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

FPL

September 14, 2004

L-2004-193
10 CFR 50.90

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

RE: St. Lucie Unit 2
Docket No. 50-389
Proposed License Amendment
Request for Additional Information Response
WCAP-9272 Reload Methodology and
Implementing 30% Steam Generator Tube Plugging Limit

By letter L-2003-276 dated December 2, 2003, and pursuant to 10 CFR 50.90, Florida Power & Light Company (FPL) requested to amend Facility Operating License NPF-16 for St. Lucie Unit 2. The purpose of the proposed license amendment is to allow operation of St. Lucie Unit 2 with a reduced reactor coolant system (RCS) flow, corresponding to a steam generator tube plugging level of 30% per steam generator. The re-analysis performed to support this reduction in reactor coolant system (RCS) flow has used Westinghouse WCAP-9272, Westinghouse Reload Safety Evaluation Methodology. The implementation of these changes required changes to the current Technical Specifications (TS).

FPL, Westinghouse, and NRC met on July 19 –20, 2004 to the NRC request for addition information (RAI) dated June 21, 2004. The enclosures to this letter provide the responses to the NRC information requests.

The proposed amendment includes the following Technical Specifications changes: revision to the Thermal Margin Safety Limit Lines TS Figure 2.1-1, reduction in RCS flow in TS Table 3.2-2 and in footnote to TS Table 2.2-1, changes to positive MTC in TS 3.1.1.4, changes to surveillance requirements for Linear Heat Rate TS 3/4.2.1, deletion of Fxy TS 3/4.2.2, relocation to core operating limits report (COLR) of departure from nucleate boiling (DNB) parameters in TS 3.2-5, changes to Design Features Fuel Assemblies TS 5.3.1, deletion of Design Features RCS Volume TS 5.4.2, COLR methodology list update in TS 6.9.1.11b and conforming changes to TS 1.38, TS 3.2.4, TS 3/4.10.2, and TS 6.9.1.11a.

To address expected increases in steam generator tube plugging (SGTP) for the current steam generators, analyses have been performed that support the operation of St. Lucie Unit 2 at 100% of rated thermal power (2700 MWt), with the following conditions:

1. Maximum SGTP of 30% in each of the two steam generators.
2. Maximum tube plugging asymmetry of 7% between the two steam generators.
3. A reduction in the Technical Specifications required minimum RCS flow from the current value of 355,000 gpm to 335,000 gpm.

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

AP01

The analyses are to be implemented for St. Lucie Unit 2 Cycle 15, which is planned to begin operation in December 2004. These analyses involve changes to the reload analysis methodology to improve and streamline the reload process related to cycle-specific physics calculations performed as part of the safety analysis checklist.

Enclosure 1 provides responses to questions that do not contain any proprietary information. Enclosures 2A and 2B, respectively, provide proprietary and nonproprietary versions of the responses to questions that require the submittal of proprietary information. Enclosure 3 contains the attachments supporting information for the responses in Enclosures 1 and 2. Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain proprietary information. Enclosure 2B and Attachments 3B and 4B of Enclosure 3 provide the non proprietary versions. The Westinghouse affidavit requesting that the proprietary information be withheld from public disclosure pursuant to 10 CFR 2.390 and the bases for the request are included as Enclosure 4.

Westinghouse Electric Company, LLC has determined that the information in Enclosure 2A and Attachment 3A and 4A of Enclosure 3 are proprietary in nature. Therefore, it is requested that these documents be withheld from public disclosure in accordance with the provisions of 10 CFR 2.390(a)(4). The Westinghouse reasons for the classification of this information as proprietary and the signed affidavit are included as part of Enclosure 4.

The original determination of No Significant Hazards consideration remains bounding. In accordance with 10 CFR 50.91 (b)(1), a copy of the proposed amendment is being forwarded to the State Designee for the State of Florida.

Approval of this proposed license amendment remains requested by November 2004 to support the reload analyses for St. Lucie Unit 2 Cycle 15. Please issue the amendment to be effective on the date of issuance and to be implemented within 60 days of receipt by FPL. Please contact George Madden at 772-467-7155 if there are any questions about this submittal.

Very truly yours,

William Jefferson, Jr.
Vice President
St. Lucie Plant

WJ/GRM

Enclosures (4)

cc: Mr. William A. Passetti, Florida Department of Health

Enclosure 2A and Attachments 3A and 4A of Enclosure 3
contain 10 CFR 2.390(a)(4) Proprietary Information

STATE OF FLORIDA)
) ss.
COUNTY OF ST. LUCIE)

William Jefferson, Jr. being first duly sworn, deposes and says:

That he is Vice President, St. Lucie Plant, for the Nuclear Division of Florida Power & Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information, and belief, and that he is authorized to execute the document on behalf of said Licensee.

William Jefferson, Jr.

STATE OF FLORIDA

COUNTY OF ST LUCIE

Sworn to and subscribed before me

this 14 day of Sept., 2004
by William Jefferson, Jr., who is personally known to me.

Name of Notary Public - State of Florida

Leslie I. Whitwell
MY COMMISSION # DD028212 EXPIRES
May 12, 2005
BONDED THRU TROY FAIN INSURANCE, INC.

(Print, type or stamp Commissioned Name of Notary Public)

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

Enclosure 1

FPL Non Proprietary

Responses to NRC RAI

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

NRC Request 1:

The Technical Specification (TS) plugging limit for steam generator tubes (typically 40% of the nominal tube wall thickness) is based on minimum tube wall thickness requirements necessary to ensure that stress limits will be maintained within design basis limits for the spectrum of normal operating and accident conditions with allowance for incremental flaw growth between inspections and flaw measurement error. The analyses to determine these minimum wall thickness requirements in support of the TS plugging limit are usually referred to as "Regulatory Guide (RG) 1.121 analyses." (RG 1.121 is entitled, "Bases for Plugging Degraded PWR Steam Generator Tubes.") What impact does the subject license amendment request have on the loads, including differential pressure loads, vibrational loads, and temperatures acting on the tubes during normal operating and accident conditions? What is the impact of these revised loadings on the minimum wall thickness requirements? If there is an impact, discuss whether the technical specification 40% plugging limit continues to provide adequate allowance relative to the minimum wall thickness requirements for incremental flaw growth between inspections and flaw measurement error.

Response 1:

Draft Regulatory Guide 1.121 is not currently part of the licensing basis for St. Lucie Unit 2. Steam generator tube integrity is maintained by adherence to the requirements of NEI 97-06, Revision 1, *Steam Generator Program Guidelines.* This approach is consistent with the RG 1.121 analysis. The steam generator program at St. Lucie Unit 2 incorporates the performance criteria defined therein to ensure the steam generator tubes remain capable of performing their design safety function. Specifically, the structural integrity performance criterion (SIPC) requires the following:

> *Steam generator tubing shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby and cooldown, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal full power operating conditions and a safety factor of 1.4 against burst under the limiting design basis accident. Any additional loading conditions shall be included as required by the existing design and licensing basis.*

Recent meetings between the Industry and NRC have been held to consider changes to the SIPC to address the potential for additional loading conditions. If it is determined that these additional loading conditions significantly affect tube burst or collapse, they must also be considered as part of the tube structural limit calculations. It is anticipated that these additional requirements will be part of NEI 97-06, Revision 2, scheduled to be released later this year.

To ensure the structural integrity performance criterion is satisfied, the St. Lucie 2 steam generator program requires an evaluation of the steam generator tubing each operating cycle. This evaluation includes four specific steps:

- An assessment of the existing degradation mechanisms is performed. Part of this assessment is to establish the structural limits for each degradation mechanism and to determine the flaw growth rate. This assessment also defines the tube inspection technique to be used to detect a specific flaw and the number and location of tubes to be tested.
- Performance of detailed tube inspections. Inspections of steam generator tubing is performed each outage in accordance with EPRI guidelines.
- Once the inspection is complete, an assessment of the steam generator tubing is performed. The purpose of this assessment is to determine if the structural integrity criterion has been satisfied for the previous operating cycle and will continue to be met for the next operating cycle.
- Those tubes that may not satisfy the structural integrity over the next operating cycle are either removed from service or repaired using an approved repair technique (e.g., steam generator sleeving).

It should be noted that while analytical techniques are used to determine if structural integrity requirements are satisfied, they are often overly conservative because they do not model specific flaws accurately. Many times an in-situ pressure test is performed during the outage to make a more accurate assessment of the tube's structural integrity.

Although there is currently no plant-specific calculation that provides the basis for the St. Lucie 2 tube plugging limit, the bounding consideration is 3 times normal operating differential pressure. Using the ASME Code equation for a uniformly thinned tube, the structural limit with 30% tube plugging (secondary pressure of 766 psia) is slightly over 60% through-wall. Thus, the 40% through-wall plugging limit will continue to provide adequate allowance relative to differential pressure considerations.

Bending stress in the tube bundle from seismic and/or loss of coolant accident (LOCA) loads are only significant in the upper bundle region because of the cantilever between the upper partial eggcrate and the upper most elevation of the tube. These accident loads induce a horizontal motion of the tubes that is restrained by the upper partial eggcrate causing a bending stress at that location. Typically, the longest tubes (i.e., Row 140) are most affected by this loading condition.

To determine the impact of this loading condition on a typical Combustion Engineering (CE) steam generator, testing was conducted to measure the movement of a tube during simulated LOCA conditions. This test was also used for verification of the computer code used by CE to calculate blowdown loads. The results are documented in EPRI Report NP-2652, *Loads on Steam Generator Tubes During Simulated Loss-Of-Coolant Accident Conditions*, November 1982). They showed that the upper bundle support structure would not allow tube movement during the test. Thus, bending stresses from LOCA plus seismic condition are not significant and will not have an impact on the 40% tube plugging limit.

