FPL.

October 12, 2011

L-2011-406
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 NRC (T. Orf) to FPL (C. Wasik), "St. Lucie 2 EPU -- draft RAIs from Balance-of-Plant (SBPB)," August 17, 2011
(3) U.S. Nuclear Regulatory Commission (H. N. Berkow) to Siemens Westinghouse Power Corporation (S. Dembkowski), "Final Safety Evaluation Regarding Referencing the Siemens Technical Report No. CT-27332, Revision 2, 'Missile Probability Analysis for the Siemens 13.9 M^2 Retrofit Design of Low-Pressure Turbine by Siemens AG' (TAC No. MB7964," March 30, 2004, Accession No. ML040930616

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 August 17, 2011 [Reference 2], additional information was requested by the NRC staff in the Balance-of-Plant Branch (SBPB) to support their review of the EPU LAR. The draft request for additional information (RAI) identified five 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.

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NRR

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

This submittal contains no revisions to existing commitments. A new commitment is made pursuant to the conditions in the NRC Final Safety Evaluation [Reference 3] as follows:

FPL commits to inform the NRC about turbine disk inspection results and plans to reduce the probability of turbine missile generation, P_1, for continued operation should cracks be detected in the inspection.

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 12-October-2011

Very truly yours,

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 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 Nuclear Plant 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 August 17, 2011 from NRC (Tracy Orf) to FPL (Chris Wasik), Subject: "St. Lucie 2 EPU -- draft RAIs from Balance-of-Plant (SBPB)," the Balance-of-Plant Branch identified five questions as part of their review of the EPU LAR. The questions relate to: (1) loss of normal feedwater event; (2) auxiliary feedwater system motor-driven pump design; (3) spent fuel pool water temperature; (4) turbine missile evaluation methodology; and (5) transient testing of the feedwater system prior to EPU implementation. These five draft RAI questions and the FPL responses are documented below.

SBPB-1:

Appendix 10.4.9A, "Auxiliary Feedwater System Requirements Evaluation," to Amendment 19 of the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR), describes that the analysis of the loss of main feedwater with offsite power available was the limiting event with respect to steam generator inventory. The loss of normal feedwater (LNF) analysis discussed in Section 2.5.4.5.2.4, "Results," of the license amendment request (LAR) supporting the extended power uprate (EPU) license amendment request states that the auxiliary feedwater (AFW) system is sized to remove the decay heat and pump heat associated with the event, based on an analysis at nominal plant conditions. However, the results do not directly address the assumptions used in the analysis, the AFW pump flow, and the minimum steam generator inventory determined by the analysis. In addition, the analysis notes that nominal parameter values were used in the analysis.

Provide the assumptions, boundary conditions, and results of the LNF accident analysis. Include the assumed AFW pump flow, the steam generator pressure, the minimum steam generator water inventory, and the basis for concluding the minimum inventory would support continued removal of decay and pump heat. Explain how the use of nominal parameter values in the limiting accident analysis for steam generator inventory would satisfy the design control requirements of Appendix B to 10 CFR Part 50 for operation at EPU conditions.

Response:

The Loss of Normal Feedwater (LNF) analysis described in Section 2.5.4.5 of the EPU LAR is not the licensing basis, Chapter 15 safety analysis. It is an auxiliary analysis performed to ensure that the Auxiliary Feedwater (AFW) system is sized sufficiently for the EPU. According to the St. Lucie Unit 2 UFSAR Section 10.4.9A, the AFW design bases are to ensure:

1. Sufficient capability exists for removal of decay heat from the reactor core.
2. The ability to reduce Reactor Coolant System (RCS) temperatures to entry temperatures for activating the shutdown cooling system.

3. Prevent lifting of the pressurizer safety valves (PSVs) when considered in conjunction with the power operated relief valves (PORVs).

Item 1, above, is satisfied by assuring that the steam generators do not reach a dryout condition. As such, as long as inventory remains in the steam generators, the AFW system provides sufficient capability for decay heat removal. Item 2, above, is not explicitly analyzed in the LNF analysis, however, it is demonstrated that subcooling margin is maintained throughout the entire event and inventory remains in the steam generators. Item 3, above, is satisfied by assuring the maximum pressurizer pressure remains below the PSV opening setpoint.

In addition to these three requirements, an additional criterion is imposed on the LNF analysis. Maximum pressurizer water volume must remain less than 1519 ft^3, thus ensuring a water solid state is not reached and the accident does not propagate into a more severe event.

Consistent with the analyses performed in UFSAR Section 10.4.9A, the LNF AFW analysis performed for the EPU is a best estimate analysis with some parameters biased in the conservative direction. Thus, nominal initial parameters were considered. Cases with and without offsite power were considered. Table 1 illustrates the key analysis parameters for both offsite power available (LNF) and offsite power unavailable (LNF + LOOP).

