie Unit 1 and St. Lucie Unit 2 CST volumes are capable of removing long term decay heat from a dual unit trip.	Includes a large capacity CST. St. Lucie Unit 2 CST includes volume capacity dedicated to Unit 1 CST if cross-tie is performed. Such capacity is controlled by Unit 2 Tech Specs.	The larger sized CST at St. Lucie Unit 2 allows the plant to cooldown without the need to cross-tie to an alternate water source.
Hot Leg Recirculation	Hot side injection relies on multiple prioritized implementation processes which involve manual alignments to the preferred LPSI system or other alternate backup systems as necessary.	Hot side injection includes an integrated hot side injection path involving only HPSI injection/recirculation.	Differences in the hot leg recirculation system designs result in the need for different operator actions between the two units. The impact of the differences in this design is on the order of 4E-07 per year and is focused primarily on the Large LOCA scenarios.
Shutdown Cooling System	Unit 1 SDC heat exchanger flow control valves are air operated.	Unit 2 SDC heat exchanger flow control valves are motor operated.	The differences in SDC heat exchanger flow control valve control allow a St. Lucie Unit 1 recovery action which is not available for St. Lucie Unit 2.

Plant differences are reflected in the plant risk metrics. Overall, the plant design differences result in St. Lucie Unit 2 having a lower internal events CDF than that of St. Lucie Unit 1. The CDFs differ by about 18% pre-EPU and about 11% post EPU. The larger PORVs and greater capacity CST of ST. Lucie Unit 2 contribute to significant reductions in the risk of loss of main feedwater and Small LOCA initiators. The lesser importance of loss of feedwater events for St. Lucie Unit 2 is also reflected in the smaller impact of enhanced AFW system surveillances post-EPU.