The only other faulted condition that could result in significant bending stresses on the tubes is the main steam line break (SLB) plus seismic condition. As shown in the ASME Code design report for the St. Lucie 2 steam generators, the worst case SLB occurs during zero power conditions. If the accident is initiated at full power conditions, the gap between the upper tube supports and the I-beams closes thereby transferring much of the bending load from the tubes to the I-beams. At zero power conditions, the gap is larger and does not completely close during the accident. However, even in this case, the calculated bending stress is less than one-third of the allowable value. Since 30% tube plugging will not significantly affect zero power conditions nor will it affect the gap between the tube supports and the I-beams, the SLB plus seismic condition will not have an impact on the 40% tube plugging limit. Other faulted conditions (e.g., feedwater line break) do not cause significant bending stresses on the tubes.

A review of the St. Lucie 2 steam generator design specification and ASME Code design report was performed to determine the highest ΔP during normal operating transients. Of 44 transient conditions evaluated, the highest ΔP occurred four hours into plant heatup when the primary side was at 2250 psia and the secondary system was at 520 psia. Using average values of the lower tolerance limit (LTL) for 48-mil wall CE tubing from the EPRI Flaw Handbook, yield at this ΔP would occur when a tube was uniformly thinned to a wall thickness of 17 mils or about 64% degradation. Since the heatup condition is not affected by tube plugging, this loading condition will not affect the 40% tube plugging limit.

Thermal loads on the tubes as determined in the original ASME Code design report were based on the ΔT between the primary inlet and outlet temperatures as well as ΔT between the primary inlet temperature and the secondary saturation temperature. At 30% tube plugging, the ΔT between the primary inlet and outlet is 55.4°F, which is lower than the 58°F evaluated in the original stress report. The ΔT between the primary inlet temperature and the secondary saturation temperature is essentially the same for both conditions (89.6°F in the original stress report and 89.7°F for 30% tube plugging). Thus, 30% tube plugging will not have a significant effect on thermal loads and the 40% tube plugging limit will be unaffected by this loading condition.

The only loading condition not specifically addressed by the St. Lucie Unit 2 steam generator program when evaluating structural integrity is the potential for fluid-elastic instability. Plugging of up to 30% of the steam generator tubes will cause a change in the secondary flow fields. Westinghouse performed a detailed evaluation of the fluid conditions in the steam generator assuming 30% of the tubes were plugged. These conditions were then used to evaluate the impact on steam generator tubes that were in-service, sleeved, plugged and stabilized. In all cases, there was no fluid-elastic instability and root mean square (RMS) displacements at the mid-span of the tube remained below 10 mils. With no fluid-elastic instability and only small mid-span displacements, there will be no significant change in previously observed wear rates or high-cycle fatigue. Note that it is possible that different wear patterns in the tube bundle could emerge; however, the wear rates should not be affected. Hence, vibration loads associated with 30% tube plugging will not be significant and will not affect the 40% tube plugging limit

NRC Request 2:

What design bases parameters, assumptions or methodologies (other than those provided in the December 2, 2003 submittal) were changed in the radiological design basis accident analyses as a result of the proposed change? If there are many changes it would be helpful to compare and contrast them in a table. Also, please provide a justification for any changes.

Response 2:

Enclosure 3 Attachment 1 presents a comparison of the input and assumption differences between the L-2003-220 Alternative Source Term submittal steam generator tube rupture (SGTR) dose analyses and the L-2003-276 Steam Generator Tube Plugging submittal SGTR dose analyses. Both analyses include the proposed Technical Specification revision to the reactor coolant system (RCS) operational leakage limits, stated in Limiting Condition for Operation (LCO) 3.4.6.2, RCS Operational Leakage, for total primary-to-secondary leakage through all steam generators (reduced from 1 gpm to 0.3 gpm) and the limit specified for primary-to-secondary leakage through any one steam generator (reduced from 720 gallons per day to 216 gallons per day). There are no other radiological design bases parameters and assumptions changes due to the proposed tube plugging change.

NRC Request 3:

Section 4.6 of Reference 2, states that the methodology and analysis assumptions presented in L-2003-220 (dated September 18, 2003, "Alternate Source Term Methodology and Conforming Amendments") remain applicable to the 30% Steam Generator Tube Plugging (SGTP) analysis. What radiological dose consequence analysis parameters are impacted by the proposed change? Please provide the value of the parameters impacted and justification why the methodology and assumptions in L-2003-220 are not impacted.

Response 3:

Enclosure 3 Attachment 1 presents a comparison of the input and assumption differences between the L-2003-220 Alternative Source Term submittal SGTR dose analyses and the L-2003-276 Steam Generator Tube Plugging submittal SGTR dose analyses. The methodology, inputs, and assumptions used in the L-2003-220 submittal for all other dose events are not impacted by the proposed change in L-2003-276 as these inputs and assumptions were already established to bound the 30% SGTP conditions.

NRC Request 4:

Section 4.6 of Reference 2 states the dose calculations for the Steam Generator Tube Rupture (SGTR) are redone using the same methods and assumptions (as L-2003-220) except for the steam release information from the two steam generators. What is the reactor coolant system mass assumed for each accident described in Section 4.6?

Response 4:

All of the iodine spike analyses begin with the dose equivalent Iodine-131 concentration (per unit mass) requirements of Technical Specifications for the RCS. For the pre-accident iodine spike SGTR case, the maximum RCS mass (475,385 lb_m) is used with isotopic concentrations based on the Technical Specification RCS activity concentration limit to maximize the activity available for release. For the concurrent iodine spike SGTR case, the RCS mass used in the determination of the RCS activity (adjusted to the Technical Specification RCS activity concentration limit) and in the design basis of the letdown system (452,000 lb_m) is used to assure that the iodine appearance rates have a consistent basis with the Technical Specification limit and RCS activity on which they are based.

The 30% SGTP conditions for RCS mass were already considered in the Alternative Source Term submittal where appropriate and conservative. The RCS mass values documented in L-2003-220 are therefore applicable to the events/accidents described in Section 4.6.

NRC Request 5:

L-2003-220 contains the parameters and assumptions used for the calculation of the SGTR accident. For the SGTP amendment please provide the same information as contained in Tables 2.4-1 through Table 2.4-5 of L-2003-220. Please specify the break flow flashing fraction and the break flow mass in the ruptured steam generator.

Response 5:

Enclosure 3 Attachment 1 presents a comparison of the input and assumption differences between the L-2003-220 Alternative Source Term submittal SGTR dose analyses and the L-2003-276 Steam Generator Tube Plugging submittal SGTR dose analyses.

NRC Request 6.a. Nuclear Design:

Section 3.1 of Reference 3 indicates that the Westinghouse nuclear design models and methods are used for the St. Lucie Unit 2 nuclear design. Justify that the Westinghouse methods, documented in [WCAP-11569] [sic] for PHOENIX-P/ANC, WCAP-10965 for ANC and WCAP-10216 for the relaxation of control axial offset control, are applicable for use in the nuclear design for St. Lucie Unit 2 including the Combustion Engineering (CE) fuel design with ZIRLO cladding.

Response 6.a:

Topical Report NF-TR-95-01, Supplement 1 (Reference 11) was submitted to the NRC in December 1997 as part of the implementation of COLR for St. Lucie Unit 2. WCAP-

11596-P-A is specifically identified in NF-TR-95-01, and is listed as Item 1 in the list of approved methods in TS 6.9.1.11. While WCAP-10965 is not called out explicitly, it is enveloped as a cascading reference via WCAP-11596-P-A. The COLR submittal was approved by the NRC in Amendment No. 92 in July 1998. On page 3 of the Safety Evaluation for Amendment No. 92, the NRC states:

> *"The list of documents in TS 6.9.1.11 describing the acceptable FPL analytical methods includes topical report NF-TR-95-01, ...Since NF-TR-95-01 did not include any benchmark data for St. Lucie Unit 2, FPL included Supplement 1 (August 1997) as an attachment to this COLR request. This supplement provides comparisons of the results of calculations performed by FPL using the methodology described in NF-TR-95-01 with operating data from St. Lucie Unit 2. The staff has reviewed the comparisons ...We conclude that the good agreement between the predictions and the measurements reported demonstrates FPL's capability to apply the Westinghouse licensed methodology presented in NF-TR-95-01 to perform reload core design for St. Lucie Unit 2..."*

FPL has performed nuclear design and reload calculations using these methods and physics tools for St. Lucie Unit 2 since 1999. The continued use of these methods is explicitly cited in Attachment 1 of the original submittal, "ANC/PHOENIX (WCAP-11596-P-A) code package, currently in use for St. Lucie Unit 2, continues to be the neutronics analysis methodology."

The licensing standing of WCAP-10216-P-A for use in the nuclear design for St. Lucie Unit 2, including the CE fuel design with ZIRLO™ cladding is discussed in the responses to Nuclear Design RAIs 6.b and 6.c, below.

NRC Request 6.b. Nuclear Design:

Please provide verification (documentation, such as an SE) that the Westinghouse Relaxed Axial Offset Control (RAOC) Methodology was also approved for non-Westinghouse plants.

Response 6.b:

Topical reports WCAP-10216-P-A (including the enclosed SER) and WCAP-10216-P-A, Revision 1A (including the enclosed SER) clearly state methods as they apply to Westinghouse plants. This amendment request submittal (Reference 1) provides the basis to extend the application to St. Lucie Unit 2 using CE fuel design with or without the ZIRLO™ cladding. The use of ZIRLO™ cladding for CE fuel design has previously been approved in CENPD-404-P-A.

Additional information supporting the application of RAOC for St. Lucie Unit 2 is included in the response to RAI Nuclear Design 6.c, below.

NRC Request 6.c. Nuclear Design:

Standard Westinghouse nuclear design models and methods were approved for applicability to the Westinghouse plants only. No non-Westinghouse plant data was provided with the Westinghouse nuclear design analytical models and methods. Consequently, these nuclear models cannot be applied to non-Westinghouse plants. Please provide quantitative technical justification (pertinent non-Westinghouse data) in support of validating the RAOC methodology for non-Westinghouse plants.