Table 1: Key Analysis Parameters

		LNF	LNF + LOOP
Core Power		100% + Uncertainty (3030 MWt)	100% + Uncertainty (3030 MWt)
Loop Flow Rate		Thermal Design Flow (187500 gpm)	Thermal Design Flow (187500 gpm) prior to coastdown
RCS Temperature		Hi & Low nominal (578.5 & 563 °F)	Hi & Low nominal (578.5 & 563 °F)
Pressurizer	**Initial Pressure**	Nominal (2250 psia)	Nominal (2250 psia)
	Initial Water Level	Nominal (63%)	Nominal (63%)
	Charging/Letdown	Available	Unavailable
	Heaters	Available	Unavailable
	PORV	Available	Available
	Spray	Available	Available (for conservatism in pressurizer fill)
Steam Generator	**Initial Water Level**	Nominal (65%)	Nominal (65%)
	Tube Conditions & Steam Generator Tube Plugging	Fouled, 10%	Fouled, 10%
	Atmospheric Dump Valves (ADVs)*	Modeled to mimic steam bypass, SG pressure controlled to 900 psia	Conservatively modeled to minimize SG inventory, SG pressure controlled to 900 psia*

Table 1: Key Analysis Parameters, continued			
		LNF	**LNF + LOOP**
Auxiliary Feedwater	**Pumps**	2 Motor Driven AFW Pumps	2 Motor Driven AFW Pumps
	Flowrate	275 gpm per Motor Driven AFW Pump	275 gpm per Motor Driven AFW Pump
	Delay	330 sec.	330 sec.
	Actuation Setpoint	Nominal – Uncertainty (13.0 % Narrow Range Setpoint)	Nominal – Uncertainty (13.0 % Narrow Range Setpoint)
Loss of Offsite Power		Not Assumed	Assumed on Reactor Trip
Reactor Trip Setpoint	**Pressurizer Hi Pressure**	2370 psia	2370 psia
	Low-Low SG Level	Nominal – Uncertainty (14.5 % Narrow Range Setpoint)	Nominal – Uncertainty (14.5 % Narrow Range Setpoint)
Reactivity		Beginning of Cycle w/ maximum value of delayed neutron fraction, β	Beginning of Cycle w/ maximum value of delayed neutron fraction, β

* Note that during a LOOP, the steam bypass system is unavailable. ADVs are still modeled in the LOOP case to conservatively minimize SG inventory during the event.

The LNF analysis performed in accordance with UFSAR Section 10.4.9A shows that greater than 10% of the initial steam generator mass exists in either generator at the end of the transient. The pressurizer water volume remains below 1519 ft^3, and as such, the pressurizer does not reach a water solid condition. Pressurizer pressure, despite rising initially, remains below the PSV setpoint and the PSVs do not open during the event. Subcooling margin is maintained throughout the entire event.

The sequence of events for the limiting LNF case (offsite power available) is presented below along with the plots for the RCS temperature (Figure 1) and the SG water inventory (Figure 2). The analysis has been run conservatively for 1 hour with no operator action.

Table 2: LNF with Offsite Power Available - Sequence of Events		
Time (sec)	**Event**	**Setpoint/Value**
0 - 20	Steady State Period	
20.0	Loss of feedwater to both steam generators	
57.8	Reactor trip signal on high pressurizer pressure	2370 psia
57.8	PORV Actuates	
58.2	Reactor Trip	
60.2	Turbine Trip*	
63.7	Low steam generator level auxiliary feedwater actuation signal setpoint reached	13.0 % Narrow Range Setpoint
393.7	Auxiliary feedwater flow reaches the steam generators	275 gpm/SG
1162.5	Maximum pressurizer level	1512.2 ft^3
1222.5	Minimum steam generator inventory	14,444 lbm/SG
3620.0	Operator takes action to commence plant cooldown (1 hr from start of event)	

* Turbine Trip is not credited in the transient analysis.

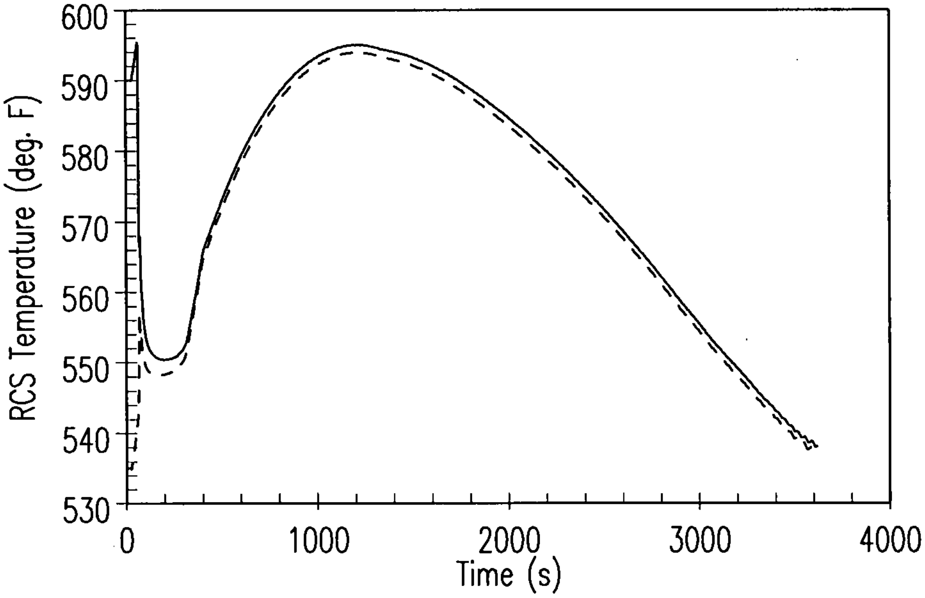

Figure 1:
LNF With Offsite Power Available:
Hot and Cold Leg Temperature vs. Time