Response 6.c:

As stated in the response to Nuclear Design RAI 6.a, the Westinghouse nuclear design methods were specifically approved to perform reload core designs for St. Lucie Unit 2 in Amendment No. 92. Regarding the NRC request for "quantitative technical justification (pertinent non-Westinghouse data) in support of validating the RAOC methodology for non-Westinghouse plants," it is not the intent of this submittal to seek generic approval for the application of RAOC methodology to CE plants. As indicated in the response to Nuclear Design RAI 6.b, this submittal (Reference 1) provides the basis to extend the application to St. Lucie Unit 2 only.

The Westinghouse relaxed axial offset control (RAOC) methodology (WCAP-10216-P-A) is used to evaluate axial power distributions. RAOC methods are well known and used extensively for Westinghouse plants. In extending the application to St. Lucie Unit 2, FPL and Westinghouse have provided information throughout the submittal to support this extended application.

Application of RAOC is identified as one of the "several methodology changes implemented in the revised reload analyses" in L-2003-276 (Reference 1).

The RAOC topical report, WCAP-10216-P-A, is identified as Item 5 under "Application of Methodologies Not Previously Approved for Application to St. Lucie Unit 2" in Attachment 1 of the original submittal. It is included in the summary table of methodologies used for St. Lucie Unit 2 analyses presented in Section 1 of Attachment 6 of the original submittal, and the conditional requirements for the use of the RAOC methodology pursuant to the previous approval for Westinghouse plants are addressed in Appendix B of Attachment 6 of the original submittal.

In the years since the development of RAOC, CE plants have undergone similar changes in establishing relaxation of operational margins with respect to allowable axial power distributions. The key technical considerations in the application of RAOC are a clear understanding of the operating definitions and practices, and appropriately defined Technical Specifications to ensure that surveillance tests and limits preserve the validity of the safety analyses.

Operating definitions and practices were carefully defined to establish the key assumptions and confirm data used in the RAOC modeling. While the COLR limits for the departure from nucleate boiling (DNB) LCO and linear heat rate (LHR) LCO appear to be similar in form to the "doghouse" axial flux difference (AFD) limits employed at Westinghouse plants (where the DNB and LHR limits are coincident), the basis (Axial Shape Index vs. Axial Flux Difference) for the limiting conditions of operation differ from those normally applied in the RAOC application; this difference leads to a non-linear expression of axial power distribution limits modeled in RAOC. The application of the RAOC analysis is presented in Appendix A of Attachment 6 of the original submittal, and provides additional clarification on this unique modeling consideration. Additional information is also provided in the response to Nuclear Design RAI 6.f.

Technical Specification (TS) and COLR limits were defined with direct consideration of the surveillance considerations outlined in the RAOC topical reports, taking into account the possibility that $F_Q(z)$ may increase between surveillance tests. Some minor variations from the typical RAOC specification were included for consistency with CE definitions and formats. Attachments 3 and 4 of L-2003-276 contain information on the TS and COLR changes for the 30% Steam Generator Tube Plugging program through which the initial introduction of RAOC for St. Lucie Unit 2 has been presented. Attachment 3 of L-2003-276 contains marked up copies of the proposed TS changes. Attachment 4 of L-2003-276 contains information copies of the proposed changes to the TS Bases and Core Operating Limits Report (COLR).

Additional supporting information on the application of RAOC to St. Lucie Unit 2 is also included in the responses to other RAIs (Nuclear Design RAI 6.a, 6.b and 6.f).

NRC Request 6.d. Nuclear Design:

In Section 3.4, reference is made to "baseline neutronics," "adjusted only slightly," "preclude violations," resulting in challenges to analysis margins. What do these mean?

Response 6.d:

This section refers to the identification of the values assumed for key physics parameters used in the safety analyses. For the WCAP-9272 reload methodology, plant-specific safety analyses are performed in a conservative manner to allow them to be applied over a number of cycles. To permit this, discretionary conservatisms are included in the safety analysis input for the key physics parameters to conservatively bound the conditions expected over several cycles, including any known, planned, or anticipated changes in fuel management or plant operation. An evaluation of the key physics parameters is undertaken on a cycle-by-cycle basis as part of the WCAP-9272 reload process. The purpose of this evaluation is to determine if the values of the key parameters assumed in the safety analyses (including LOCA) are conservative when compared to the plant-specific, cycle-specific design values. In this way, the safety analyses are confirmed to remain "bounding" with respect to the reload design. Should any of the key parameters be determined to be more severe than the safety analysis, a "violation" is identified for that parameter. In such a case, evaluations and/or analyses would be performed to either adjust the reload design to return within the safety analysis limits and/or the safety analysis would be evaluated or reanalyzed to assure applicable criteria would be satisfied (all violations must be reconciled). The likelihood of encountering a violation during the reload evaluation is tied in large part to the values of the key physics parameters assumed in the safety analysis and the degree of conservatism applied. Selections of very conservative values will lead to a very limited possibility of encountering violations in future reload evaluations. However, addition of large amounts of discretionary conservatism also introduces the possibility that results of the safety analyses will not satisfy the acceptance criteria (DNBR, PCT, etc.) for any given event (i.e., resulting in challenges to analysis margins). The objective then is to select values for the key physics parameters that represent a balance between the likelihood of violations in the reload evaluation and the requirements to satisfy the various acceptance criteria for the safety analyses. This set of values, termed the "baseline neutronics," would then represent the master list of physics input data for the safety analyses. Historically, the baseline neutronics (called a Safety Analysis Checklist or SAC for Westinghouse plants) has been established based on the extensive Westinghouse experience base, adjusted as needed to account for new products or operating strategies (low leakage loading patterns, new burnable absorbers, etc.). With this starting point, detailed reviews were undertaken to look at:

- the unique features of St. Lucie Unit 2 versus a standard Westinghouse plant (large guide tubes, different TS definitions, etc),
- measured data for several recent St. Lucie Unit 2 operating cycles, and
- anticipated plant changes (reduced flow, transition to ZIRLO™ cladding, etc.).

The results of these reviews were applied to the values of the key physics parameters to establish a set of "baseline neutronics" appropriate for application to St. Lucie Unit 2. As a matter of interest, the values of the key physics parameters remained unchanged or were "adjusted only slightly" from the representative Westinghouse values. This process yielded the final definition of the St. Lucie Unit 2 "baseline neutronics" which served as the initial basis for the safety analysis inputs for the key physics parameters.

NRC Request 6.e. Nuclear Design:

Table 3-1 provides the key safety parameters ranges, but no technical basis is provided to support the changes, particularly, the increase in the Moderator Temperature Coefficient (MTC) from the current value of +3 to +5 up to 70% power. Please provide quantitative and qualitative basis for this change.

Response 6.e:

As noted in Table 3-1 of the Licensing Report (Reference 3), the Moderator Temperature Coefficient (MTC) up to 70% of Rated Thermal Power (RTP) remains unchanged from the current design basis value of +5 pcm/°F. Above 70% of Rated Thermal Power the value has been changed from the current design basis value of +3 pcm/°F up to 100% of RTP to ramping from +5 pcm/°F to 0 pcm/°F at 100% of RTP. Thus, the MTC for full power operation has been reduced from +3 pcm/°F to 0 pcm/°F.

To support the proposed design values for the MTC, transients analyzed at part-power conditions (that is, less than 70% power) were analyzed with a +5 pcm/°F MTC and for full power transients, a 0 pcm/°F MTC was assumed, as described in Section 5 of the Licensing Report (Reference 3). The results of the analyses presented in Section 5 of the Licensing Report (Reference 3) provide the quantitative basis for the "change" in the MTC.

NRC Request 6.f. Nuclear Design:

The first paragraph on page 3-3 does not adequately discuss the six bullets provided in Section 3.6. Please provide detail quantitative and qualitative technical justification for each one of these bullets, in particular, the subject of non-linear relationship for axial flux and the elimination of the positive MTC. What is a part power multiplier?

Response 6.f:

The first bullet identifies the reduction in the value for the allowed peak linear heat rate (COLR Figure 3.2-1) as one of the technical specification/COLR changes that impacts the nuclear design. As noted in the first paragraph on page 3-3, the reduction in the peak linear heat rate was a result of the large break loss-of-coolant accident (LOCA) emergency core cooling system (ECCS) performance analysis. The large break LOCA analysis is described in Section 5.2.3 of the Licensing Report for the 30% SGTP proposed license amendment (Reference 3). The reduction in the value for the peak linear heat rate from 13.0 kW/ft to 12.5 kW/ft was one of several significant changes to the large break LOCA analysis. The reduction in the peak linear heat rate and the implementation of the 1999 EM version of the large break LOCA evaluation model were two significant beneficial changes that were implemented to offset the impact of two adverse changes, namely, the increase in the number of plugged steam generator tubes and a correction to the reactor coolant pump locked rotor k-factor. The NRC was previously notified of the correction to the reactor coolant pump locked rotor k-factor and its impact on the current large break LOCA analysis in Reference 6.

The second bullet relates to the use of a part power multiplier for Fr. As with all Westinghouse-analyzed plants, for St Lucie Unit 2 the limit on Fr is expressed as a function of core average power. The Fr limit increases as core power decreases. The relationship is given in the following equation:

$$\text{Fr limit} = 1.70 \times [1 + 0.4(1-P)]$$

Where P is the core relative power and the 0.4 is the part power multiplier.

The use of the part power multiplier allows for the increase in Fr, which is generally seen when the core power is reduced and control rods inserted. The above equation is used in the Thermal Hydraulic analysis to generate the Core Thermal Limits used in the modeling of the non-LOCA safety analyses to show that the DNBR requirements remain satisfied.

The third bullet discusses the reduction in COLR linear heat rate when operating on the excore detector monitoring system (EDMS). Both the DNBR limit and the LHR limit of 12.5 kW/ft must be observed during Condition I operation at all times. The DNBR is not monitored directly and so is shown to be met analytically by use of the RAOC analysis, which is performed for each cycle. The RAOC analysis uses the ASI versus power operating band(s) given in the COLR. RAOC studies have shown that the DNBR limit will be met using the existing DNB LCO ASI band (Fig 3.2-4 in the COLR). This will need to be confirmed each cycle. Similar studies have shown however that the LHR limit is not likely to be met in the RAOC analysis using the DNB LCO ASI band (values around 13.0 kW/ft would be expected). However, when the plant is operating on the incore detector monitoring system (IDMS), which is the normal mode of operation, the LHR is monitored directly, therefore the operator can take action to avoid violating the LHR limit (e.g. by use of control rods or by reducing power). However, if the plant is operating only on EDMS, the operator does not have this luxury of direct LHR measurement and so reverts to using results from the analytical (RAOC) analysis (see discussion on W(z) factors, below). A more restrictive LHR LCO ASI band is set which the RAOC analysis shows gives acceptable results. This LHR LCO ASI band must then be used when the plant is operating solely on EDMS.

The fourth bullet addresses F_{XY} surveillance. F_{XY} surveillance is a legacy of the days when core predictions and measurement were limited to two-dimensions. With the modern capability to monitor the LHR in 3D via the IDMS (and with the capability to predict 3D transient core behavior and conservatively allow for predicted 3D transient effects when operating only on EDMS) the use of F_{XY} surveillance is redundant. For this reason, F_{XY} surveillance has been eliminated from the Technical Specification requirements, crediting direct LHR surveillance when on IDMS and application of W(z) factors when solely on EDMS.

The fifth bullet describes EDMS LHR surveillance and application of W(z) factors. As described above, when operating solely on EDMS the LHR is not measured directly. During this period, the operator uses results of the analytical power maneuvers as modeled in the (RAOC) analysis to "measure" the bounding LHR at any given time. The RAOC analysis involves performing a very large number of transient simulations consistent with the plant operating within the appropriate ASI band (in this case, the LHR LCO ASI band). This analysis generates constants, which are the ratio of maximum transient LHR to the steady state LHR as a function of core height and core average burnup. As per the proposed Technical Specifications, when solely on EDMS, the operator will apply the W(z) factors to the last steady state LHR map taken to determine conservatively the maximum LHR. This yields the bounding peak LHR as a function of core height. The peak is then compared to the 12.5 kW/ft limit.

(It should be noted that the LHR determined using the W(z) factors is conservative since the W(z) factors assume the most extreme transient conditions allowed by the ASI band; in reality the maximum LHR is likely much less than that predicted.)

The sixth bullet addresses elimination of full power positive MTC. This topic is addressed in item e of this question, above.

In addition to each of the six bullets, the following information is provided to supplement the discussion on the non-linear relationship for axial flux. The definition of the band used to control the axial power distribution at St Lucie Unit 2 is different from that used in standard Westinghouse plants. Although the shape of the curve (which resembles a "doghouse") is similar, the two quantities represented are not the same. At St. Lucie Unit 2, the band defines Axial Shape Index (ASI) as a function of core average power; in standard Westinghouse plants, the band defines Axial Flux Difference (AFD) as a function of core average power.

ASI and AFD are related as follows:

ASI = - AFD/[Core Relative Power x 100]

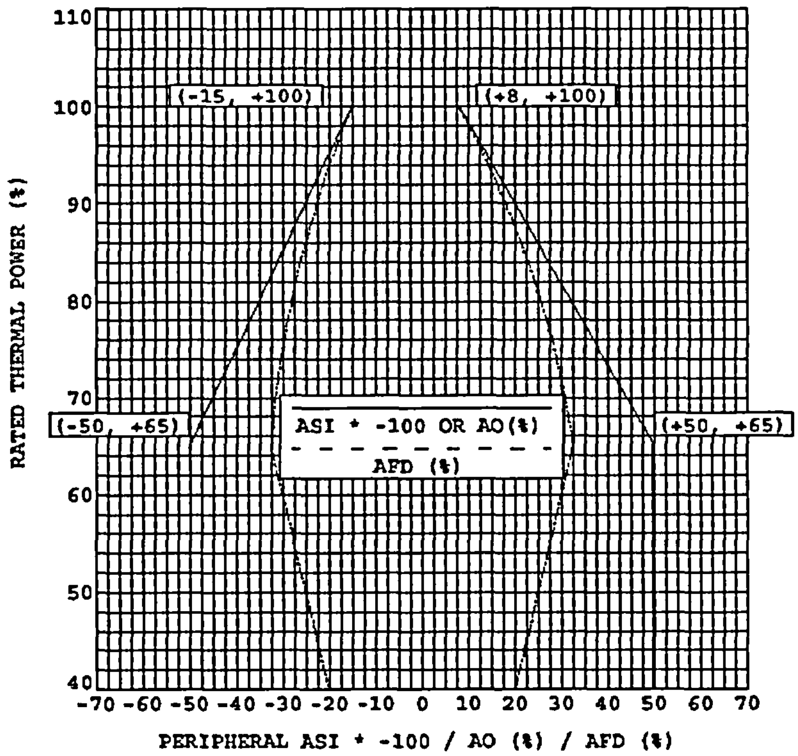
AFD is defined essentially as the excore detector power in the top half of the core minus that in the bottom half of the core.

The band can easily be transposed from one definition to the other using the above equation. The RAOC analysis that calculates the peak LHR uses, as input, the band in terms of AFD, rather than ASI.

The following figure shows an example of a St. Lucie Unit 2 band in terms of both ASI and AFD. As can be seen, the ASI band has linear segments whereas the AFD band is non-linear.

FIGURE 2

ST LUCIE UNIT 2 CYCLE 13
AO and AFD BAND COMPARISON
NO ASI UNCERTAINTY APPLIED

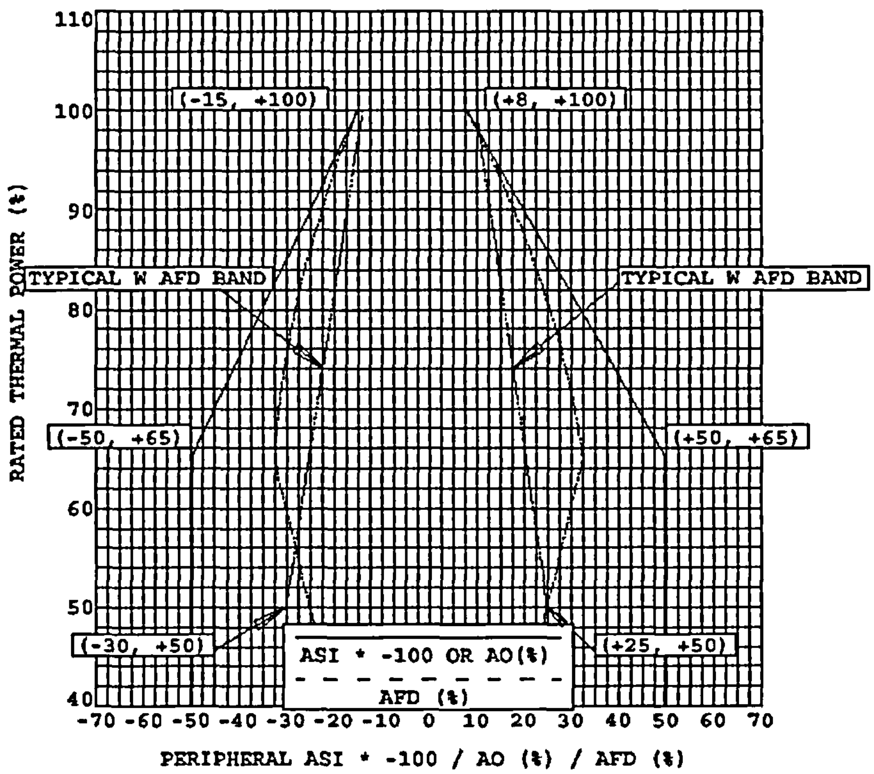


Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

The following figure shows the same bands as above, along with a typical standard Westinghouse band. This figure shows how the standard Westinghouse band is linear in AFD.