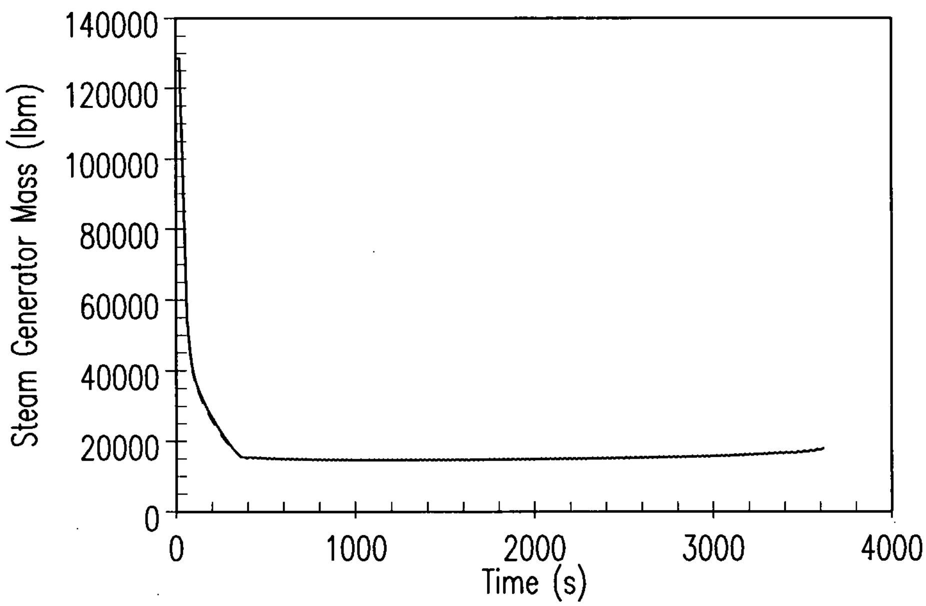

Figure 2:
LNF With Offsite Power Available: Steam Generator Mass vs. Time

The Loss of Normal Feedwater (LNF) Chapter 15 safety analysis is described in Section 2.8.5.2.3 of the St. Lucie Unit 2 EPU licensing report. Section 2.8.5.2.3 indicates that the LNF accident analysis is not explicitly analyzed for the St. Lucie Unit 2 EPU.

The LNF event is classified as an Anticipated Operational Occurrence (AOO). An AOO has the following acceptance criteria:

- Maximum pressure in the Reactor Coolant System (RCS) and Main Steam System (MSS) will be maintained below 110% of the design pressure.
- The Specified Acceptable Fuel Design Limits (SAFDLs) are not exceeded, in particular the Departure from Nucleate Boiling Ratio (DNBR).
- The event does not propagate to a more serious event. For the LNF event, long term cooling must be verified by demonstrating the pressurizer does not become water solid. This ensures that a more limiting event is not generated.

With respect to RCS and MSS overpressurization criteria, the LNF event is bounded by the loss of condenser vacuum event. With respect to SAFDLs and core consequences for the Chapter 15 LNF safety analysis, the LNF event is bounded by the loss of forced reactor coolant flow event. With respect to the propagation to a more serious event, the LNF analysis performed for UFSAR Section 10.4.9A at EPU conditions demonstrates that a water solid condition does not result.

<u>**SBPB-2:**</u>
Table 10.4.1, "Component Design Parameters," of Amendment 19 of the St. Lucie Unit 2 UFSAR lists the motor driven AFW pump capacity as 300 gallons per minute (gpm), including minimum recirculation flow of 50 gpm, at a pump head of 2660 feet [~1150 psid]. However, the bases for TS 3/4.7.1.2, which were provided in Attachment 4 to the LAR, specify a delivered flow to the entrance of the steam generators of 320 gpm at 1000psia (MSSV setpoint) for each motor-driven pump. Reconcile these flow values considering the flow head loss at 320 gpm and the elevation difference between the pump discharge and the steam generator water surface. Provide the motor driven AFW pump performance curves and the results of full-flow inservice testing supporting the specified performance.

<u>**Response:**</u>
The capacity of 300 gpm in Table 10.4-1 of the St. Lucie Unit 2 UFSAR is based on the original sizing for the AFW pumps as demonstrated by the manufacturer's pump curve. A St. Lucie calculation, which considers flow head loss and elevation head, demonstrates that using this curve, the motor driven AFW pumps are capable of supplying 320 gpm to the entrance of the steam generators at 1000 psia as stated in the Bases for Technical Specification (TS) 3/4.7.1.2. The EPU accident analysis input for AFW flow is 275 gpm per motor driven pump to a steam generator at 1000 psia.