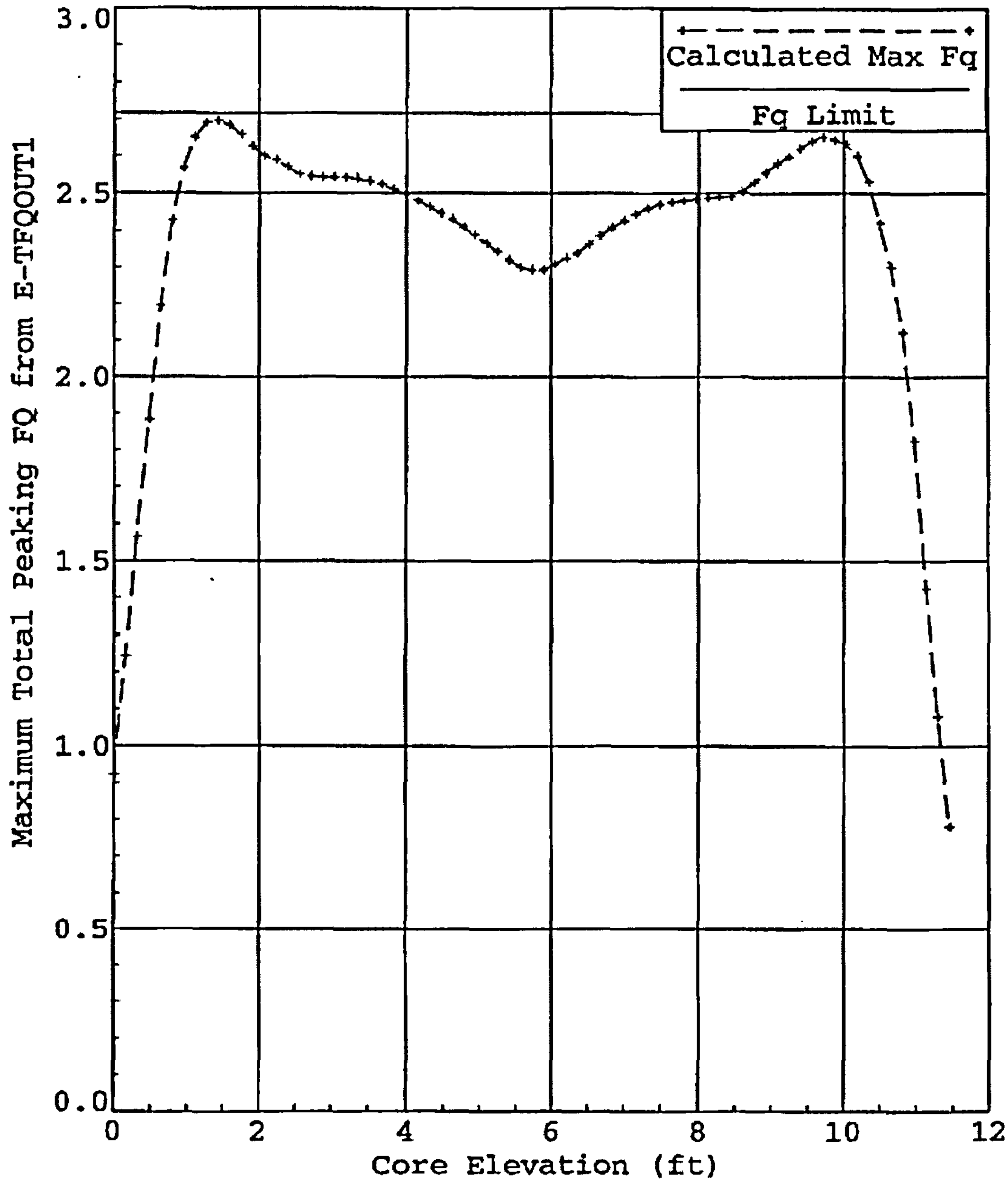
FIGURE 4

ST LUCIE UNIT 2 CYCLE 13
AO and AFD BAND COMPARISON
NO ASI UNCERTAINTY APPLIED



The St. Lucie Unit 2 band is at its widest at 65% power. This allows high LHR values due to the large width of the band in the 65%-70% power range. In order to meet the 12.5 kW/ft value when operating solely on EDMS, the ASI band wings (and associated AFD band non-linear "curves") are narrowed to reduce the predicted peak LHR to below 12.5 kW/ft (conservatively).

Sample of Maximum Calculated Fq from Cycle 15 RAOC Analysis



NRC Request 7. Thermal-Hydraulic Design:

Section 4.2 of Reference 3 indicates that the W-3 correlation and the standard thermal design procedure are used to calculate Departure from Nucleate Boiling Ratios (DNBRs) when the ABB-NV DNB correlation and revised thermal design procedure are not applicable. Identify the non-LOCA events that use the W-3 correlation in the DNBR analysis, and discuss the computer code with the W-3 correlation used for the core thermal-hydraulic analysis. Justify that the W-3 correlation and the associated DNBR safety limit are acceptable for the St. Lucie Unit 2 DNBR calculations.

Response 7:

The W-3 DNB correlation is used with the Westinghouse version of the VIPRE-01 (VIPRE) code in the DNB analysis of the post-trip Hot Zero Power (HZP) steamline break (SLB) event, due to the low core pressure at the limiting DNBR time step. The current NRC-approved W-3 95/95 DNBR limit of 1.45 in the pressure range between 500 and 1000 psia (Reference 8) remains conservative for the St. Lucie Unit 2 application. All other non-LOCA DNB events use the ABB-NV DNB correlation (the DNB-limiting statepoints are within the correlation range).

The W-3 correlation in the VIPRE code has been verified by the code developer, code users including Westinghouse, and by the NRC through audit calculations during the review of the VIPRE code (Reference 9). The W-3 DNB correlation in the Westinghouse version of the VIPRE code remains the same as in the original version of VIPRE.

The W-3 correlation has been applied to all Westinghouse fuel designs, including fuel designs for CE-designed PWRs (Reference 10). Reference 8 documents qualification of the W-3 DNB correlation for HZP SLB application. Additional DNBR margin is also retained in the W-3 DNBR safety analysis of the St. Lucie Unit 2 HZP SLB event in the form of a DNBR multiplier.

NRC Request 8.a: See Enclosure 2A

NRC Request 8.b. Non-LOCA Transients
List the single failure events that are considered in the St. Lucie Unit 2 reload analysis. Identify the limiting single failure and provide the rationale for determination of the limiting single failure for each analyzed event.

Response 8.b:

The following table presents the limiting single failures for each of the events analyzed and presented in Section 5 of the Licensing Report. The events are presented consistent with how the events are listed in Licensing Report Table 5.1.0-2 "Summary of Initial Conditions and Computer Codes".

Single Failures Assumed in the Safety Analyses

Event	Single Failure
15.1 Increase in Heat Removal by the Secondary System	
Decrease in Feedwater Temperature	Failure of one protection train
Increase in Feedwater Flow	Failure of one protection train (Also see response to RAI #12)
Excessive Increase in Main Steam Flow	NA - Bounded by other events
Inadvertent Opening of an SG Relief or Safety Valve	NA - Bounded by other events
Pre-Trip Steamline Break	Failure of one protection train
Post-Trip Steamline Break	Failure of one protection train and one high pressure safety injection train
15.2 Decrease in Heat Removal by the Secondary System	
Loss of Condenser Vacuum	Failure of one protection train
Loss of Non-Emergency AC to the Station Auxiliaries	Not Analyzed - Bounded by other events
Loss of Normal Feedwater	Not Analyzed - Bounded by other events
Feedwater System Pipe Rupture	Failure of one protection train
Asymmetric Steam Generator Transient	Failure of one protection train
15.3 Decrease in RCS Flow Rate	
Partial / Complete Loss of Forced Flow	Failure of one protection train
Reactor Coolant Pump Seized	Failure of one protection train
15.4 Reactivity and Power Distribution Anomalies	
Uncontrolled CEA Bank Withdrawal from Subcritical	Failure of one protection train
Uncontrolled CEA Bank Withdrawal at Power	Failure of one protection train
CEA Misoperation (Dropped Rod)	Failure of one protection train for cases which would result in reactor trip. Not applicable to cases which transition to a new steady-state power level.
Startup of an Inactive Loop at an Incorrect Temperature	NA - Precluded by Tech Specs
CEA Ejection	Failure of one protection train
15.5 Increase in Coolant Inventory	
Inadvertent ECCS Operation at Power	Not Analyzed - Precluded by SIS design
CVCS Malfunction	Complete closure of the letdown control valve.
15.6 Decrease in Coolant Inventory	
Inadvertent RCS Depressurization	Failure of one protection train
Steam Generator Tube Rupture	NA
LOCAs	Failure of an Emergency Diesel Generator

Generally, as noted above, the single most limiting failure for the non-LOCA events is a failure of one protection train as most of the non-LOCA events are terminated by a reactor trip. This failure does not affect the results. For events analyzed beyond the time of reactor trip, sensitivities are run to determine the most limiting failure, such as the loss of one train of the Safety Injection system.

NRC Request 8.c. Non-LOCA Transients

Provide values of opening setpoints of pressurizer safety and main steam safety valves that are credited in the reload analysis. Discuss the determination of the valves' lifting setpoints with inclusion of the positive or negative uncertainty tolerances for each event and justify that the values used in the analysis are consistent with the TS required valves setpoints.

Response 8.c:

Pressurizer Safety Valves (PSV): St. Lucie Unit 2 has three pressurizer safety valves, each with a design pressure of 2500 psia. The valve opening characteristics assumed in a non-LOCA transient analysis depends on the acceptance criterion of interest. For transient analyses in which the reactor coolant system (RCS) overpressurization acceptance criterion is of interest, the opening pressure of the PSVs is maximized by assuming the most positive tolerance of +3%. In contrast, for transient analyses in which the DNBR acceptance criterion is of interest, the opening pressure of the PSVs is minimized by assuming the most negative tolerance of -3%.

As shown below, the PSV modeling is conservative with respect to the Technical Specifications.

Primary Safety Valve Opening Pressures

	Negative Tolerance	Positive Tolerance
Opening Pressure - Analysis Value	2425.45 psia	2574.6 psia
Technical Specification 3.4.2.2	2435.3 psig to 2535.3 psig	

Main Steam Safety Valves (MSSV): The opening tolerance was maximized for the modeling of the two banks of main steam safety valves with different opening setpoints. The limiting consideration for the tolerances is the pressure drop from the steam generator to the inlet of the main steam safety valves. With all of the secondary safety valves open, a pressure drop of 36.1 psid is created due to the steam flow. To maintain a pressure of ≤ 1100 psia (110% of the design pressure) in the steam generators with all of the MSSVs open, the pressure at the main steam safety valve inlet is required to be ≤ 1063.9 psia. This provides a conservative basis for which all valves must be open.

Since the main steam safety valve opening pressure in the model is based on the steam line pressure, the pressure drop between the steam piping and the inlet of the safety valves had to be accounted for. With all main steam safety valves open, a 9.96 psi pressure drop in the main steam safety valve branch lines exists. This is addressed in the analysis by reducing the effective safety valve flow area for the branch line pressure drop.

The steam generator tube rupture event uses a negative tolerance on the main steam safety valve lift pressures of 970 psia (955.3 psig plus 14.7 psi for atmospheric pressure).

The following MSSV modeling approach was conservatively used in all of the non-LOCA safety analyses and is conservative with respect to the Technical Specifications.

Main Steam Safety Valve Pressures

	1st Bank of Valves	2nd Bank of Valves
MSSV Opening Analysis Value	**1058.8 psia**	**1063.9 psia**
Technical Specification Table 3.7-2	**955.3 psig to 995.3 psig**	**994.1 psig to 1035.7 psig**

In response to an NRC follow-up question, the following table summarizes where the safety valves operate for the various non-LOCA events.