In-Service full flow performance testing for the motor-driven AFW pumps is provided in plant procedures. These procedures test the pumps at a flow of 246 gpm which, as required by the ASME OM Code, is within ± 20% of the 300 gpm flow rate identified in UFSAR Table 10.4-1.

The manufacturer's pump curve and the results of the latest full flow test for each pump are provided in Figures SBPB2-1 through SBPB2-3, respectively.

SBPB-3:

Section 9.1.3.3 of the St. Lucie 2 UFSAR states that, prior to commencing a full-core offload, an outage specific engineering evaluation will be preformed to evaluate the spent fuel pool (SFP) coolant temperature while assuming a cooling capacity equivalent to a single train of the SFP cooling system, and this evaluation will outline the need for contingency actions. Section 2.5.4.1.2 of the LAR supporting the EPU states the following for the scenario involving a full core offload with the failure of a fuel pool cooling train:

> **The maximum SFP bulk temperature rise (also called the thermal overshoot) that could result from a worst-case spent fuel pool cooling train failure has been determined to be 27°F for a full core fuel offload initiated 140 hours after reactor shutdown. The procedural upper limit for the spent fuel pool temperature during a full core offload will be set so as to ensure the 150°F limit is not exceeded in the event of a failure of one fuel pool cooling train, after accounting for the maximum thermal overshoot.**

Clarify how the procedural upper limit would ensure the pool temperature limit would not be exceeded, considering the committed heat load once the fuel is placed in the spent fuel pool and the large thermal inertia of the pool delaying the indicated temperature relative to peak pool temperature.

Response:

The spent fuel pool (SFP) cooling analysis performed for EPU demonstrated that the maximum temperature rise (thermal overshoot) resulting from a worst–case analysis with one SFP cooling train failure is 27°F under the following conditions:

- A full core offload is present in the SFP, initiated at 140 hours after reactor shutdown at an average of 7 assemblies per hour.
- The component cooling water (CCW) temperature is 95°F.
- A failure of one train of SFP cooling occurs at the end of the full core offload.

Thermal overshoot is the temperature difference between the maximum SFP bulk temperature following the failure of one SFP cooling train and the SFP bulk temperature at the end of fuel transfer (time when last assembly is offloaded) when the failure of one train of SFP cooling is assumed to occur. The thermal analysis performed subsequent to the failure of one train of SFP cooling used the same methodology as described in LR Section 2.5.4.1.2 and accounts for the thermal capacity of the pool in the calculation of the SFP bulk temperature as a function time.

Since the maximum thermal overshot for the worst case is 27°F, the procedural upper limit for the SFP bulk temperature will be set less than 123°F, so that the maximum bulk temperature, with the failure of one train of cooling, will not exceed 150°F. This procedural upper limit of 123°F is considered acceptable to maintain SFP bulk temperature less than or equal to 150°F based on the following:

1. The rise of SFP temperature of 27°F is based on a conservative heat load corresponding to assemblies being offloaded at 7 assemblies per hour. Note that with a lower but still conservative offload rate of 5 assemblies per hour, the thermal overshoot reduces by more than 2°F.
2. The SFP heat load assumes SFP being full with all EPU fuel, discharged in the SFP with conservative batch size and schedule, providing additional margin to the thermal overshoot.
3. The thermal overshoot of 27°F accounts for the thermal capacity of the pool in the calculation of the maximum bulk temperature.

The indicated temperature is expected to be close to the bulk temperature for the following reasons:

1. The SFP heat load is distributed in the SFP.
2. With two trains of cooling in operation prior to the thermal overshoot calculation, there will be sufficient mixing in the SFP when considering the pool configuration with inlet and outlet being on opposite sides of the pool.
3. With the SFP bulk temperature rise being on the order of ~1°F/hr, and taking into account the heat load distribution and coolant movement corresponding to 2 trains operating, the indicated temperature is expected to remain close to the bulk temperature.

Thus, maintaining the SFP temperature below 123°F with two cooling trains in operation, the SFP bulk temperature will not exceed 150°F even when considering the failure of one train of SFP cooling.

SBPB-4:
Section 3.5.1.3, "Turbine Missiles," of Amendment 19 of the St. Lucie Unit 2 UFSAR describes the plant licensing basis for turbine missile protection. The staff found the description reflected an assumed turbine missile generation frequency, calculated the probability that any of the missiles would damage a critical component, and compared the resulting frequency against an acceptance criterion frequency of 1 E-07 per year. Sections 7.7 and 10.2 address design of the turbine control system and the turbine, but do not substantively address turbine missile protection. The discussion provided in Section 2.5.1.3 of the LAR described a different approach to turbine missile protection that is based solely on a calculated turbine missile generation frequency, and which referenced a topical report. Reconcile these different approaches to turbine missile protection. If the missile generation frequency is to be adopted consistent with the referenced topical report, provide the assumptions and results supporting the revised analytical method and address items listed in the staff topical report safety evaluation.