Safety Valve Actuation

Event	**Pressurizer Safety Valves Actuate**	**Main Steam System Safety Valves Actuate**
15.1 Increase in Heat Removal by the Secondary System		
Decrease in Feedwater Temperature	No	No
Increase in Feedwater Flow	No	No
Excessive Increase in Main Steam Flow	NA – Bounded by other events	
Inadvertent Opening of an SG Relief or Safety Valve	NA – Bounded by other events	
Pre-Trip Steamline Break	No	No
Post-Trip Steamline Break	No	No
15.2 Decrease in Heat Removal by the Secondary System		
Loss of Condenser Vacuum	Yes	Yes
Loss of Non-Emergency AC to the Station Auxiliaries	Not Analyzed – Bounded by other events	
Loss of Normal Feedwater	Not Analyzed – Bounded by other events	
Feedwater System Pipe Rupture	Yes	Yes
Asymmetric Steam Generator Transient	No	Yes

Event	Pressurizer Safety Valves Actuate	Main Steam System Safety Valves Actuate
15.3 Decrease in RCS Flow Rate		
Partial / Complete Loss of Forced Flow	No	No
Reactor Coolant Pump Seized	No	Yes
15.4 Reactivity and Power Distribution Anomalies		
Uncontrolled CEA Bank Withdrawal from Subcritical	NA – safety valves not modeled	
Uncontrolled CEA Bank Withdrawal at Power	No	Yes
CEA Misoperation (Dropped Rod)	No	No
Startup of an Inactive Loop at an Incorrect Temperature	NA – Precluded by Tech Specs	
CEA Ejection	NA – safety valves not modeled	
15.5 Increase in Coolant Inventory		
Inadvertent ECCS Operation at Power	Not Analyzed – Precluded by SIS design	
CVCS Malfunction	Yes	Yes
15.6 Decrease in Coolant Inventory		
Inadvertent RCS Depressurization	No	No
Steam Generator Tube Rupture	No	Yes*

* The event, as specified above, use safety valves' upper setpoint limits except Steam Generator Tube Rupture event, which uses MSSV setpoint of 970 psia.

NRC Request 8.d. Non-LOCA Transients:

The St. Lucie Unit 2 reload analysis presented in Reference 3 assumes a 3-second delay time for a loss-of-offsite-power (LOOP) caused by a turbine trip. The LOOP results in loss of power to the reactor coolant pumps (RCPs) which, in turn, reduces the reactor coolant heat removal capability. Justify the 3-second delay time for a LOOP. The justification should include a discussion of the St. Lucie Unit 2 electrical system features and the grid stability analysis to demonstrate that for the licensee's unique grid system configuration, a grid instability condition following a turbine trip will take at least 3 seconds before it results in a loss-of-power to the RCPs. Applicable operational data should be submitted to validate the grid stability evaluation. Since a grid's installed capacity, demand, and spinning reserve vary over time, the licensee should discuss the measures that will be taken to ensure that real-time grid conditions will continue to meet the assumptions inherent in the 3-second LOOP delay.

Response 8.d:

The original grid stability analysis for St. Lucie Unit 2 was performed by W-CE to determine the time to loss-of-offsite-power following turbine trip. This analysis resulted in calculating a time delay of at least 3.3 seconds. The analysis assumptions were recently verified by FPL to be conservative with respect to the current plant configuration. A summary of the review of these assumptions is provided below:

1. The St. Lucie Unit 2 power generation contribution was assumed to be 8% of the total Florida grid minimum load/generation conditions.

   A review performed in 2002 determined that a St. Lucie Unit 2 turbine trip represents a loss of 6.92% to the grid during the minimum load conditions. The 8% assumption thus remains conservative. An evaluation performed in 2004 shows that with Unit 2 off line, with generating capacity replaced by other, more remote, generation sources, the sudden trip of Unit 1 results in a stable response by the offsite system. Voltage is anticipated to drop from 239.9kV to 234.14kV and frequency briefly dips to 59.94Hz and recovers to 59.99Hz.

2. The grid instability study assumed "island" conditions (no support from neighboring grid systems).

   One of the assumptions made in the 1982 study is that the grid system would respond to disturbances as an "island" with relatively few or low-capacity connections to other power grids. The result of "islanding" is an increase in power system disturbances, particularly with respect to frequency oscillations. Since the time of the original study, the intergrid ties have been upgraded from 240kV to 500kV ratings to provide increased capacity. Also, internal grid interconnections and sources of generation in Florida have been upgraded to result in a stiffer grid system. As discussed above, recent studies have shown that loss of one St. Lucie unit, with the other offline, results in relatively insignificant disturbances to the grid. Therefore, the assumption of "islanding" remains conservative.

3. The original study did not take credit for grid system automatic load shedding protection features, which are designed to arrest frequency decline.

   In 1982, Florida utilities were required to have 36% of their load armed with automatic underfrequency relays. Florida's underfrequency load shedding program has been revised since then to have 56% of the load armed with automatic underfrequency relays. The assumption of no underfrequency load shedding remains conservative.

4. The W-CE study did not take credit for "spinning reserve" (operation of generating units at lower than maximum power levels, so that additional generating capacity is immediately available).

   "Spinning reserve" is still used by FPL when appropriate and is also available through the various ties to other utilities. The assumption of no "spinning reserve" is thus conservative.

5. The study assumed an underfrequency (UF) trip setpoint of 58.0 Hz with no time-delay.

   The FPL generating units generally use a UF trip setpoint of 57.0 Hz with a time-delay of 12 seconds (St. Lucie plant included). This assumption thus remains conservative.

6. The study assumed the grid systems to be operated in accordance with standards and to be specifically designed against unstable frequency oscillations resulting from loss of the largest generating unit on that grid.

   Long-term strategic studies and real-time contingency analysis program are used to evaluate the potential loss of single generating unit, transmission lines or transformers, and the loss of two units, lines or transformers for acceptable grid recovery. These programs were a major improvement on the FPL grid system.

<u>Assessment of Electrical Configuration</u>

An assessment of St. Lucie Unit 2 electrical configuration concluded that the immediate loss of one 6.9kV bus and the associated two RCPs due to plant-centered failures following a reactor/turbine/generator trip is possible as a result of a plant-centered component failure. However, there are no apparent common-mode failures that would result in loss of both 6.9kV busses. Therefore, it can be concluded that at least two RCPs, one in each steam generator loop, would be available immediately following a reactor/turbine/generator trip. This failure, however is not currently considered in any St. Lucie Unit 2 30% SGTP design basis analysis.

NRC Request 8.e. Non-LOCA Transients:

The guidance specified in Standard Review Plan (SRP) 15.1.5, 15.2.8 and 15.6.5 indicates that the effects of a loss-of-offsite-power occurring at the worst time should be considered in the analyses of steam line break, feedwater line break and loss-of-coolant accidents, respectively. Discuss the analyses of those three accidents to confirm that the assumed time of loss-of-offsite-power is consistent with the SRP guidance. If the worst time of loss-of-offsite-power is not used in analyses of those accidents, the analyses should be redone with the time of LOOP to be consistent with the SRP guidance.

Response 8.e:

The SRP states:

Assumptions as to the loss of offsite power and the time of loss should be made to study their effects on the consequences of the accident. A loss of offsite power may occur simultaneously with the pipe break or during the accident, or offsite power may not be lost. Analyses should be made to determine the most conservative assumption appropriate to the particular plant design. The analyses should take account of the effect that loss of offsite power has on reactor coolant pump and main feedwater pump trips and on the initiation of auxiliary feedwater flow, and the effects on the sequence of events for these accidents.

The accident analyses consider the possibility of the LOOP occurring "simultaneously with the pipe break" (which would cause an earlier trip from a loss of flow and before the colder water could enter the core to cause a power excursion), "during the accident" (as a consequence of the turbine trip), and "offsite power may not be lost." The modeling of the LOOP "during the accident" includes the effects of delays in losing offsite power arising from the turbine trip. For St. Lucie Unit 2 application, this delay time is assumed to be 3 seconds, which is conservative as discussed in the response to RAI 8.d, above. This practice has been applied in the Westinghouse methodology for over 30 years. Additional information on past precedent for the policies of assuming a non-zero time delay for LOOP "during the accident" and use of time delays are provided in Enclosure 3 Attachment 7 and Enclosure 3 Attachment 10, respectively.

NRC Request 9. Computer Codes Used:

Section 5.1.0.8 of Reference 3 indicates that the Westinghouse computer codes are used for the St. Lucie Unit 2 reload analysis: FACTRAN (WCAP-7908) for fuel rod temperature calculations and TWINKLE (WCAP-7979) for prediction of the kinetic behavior of a reactor. Both codes were previously approved by NRC in use of the licensing application for Westinghouse plants. Justify that the application of those two Westinghouse codes for the St. Lucie Unit 2 (a CE plant) reload analysis is acceptable.

Response 9:

The TWINKLE code is a two-group diffusion theory code, which is capable of performing core neutron kinetics calculations in one, two or three-dimensional geometry. The thermal-hydraulic feedback is provided by an axial fuel rod/hydraulic channel model. For St. Lucie Unit 2, as well as for Westinghouse-designed plants, the code is used only in one-dimensional (axial) geometry for both the CEA withdrawal from subcritical and CEA ejection events. In the one-dimensional axial geometry, the code model is independent of the detailed core geometry. For applicability, the model only has to include the actual axial fuel length and a single fuel rod channel for thermal-hydraulic feedback. To model the specific plant or reload, the kinetic coefficients which affect the transient (delayed neutron fraction, moderator temperature coefficient, doppler power feedback, and trip reactivity) are adjusted to match a conservative prediction of these parameters by the core neutronics design codes. Only bounding values of these parameters are used, as described in WCAP-9272. Therefore, the TWINKLE code is applicable to any plant for which the nuclear design codes are applicable.