Response:
Evaluation of turbine missiles has historically followed Regulatory Guide 1.115, "Protection Against Low-Trajectory Turbine Missiles", and Standard Review Plan (SRP) Section 3.5.1.3, "Turbine Missiles". These guidance documents are identified in the UFSAR as the regulatory basis for the existing turbine missile analysis presented in UFSAR Section 3.5.1.3. As specified in SRP Section 3.5.1.3, the probability of unacceptable damage from turbine missiles is expressed as the product of three probability terms: (P_1) the probability of turbine missile generation resulting in the ejection of disk fragments through the turbine casing, (P_2) the

probability of ejected missiles perforating intervening barriers and striking safety related structures, systems or components (SSCs) and (P_3) the probability of struck SSCs failing to perform their safety functions. An acceptance criterion frequency of 1 E-07 per year was specified. The turbine missile analysis presented in Section 3.5.1.3 of the PSL2 UFSAR reflects this approach. As discussed in Section 2.5.1.2 of the EPU LAR, the emphasis in turbine missile evaluation has shifted from the strike and damage probability terms P_2 & P_3, to the missile generation probability term P_1. This shift in emphasis is also documented in the NRC Final Safety Evaluation (ML040930616) for Siemens Technical Report CT-27332, Revision 2 "Missile Probability Analysis for the Siemens 13.9 M^2 Retrofit Design of Low-Pressure Turbine by Siemens AG". As further discussed in both of these source documents, a P_1 probability term acceptance criterion of 1E-5 per year has been established for unfavorably oriented turbines (i.e. where the turbine shaft orientation results in most safety related components being within the low trajectory hazard zone).

A turbine missile analysis was performed in support of EPU which reflects replacement of the low pressure (LP) turbine rotors with the Siemens BB281-13.9 m^2 design. Its conclusions are similar to the existing analysis in that the probability of a disk failure with casing penetration is significantly below the NRC's limit value.

The analytical approach employed for the turbine missile analysis is in compliance with Siemens Westinghouse Topical Report TP-04124, "Missile Probability Analysis for the Siemens 13.9M^2 Retrofit Design of Low-Pressure Turbine by Siemens AG." The NRC issued a Safety Evaluation Report to Siemens Westinghouse Power Corporation (SWPC) which addressed, in part, the ability to reference SWPC Technical Report CT-27332, Revision 2 in retrofit applications such as in the case of St. Lucie Unit 2. CT-27332, Revision 2 justifies external missile probabilities out to 100,000 hours in comparison to the NRC limit.

The Topical Report expresses the probability of an external missile (P_1) emanating from the turbine-generator by conservatively evaluating two distinct types of LP shrunk-on disk failures, namely:

1. failure at normal operating speed up to 120% of the rated speed P_r and

2. failure due to run-away overspeed greater than 120% of rated speed P_o for all LP disks as follows:

   $$\mathbf{P_1 = P_r + P_o = \sum^{N}_{i=1} P^{i}_{2r} * P^{i}_{3r} + P_{1o}}$$

   Where:

   P_1 is the probability of an external missile,

   P_r is the probability of an external missile for speeds up to 120% of rated speed,

   P_o is the probability of an external missile for speeds greater than 120% of rated speed,

   N, i is the total and current number of disks,

   P^{i}_{2r} is the probability of disk # i burst up to 120% of rated speed due to stress corrosion crack growth to critical size,

P^{i}_{3r} is the probability of casing penetration given a burst of the disk # i up to 120% of rated speed,

P_{1o} is the probability of a run-away overspeed incident (>120% of rated speed) due to a system separation initiation event followed by a failure of overspeed protection system.

The P_o term reduces to the P_{1o} term based on the conservative assumptions in the analysis that the probability of disk failure and probability of casing penetration are both equal to 1.0 for speeds greater than 120%.

The derivation of this equation is presented in the Topical Report.

For the calculation of P_r, a Monte-Carlo simulation technique involving successive deterministic fracture mechanics calculations using randomly selected values of variables is used. As a failure condition, the brittle fracture mode is assumed. Selected random variables that are defined by finite element analysis are employed and a critical crack size is defined. Limits are based on the applicability limitation of linear-elastic fracture mechanics and do not represent an imminent burst condition. In the final summation $\sum^{4}_{i=1} P_r$ was determined to be approximately two orders of magnitude below the NRC limit value for up to 100,000 operating hours between disk inspections providing that no cracks are detected in the discs.

Due to the conservative assumptions inherent in the turbine missile analysis methodology in the Siemens analysis, the calculation of disk failure probability and casing penetration (P_{2r} and P_{3r}) is treated completely independently from the calculation of system separation probability and overspeed protection system failure probability (P_{1o}) as detailed in the Westinghouse Owners Group (WOG) analysis, WCAP-16501, "Extension of Turbine Valve Test Frequency Up to 6 Months for BB-296 Siemens Power Generation Turbines With Steam Chests, Rev.0".