Similarly, the FACTRAN code is a radial pellet/clad temperature calculation model, which is used only to conservatively model the hot rod or hot spot heat flux (for CEA withdrawal from subcritical), or post-DNB fuel and clad temperature transient (for CEA ejection). The model uses generic fuel rod properties models, with input values for the plant-specific fuel pellet and clad diameter, core mass flow rate, and initial hot rod or hot-spot heat flux. This can be performed for any plant design. The FACTRAN model uses only conservative values for the gap heat transfer, which is biased to match a conservative set of initial fuel rod temperatures predicted by the fuel rod design model.

Both the TWINKLE and FACTRAN codes have been previously applied and licensed in the analysis of the CEA ejection event for Westinghouse-supplied fuel for the Millstone 2 and Fort Calhoun Unit 1 plants, as well as for a number of non-USA plant designs. Appendix B to the Licensing Report (Reference 3) addresses the code safety evaluation report (SER) requirements for the application of these codes and associated methods to St. Lucie Unit 2.

In follow-up discussions, the NRC also requested that references be identified containing information pertinent to the application of the W-3 correlation for CE plant; specifically for Millstone Unit 2 and Ft. Calhoun Unit 1. The following documents contain information pertinent to the application of the W-3 correlation to Millstone Unit 2:

- Basic Safety Report (BSR), Westinghouse proprietary report for Millstone Unit 2, Docket Number 50-336, submitted via letter, W. G. Counsil (NU) to R. Reid (NRC), March 6, 1980.
- L. S. Rubenstein (NRC), memorandum for T. M. Novak, SER Input on Millstone Unit 2 BSR, February 16, 1982.
- Letter from R. A. Clark (NRC) to W. G. Counsil (NNEC), Safety Evaluation Report of the Westinghouse Basic Safety Report (Millstone Unit 2), January 12, 1982.
- Letter from R. A. Clark (NRC) to W. G. Counsil (NNEC), Final Safety Evaluation of Westinghouse Basic Safety Report for Millstone Unit 2, Docket No. 50-336, February 22, 1982.

In addition, the following readily available documents are known to contain direct information confirming the acceptability of application of the W-3 correlation to Millstone Unit 2:

- Millstone Unit 2. Issuance of Amendment 74 to Facility Operating License DPR-65 Re: Modifying Pressurizer Level Operational Band, ADAMS Accession Number ML012840243, 1982-03-05.
- Millstone Unit 2. Issuance of Amendment 61 to Facility Operating License DPR-65 Re: Sleeved, Reduced Flow and Insert Guide Tubes for the Control Element Assemblies, ADAMS Accession Number ML012840204, 1980-10-06.

No readily available references were identified for the application of the W-3 correlation for Ft. Calhoun Unit, for which the Westinghouse analysis responsibilities are confined to LOCA and limited non-LOCA scope.

NRC Request 10. Classification of Events:

Section 5.1.0.9.3 of Reference 3 indicates that both complete loss of forced reactor coolant flow and full-power single Control Element Assembly (CEA) withdrawal events are classified as Conditions III events that allow a limited amount of fuel damage to occur. The classification and acceptance criteria of those two events are inconsistent with the SRP Chapter 15 guidance (15.3.1 and 15.4.3, respectively) that classifies both events as moderate frequency events with the acceptance criteria that the DNBR does not exceed the specified limit. Justify the inconsistency with the SRP guidance. Also, no results of the analysis for the full-power single CEA withdrawal event are presented in the reload analysis report (Ref. 3). Justify that the St. Lucie Unit 2 reload application without the analysis of the single CEA withdrawal event is acceptable.

Response 10:

The classification, as described in 5.1.0.9, is based on the ANS-N18.1 categorization of the events. As noted in Section 5.1.14.1, the criterion applied to the complete loss of forced reactor coolant flow is consistent with the SRP guidance for a moderate frequency event.

With respect to the single CEA withdrawal event, this event should not have been listed in Section 5.1.0.9.3. The design of the CEA control system precludes the withdrawal of a single CEA due to a single failure and the event is not specifically analyzed in support of the transition to the WCAP-9272 reload methodology and 30% steam generator tube plugging program. This is consistent with the current St. Lucie Unit 2 licensing basis, which does not include an analysis for the single CEA withdrawal event. The event was not specifically analyzed, as noted by its absence from the Licensing Report.

NRC Request 11.a. Initial Conditions:

Table 5.1.0-2 of Reference 3 summarizes the values of initial plant conditions assumed in the St. Lucie Unit 2 reload analysis. For the events analyzed, different values are used for the following key plant parameters: 0, 14.2 and 20 MWt for the RCP heat; 532, 553, 560, 576.5, and 579 °F for the initial vessel average temperature; 2180, 2205, 2225, 2250, and 2400 psia for the initial pressurizer pressure; and 33.1 percent, 63 percent, 65 percent, and 70 percent for the initial pressurizer water level.

a. Provide the rationale for selection of the values of the initial RCP heat, vessel average temperature, pressurizer pressure, and water level for each event analyzed. Justify that the initial values used result in a minimum margin to the pertinent safety limits for each analyzed event, and are applicable to the operating ranges specified in the Core Operating Limits Report (COLR) or TSs: 535°F to 549°F for the cold-leg temperature; 2225 to 2350 psia for the pressurizer pressure (COLR Table 3.2.2); and 27 to 68 percent indicated level for the pressurizer water level (page TS 3/4 4-9). Add to Table 5.1.0-1 the calculated results in terms of the minimum DNBR, peak primary and secondary pressure and the amount of fuel failed to show that the results meets the applicable acceptance criteria for each event.

Response 11.a:

The initial conditions are selected such that the inputs and the uncertainties, if applicable, are applied in the conservative direction.

With respect to the reactor coolant pump heat, the assumed value of the pump heat is not important to the results of most events, as it is a small fraction of the total NSSS power. However, for events analyzed beyond the time of reactor trip, such as the post-trip steamline break event, the pump assumption is of importance. For example, for the post-trip steamline break event, which is a cooldown event and is analyzed beyond the time of reactor trip, the pump heat assumption is zero MWt. In general, nominal heat value of 14.2 MWt is used for most of the events, except for the steam generator tube rupture and the loss of condenser vacuum, where 20.0 MWt is used to conservatively increase the RCS pressurization, and for the CEA misoperation, where 20 MWt is used to increase the RCS temperature for DNB considerations.

With respect to the initial vessel average temperature, the values are selected to ensure that the most limiting condition for the acceptance criterion of interest is achieved. For example, if the intent is to maximize the RCS heatup, such as for primary side overpressurization and for DNB concerns, a "high" initial temperature is selected. For those events that are analyzed applying the revised thermal design procedure (RTDP) methodology, the uncertainties are incorporated into the DNBR limits, and are therefore, not included in the initial conditions. This is consistent with the Westinghouse methodology that has been applied to numerous plants and successfully licensed. 532°F is the nominal inlet and average temperature at hot zero power (HZP), 576.5°F is the nominal hot full power (HFP) average temperature. 579.5°F and 553°F are full power average and inlet temperatures with uncertainties included on the higher side.

With respect to the initial pressurizer pressure, if primary side overpressurization is of concern, the initial pressure is assumed to be the nominal pressure (TS/COLR minimum of 2225 psia) minus uncertainties as this delays a reactor trip on the high pressurizer pressure and results in the highest primary side pressure. A conservative uncertainty of 45 psia is applied. For events that examine the primary side overpressurization but do not trip on the high pressurizer pressure trip, such as the locked rotor event, assuming the TS/COLR maximum pressure plus uncertainties is conservative. As noted above, if DNB is the criterion of interest, the RTDP methodology is applied and uncertainties are statistically convoluted into the DNBR limit and the initial pressurizer pressure of 2225 psia is assumed. Steam generator tube rupture event uses a conservative initial pressure of 2400 psia to maximize the primary-to-secondary leak. For post-trip steamline break events, application of uncertainties on the initial conditions are not applied and have no significant impact on the limiting transient conditions since the pressure conditions at the limiting DNBR point are saturation conditions (from bubble formation) in the upper head of the core. For other events applying the standard thermal design procedure, a nominal pressure of 2250 psia minus an uncertainty of 45 psi is assumed.

With respect to the pressurizer water level, there are varying levels for zero power and full power events. The current full power operating pressurizer level is 63% span and the zero power level is 33.1% span. The maximum allowed TS pressurizer level is 68%. The uncertainty is 2%. The initial value is dependent on the power level and the acceptance criterion being examined (e.g., for events that are analyzed for pressurizer fill, the initial pressurizer level is maximized (68% + 2% uncertainty)). For other events the pressurizer level of 65% of span (63% + 2% uncertainty) is used.

The calculated results for the minimum DNBR, peak primary and secondary pressure, and the amount of fuel failed (if applicable) are provided in the individual analysis sections of the report.

NRC Request 12. Increase in Feedwater Flow:

Item 4 in Section 5.1.1.2 of Reference 3 indicates that the feedwater flow malfunction results in a step increase to 120% of the nominal full-power flow to both steam generators. It is not clear whether a limiting single failure is considered in the analysis of the increased feedwater flow event. As indicated on page 15.1-6a of the Updated Final Safety Analysis Report (UFSAR) complete opening of one feedwater control valve can increase feedwater flow over 20% above nominal. The analysis of record (AOR) for the increased feedwater flow event assumes instantaneous, complete opening of both feedwater control valves. The AOR event represents the worst increased feedwater flow event (the opening of one feedwater control valve) with the worst single failure (the simultaneous opening of the other feedwater control valve). Clarify the worst single failure assumed in the increased feedwater flow event for the St. Lucie Unit 2 reload application.