Turbine speeds greater than 120% of rated speed can only be reached due to a total functional failure of the turbine overspeed protection system. As discussed in Section 2.5.1.2.2.2.2 of the EPU LAR, the larger inertia of the replacement LP rotors outweighed other EPU effects such that the net effect is a 1% decrease in expected maximum turbine speed during a loss of load event. Specifically, the expected change in the inertia of the rotor system will be approximately 47%. Also, the efficiency improvements due to the HP and LP upgrades and increase in thermal power will result in an increase in the power output of the turbine of approximately 14.9%. The increase in the amount of energy during the trip delays and valve closing as well as expansion of the entrapped steam will be higher at the EPU condition. However, this increase is more than offset by the increased inertia of the rotor train. Thus, the calculated overspeed will be approximately 1% lower than the original equipment. The calculated overspeed upon a breaker opening at full power EPU conditions is 114.7% based upon a trip setpoint of 111%.

P_{1o} or the probability of a run-away overspeed incident (>120% of rated speed) is the product of the system separation probability and the overspeed protection system failure probability and it is based on Westinghouse Owners Group (WOG) analysis WCAP-16501. The existing overspeed protection system failure probability, P_{1o} documented in WCAP-16501 remains bounding for the upgraded turbine control system to be installed as part of EPU at St. Lucie Unit 2. The modifications being made to enhance the reliability of the controls system, and thereby reduce the probability of reaching a run-away overspeed condition, are not being credited in the failure probability analysis. Since the P_{1o} probability from WCAP-16501 is bounding for both the current and EPU turbine overspeed protection system St. Lucie designs, the existing 18 month fuel cycle conditional probability of destructive overspeed remains unchanged due to the power uprate. WCAP-16501 was prepared for a number of participating plants including St Lucie, North Anna, McGuire, Waterford, Shearon Harris, Farley, Byron and Braidwood. Some of the participating plants, including Byron Units 1 & 2, had previously upgraded their turbine control and turbine protection systems based on a Westinghouse Ovation design similar to the proposed new St Lucie Unit 2 Ovation design for EPU.

The design of the Ovation turbine control and protection system at St. Lucie Unit 2 includes two independent subsystems each with redundant processors. Each subsystem provides turbine overspeed protection in 2 out of 3 logic. Enhanced design features include: redundant and diverse speed probes, speed sensing modules that function independent of control processors, and a redundant and diverse Overspeed Protection Control (OPC) trip system at 103% overspeed. The Ovation turbine control and protection system enhances control system reliability and thereby reduces the probability of reaching a run-away overspeed condition. Thus, continued usage of the existing overspeed protection system failure probability in the overspeed analysis is conservative.

Total probability of an external turbine missile (P_1) for St. Lucie Unit 2 at 100,000 hours inspection interval is approximately 60 times less than the NRC limit value of 11.42 E-5 per 100,000 hours inspection interval. Therefore, it has been shown that the replacement Siemens rotors provided with a Westinghouse-provided Ovation control system continue to meet the current design analysis for missile protection under EPU conditions.

The NRC Final Safety Evaluation Report for Siemens Technical Report CT-27332, Revision 2 requires that the following items be addressed in any associated submittal:

a) State the approximate date for the turbine disk inspection at the end of 100,000 hours of rotor operation.

<u>Response</u>
The St. Lucie Unit 2 replacement LP turbine rotors were placed in service at the conclusion of the SL2-19 outage (April, 2011). In accordance with the preventative maintenance (PM) program, the turbine disk inspection is scheduled to be performed once every 100,000 hours of rotor operation. The first inspection will therefore occur around April, 2021.

b) Provide a commitment to inform the NRC about turbine disk inspection results and plans to reduce the probability of turbine missile generation, P_1, for continued operation should cracks be detected in the inspection.

<u>Response</u>
FPL commits to inform the NRC about turbine disk inspection results and plans to reduce the probability of turbine missile generation, P_1, for continued operation should cracks be detected in the inspection.

c) Provide justification for any additional turbine missile analyses, or minor deviations that may be plant specific.

Response
Beyond the discussions provided above, there are no additional turbine missile analyses or plant specific deviations that require further justification.

SBPB-05:
The licensee indicated in Section 2.12 of the LAR that equipment modifications are being made to the feedwater system to support EPU conditions and that the feedwater system response would be monitored during power ascension. The licensee also stated that the transient response for the feedwater system during EPU conditions was modeled using the CENTS computer code. However, the staff is concerned that CENTS-modeled transient for the feedwater system may not reflect the actual transient response of the replacement feedwater pumps, along with its compatibility with the modified feedwater control system, during EPU conditions.

Discuss how the feedwater system will be assessed with actual transient testing prior to EPU implementation to confirm that the replacement feedwater pumps and feedwater control system will respond in a manner similar as the CENTS-modeled transient, or if actual transient testing will not be done, justify why it is not needed.

Response:
EPU License Amendment Request (LAR), Attachment 5, Licensing Report Section 2.12.1.2.6, discusses the CENTS code model and its general application. LAR Section 2.12.1.2.7 includes the application of CENTS to load transients. The following discussion provides supplemental information regarding the CENTS modeling and the justification for why actual transient testing is not required, with emphasis on the feedwater (FW) system.

CENTS was benchmarked with operating data in order to refine the EPU model. The following St. Lucie transients were used in the benchmarking process:

- Unit 2 manual reactor trip from 100% power on June 4, 2008 following a loss of a main FW pump, and
- Unit 2 manual reactor trip from 100% power on June 7, 2008 following a condensate pump trip.

In addition, Unit 1 and Unit 2 are very similar with respect to overall plant design and behavior of NSSS control systems. The above Unit 2 events were used in the benchmarking process for the Unit 1 CENTS model with excellent results. The Unit 1 CENTS model was also benchmarked against specific Unit 1 events, including non-trip operational transients. Since the Unit 2 CENTS model is similar to the Unit 1 CENTS model, the Unit 1 CENTS benchmarking supports validation of the Unit 2 CENTS model. For benchmarking against each of the Unit 2 trip events and the Unit 1 non-trip operational events, short duration time interval data for a large number of key plant parameters was available for electronic comparison.

A CENTS model base deck was developed taking into account EPU conditions. The model was built to incorporate the applicable EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The EPU FW modifications modeled in the CENTS transient analyses include the valve C_v for the modified FW flow control valves, the pump curve for the new FW pumps, and the new FW control system settings. These modifications do not change the fundamental design and operation of the FW system. For the flow control valves, the valve trim is new, but the valve body is not replaced. For the new pumps, the motor is not replaced. For the FW control system, Distributed Control System (DCS) software testing will include validation that the FW control system is correctly modeled in the CENTS code.

The agreement between the CENTS model results and the actual plant response during the benchmarking process, and the fact that the FW equipment systems have been appropriately incorporated in the CENTS model, provides confidence that CENTS cases adequately model plant response at EPU conditions.

The CENTS cases modeled the response to many parameters. LAR Table 2.12-4 lists the CENTS cases. Each case provided results for the following parameters: reactor power, reactor coolant system (RCS) temperatures, pressurizer pressure, pressurizer level, steam generator (SG) pressure, SG level, SG steam flow, SG FW flow, steam header pressure, main FW valve position, bypass FW valve position, FW pump pressures (suction and discharge), and FW temperature. Many of these parameters are related to the FW system, and the parameter responses demonstrated acceptable FW system response.

Although step change load transients are not planned, as discussed in LAR Section 2.12.1.2.7, FW system response is monitored during power ascension. The monitoring includes evolutions such as swap from FW bypass to the FW flow control valves, second condensate pump start, second FW pump start, closure of second FW pump recirculation valve, and heater drain (HD) pumps start. These evolutions are FW system transients even though reactor power and load are not expected to change.

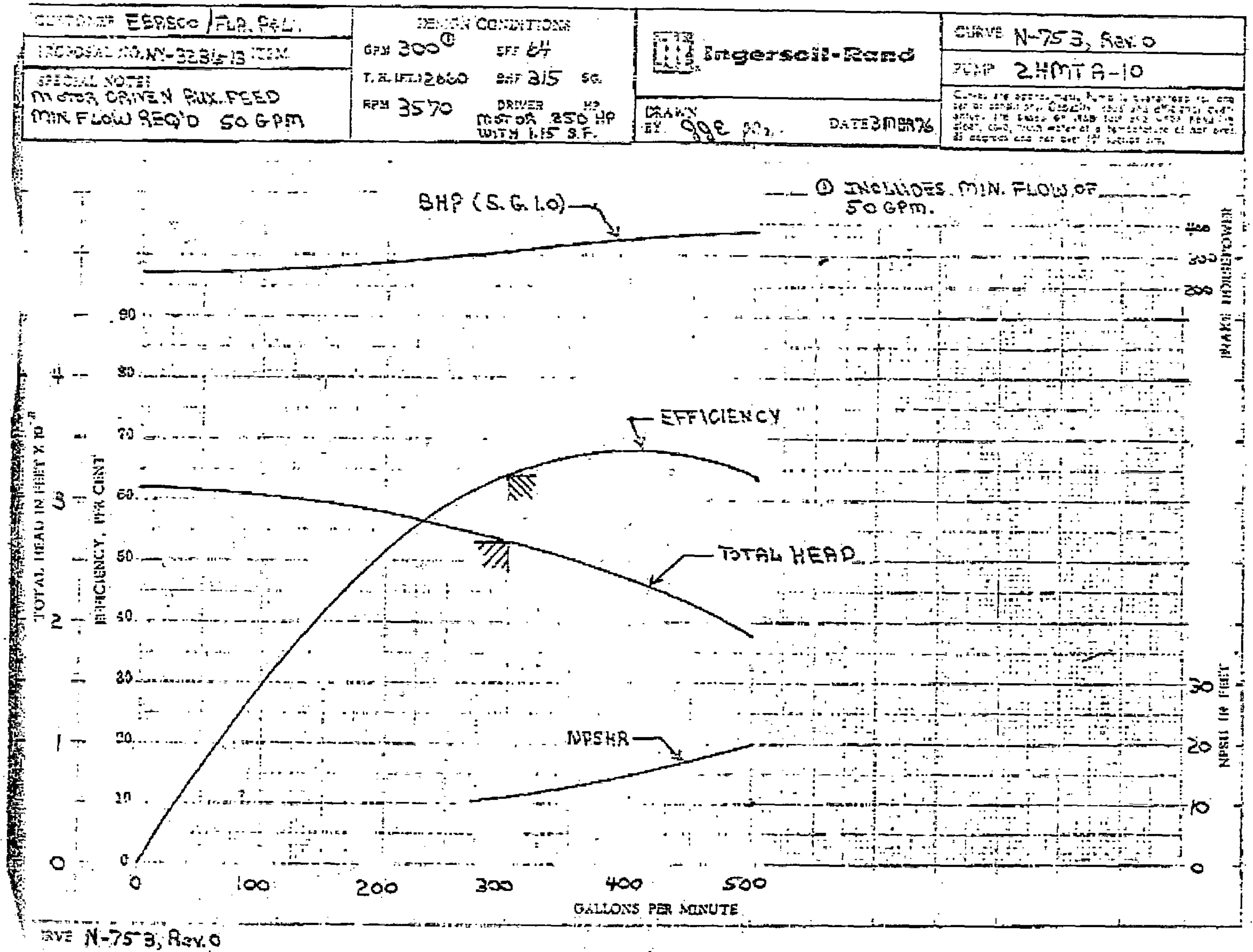

FIGURE SBPB2-1: Manfacturer's Pump Curve For AFW Pumps

REVISION NO.: 3	PROCEDURE TITLE: 2A AUXILIARY FEEDWATER PUMP REFUELING SHUTDOWN PUMP AND VALVE TEST	PAGE: 14 of 14
PROCEDURE NO.: 2-OSP-09.02A	ST. LUCIE UNIT 2	

ATTACHMENT 1
2A Auxiliary Feedwater Pump Comprehensive Flow Test
(Page 1 of 1)

Date: 3/24/11

Inlet Press PI-12-18A temp gauge (psig)	Disch. Press PI-09-7A temp gauge (psig)	Calculated Pump Head (ft.) *	Vibration Instr. No. PSL-2369 — Peak Velocity (in./sec.) ** IPV	IPH	OPV	OPH	OPA
18	1235	2807	.03136	.03685	.03322	.03448	.04177
Acceptance Criteria *** — Allowable Range		2645 to 2928	<0.086	<0.090	<0.081	<0.064	<0.107
Acceptance Criteria *** — Alert Range		2560 to <2645	0.086 to 0.208	0.090 to 0.217	0.081 to 0.195	0.064 to 0.155	0.107 to 0.259
Acceptance Criteria *** — Required Action		<2560 or >2928	>0.208	>0.217	>0.195	>0.155	>0.259

* Calculated Pump Head in feet = (Discharge Pressure – Inlet Pressure) X 2.307.
** **Do not use** the Vibration Probe Triaxial Mounting Block when measuring pump vibration.
*** (Section 8.1.3 Management Directive 1)

> **NOTE**
>
> *Any time a pump is placed in an ALERT or ACTION status, System Performance Group is required to be notified immediately (call out if necessary) for resolution of discrepancies and to coordinate the initiation of corrective action.*

The above data has been compared to the acceptance criteria and determined to be:
☒ Acceptable ☐ Alert Range ☐ Required Action Range

Purpose of Test: ☐ Quarterly Code Run ☒ Post Maintenance (explain) outage work ☒ other SCE Requirement

FIGURE SBPB2-2: AFW Pump 2A Test Results

REVISION NO.: 3	PROCEDURE TITLE:	PAGE:
PROCEDURE NO.: 2-OSP-09.02B	2B AUXILIARY FEEDWATER PUMP REFUELING SHUTDOWN PUMP AND VALVE TEST ST. LUCIE UNIT 2	14 of 14

ATTACHMENT 1
2B AUXILIARY FEEDWATER PUMP COMPREHENSIVE FLOW TEST
(Page 1 of 1)

Date: 3/24/11

Inlet Press PI-12-18B temp gauge (psig)	Disch. Press PI-09-7B temp gauge (psig)	Calculated Pump Head (ft.) *	Vibration Instr. No. PSL-2369				
			Peak Velocity (in./sec.) **				
			IPV	IPH	OPV	OPH	OPA
17.2	1218	2770	.04335	.04964	.03951	.03253	.03897
Acceptance Criteria ***	Allowable Range	2581 to 2857	<0.149	<0.141	<0.166	<0.119	<0.140
	Alert Range	2552 to <2581	0.149 to 0.357	0.141 to 0.338	0.166 to 0.399	0.119 to 0.285	0.140 to 0.337
	Required Action	<2552 or >2857	>0.357	>0.338	>0.399	>0.285	>0.337

* Calculated Pump Head in feet = (Discharge Pressure – Inlet Pressure) X 2.307.
** Do not use the Vibration Probe Triaxial Mounting Block when measuring pump vibration.
*** (Section 8.1.3 Management Directive 1)

> **NOTE**
> Any time a pump is placed in an ALERT or ACTION status, System Performance Group is required to be notified immediately (call out if necessary) for resolution of discrepancies and to coordinate the initiation of corrective action.

The above data has been compared to the acceptance criteria and determined to be:
☒ Acceptable ☐ Alert Range ☐ Required Action Range

Purpose of Test: ☐ Quarterly Code Run ☒ Post Maintenance (explain) Outage Work ☐ other Full Flow Test

FIGURE SBPB2-3: AFW Pump 2B Test Results