Response12:

Page 15.1-6a of the UFSAR is misquoted in your question. The text states that,

> *Complete opening of one feedwater control valve can increase feedwater flow by about 5 percent above nominal. ...As a bounding increase in feedwater flow, instantaneous, complete opening of both feedwater control valves has been analyzed. This event assumed a maximum feedwater flow increase of 20% and represents the worst increased feedwater flow event (the opening of one feedwater control valve) with the worst single failure (the simultaneous opening of the other feedwater control valve).*

The 20% increase in flow to both steam generators assumed in Reference 3 is consistent with the assumptions used in the analysis documented on Page 15.1-6a of the UFSAR and bounds the expected flow increase which would credibly occur. This flow increase of 20% thus bounds the worst increased feedwater flow event, the opening of one feedwater control valve, and includes the simultaneous opening of the other feedwater control valve. Additionally, the analysis of this event assumes failure of the high steam generator level signal to close the main feedwater control valves and a failure of the actuation of the feedwater pump trip which results in the assumed delay of approximately 70 seconds to terminate feedwater flow.

NRC Request 13.a. Pre-Trip MSLB Event:

The current licensing basis for St. Lucie Unit 2 includes a Loss of AC Power (LOAC) concurrent with the reactor protection system (RPS) system trip breakers opening (RTBO). The Standard Review Plan dictates that a LOAC be assumed to occur at the worst time during a MSLB event. The analysis presented in the licensing amendment assumed a 3.25 second delay for the LOAC following RTBO. The staff does not agree with this change to the current licensing basis. Assuming a LOAC concurrent with RTBO and repeat the spectrum of break size and MTC cases in order to identify the limiting scenario.

Response 13.a:

As identified in the response to RAI 8.e, above, Westinghouse methodology accounts for the LOAC (LOOP) in accordance with the SRP definitions in considering the possibility of the LOOP occurring "simultaneously with the pipe break," "during the accident" (as a consequence of the turbine trip), and "offsite power may not be lost." The modeling of the LOOP "during the accident" includes the effects of delays in losing offsite power arising from the turbine trip. Additional information on past precedent for the policies of assuming a non-zero time delay for LOOP "during the accident" and use of time delays are provided in Enclosure 3 Attachment 7 and Enclosure 3 Attachment 10, respectively. For the St. Lucie Unit 2 application, this delay time is 3 seconds as discussed in the response to RAI 8.d, above. An additional 0.25-second delay from reactor trip to turbine trip is included in the total delay identified in the analysis. While the current analysis acknowledges the mechanistic link between reactor trip/turbine trip and the presumption of a grid collapse (UFSAR page 15.1-44a), the current analysis has conservatively neglected these delays. The modeling of the LOOP delay times is technically justified based on the response to RAI 8.d.

The justification for the delay in the loss of offsite power actually supports a time delay of at least 3.3 seconds. Assuming 3.0 seconds for the loss of offsite power delay and a 0.25 second delay for the turbine trip is bounded by the 3.3 seconds justification for the loss of offsite power.

NRC Request 13.b. Pre-Trip MSLB Event

Nominal initial conditions are assumed in this analysis. The use of off-nominal values, accounting for instrument uncertainties, has been shown to increase the DNBR degradation. Instrument uncertainties, as they relate to monitoring plant parameters and the operating tents, are accounted for in the setpoints methodology. However, if these same uncertainties impact the DNBR degradation, they must also be accounted for in the transient analyses. Please justify the use of nominal conditions.

Response 13.b:

The use of nominal conditions for DNB related events has been approved by the NRC as described in the revised thermal design procedure report (WCAP-11397-P-A). In the Westinghouse Revised Thermal Design Procedure, the initial condition uncertainties are statistically combined in the calculation of the DNBR design limit. In addition, the instrument uncertainties are accounted for in the safety analysis values for the trip setpoints. This approach actually results in overly conservative accounting of the uncertainties as the initial condition and reactor trip uncertainties tend to overlap one another. For example, the pressurizer pressure transmitter uncertainty is accounted for once in the initial pressurizer pressure uncertainty and again in the high pressurizer pressure reactor trip setpoint. Thus, both the initial condition uncertainties and instrument uncertainties are conservatively accounted for in the safety analyses.

NRC Request 13.c.1. Pre-Trip MSLB Event:

Figure 5.1.5-7 of Reference 3, presents the DNBR degradation for the Pre-Trip MSLB event. The DNBR starts at approximately 2.2 and degrades to 1.442 before being turned around by scram CEAs.

1. Demonstrate that the initial DNBR value (approx. 2.2) is consistent with plant operations at hot full power (HFP) over the range of allowable conditions.

Response 13.c.1:

The DNBR of approximately 2.2 is consistent with the full power DNBR value and assumes that the plant is operating at the design Fr and assumes a reference axial power shape. As the power increases during the pre-trip MSLB event, the axial power shape would tend to become less limiting, however, this effect is not reflected in the DNBR as a function of time presented in Figure 5.1.5-7. With respect to the allowable range of conditions over which the DNBR is valid, the RETRAN simulation of the DNBR accounts for changes in the RCS temperatures (Tavg), pressurizer pressure and power levels, with the assumption of a conservative axial power shape. The DNBR calculated for HFP conditions with the design Fr and conservative axial power shape is 2.258. The actual DNBR would be higher as the actual Fr and axial power shape would not be as limiting as assumed in the safety analyses.

NRC Request 13.c.2. Pre-Trip MSLB Event: See Enclosure 2A

NRC Request 13.d.1. Pre-Trip MSLB Event:

A Variable Overpower - ΔT Power reactor trip function is credited for the Pre-Trip MSLB event.

1. Identify which power indication (either excore neutron flux detectors or core ΔT power) produces the reactor trip.

Response 13.d.1:

The reactor trips which occurred are summarized in the table below:

Reactor Trips for the Pre-Steamline Break Event

Density Coefficient	No Trip	Variable Overpower ΔT	Variable Overpower Excore	Low Steam Pressure
0.00	≤0.5 ft^2	1.0 – 3.2 ft^2	N/A	≥ 3.3 ft^2
0.10	≤0.3 ft^2	0.5 – 3.3 ft^2	N/A	≥ 3.4 ft^2
0.20	≤0.1 ft^2	0.3 – 3.3 ft^2	N/A	≥ 3.4 ft^2
0.30	≤0.1 ft^2	0.3 – 3.4 ft^2	N/A	≥ 3.5 ft^2
0.43	≤0.1 ft^2	0.3 – 0.5 ft^2	1.0 – 3.5 ft^2	≥ 3.6 ft^2

N/A = Not applicable

NRC Request 13.d.2. Pre-Trip MSLB Event:

A Variable Overpower - ΔT Power reactor trip function is credited for the Pre-Trip MSLB event.

2. Demonstrate that rod shadowing and downcomer temperature decalibration effects on excore detector signals were accounted for.

Response 13.d.2:

Rod Shadowing: No control rod motion is assumed to occur during the transient since automatic withdrawal and insertion capabilities are disabled. Therefore, no changes in rod shadowing characteristics will occur during the transient.

Downcomer Temperature Decalibration: The downcomer temperature decalibration effects are explicitly modeled during the transient. The modeling of the downcomer temperature decalibration is based on the density of the water in the RPV downcomer such that, at initial conditions a one-degree F temperature drop, with all other conditions being held constant, would result in a 0.7% reduction in the indicated power level. This modeling is evident from the fact that the nuclear power and the heat flux are both well above the high neutron flux setpoint of 112.2% of nominal power which means that the indicated neutron flux power levels are below the setpoint or else a reactor trip would have occurred.

NRC Rerquest 13.d.3. Pre-Trip MSLB Event

A Variable Overpower - ΔT Power reactor trip function is credited for the Pre-Trip MSLB event.

3. Demonstrate that harsh environment conditions were accounted for in the RPS response and that instruments relied upon are qualified for such conditions.

Response 13.d.3:

The trip setpoint values for the thermal margin/low pressure (TM/LP) trip and low steam generator pressure trip for this event were modeled consistent with a harsh environment. For the thermal margin/low pressure trip, the TM/LP floor setpoint value was revised to incorporate the accident condition uncertainty. Similarly, the low steam generator pressure trip used is based on the nominal setpoint minus the pressure uncertainty corresponding to harsh conditions. Availability of these trip functions is consistent with the previous licensing basis analysis performed for St. Lucie Unit 2. In addition, for cases tripping on the variable high power – excore power signal, the trip signal is only assumed to be operable for 60 seconds after the break initiation, although the cases that tripped on the variable high power - excore power signal all tripped within 15 seconds of event initiation and were non-limiting cases. For the most limiting cases (that is, break sizes analyzed with a moderator density coefficient of 0.30 delta-k/gm/cc), the variable high power - excore power signal reactor trip was not initiated. Rather, protection was provided by the variable high power (thermal power) reactor trip function.

NRC Request 13.e Pre-Trip MSLB Event

Section 5.1.5.2 of Reference 3 states that the core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the RETRAN transient simulation. Demonstrate that the effects of the time-dependent changes in coolant temperature are accounted for in the radial and axial peaking factors.

Response 13.e:

When the pre-trip MSLB event occurs, the core heat flux rises rapidly, while the core inlet temperature changes relatively slowly (the heat flux rises from 100% to approximately 131% during which period the average core inlet temperature drops by about 20°F). The core inlet temperature distribution at 131% power is used in the generation of the core power distribution for use in the DNBR calculation.

The effect of small time-dependent changes in coolant temperature on the core peaking factors during the transient is negligible. The static peaking factor calculation (and power distribution calculation used in the DNBR calculation) uses the most limiting state point from the transient. This is the point at which the heat flux is at its maximum and the temperature in the stuck rod location is at its minimum, resulting in the most limiting peaking factor for the transient. Because the limiting location is highly localized in a single assembly (close to or underneath the stuck CEA), local (radial) variations in temperature with time are only relevant when considered within this limiting assembly; such variations are negligible and so are of no consequence.

NRC Request 14.a.1. Post-Trip MSLB Event: See Enclosure 2A

NRC Request 14.a.2 Post-Trip MSLB Event:

The St. Lucie Unit 2 UFSAR presents four cases, HFP and hot zero power (HZP) with and without LOAC. It has been seen in CE plants that changes in cycle-specific physics data may change which of these four scenarios is most limiting. Further, the amendment fails to convince the staff that LOAC cases will never challenge SAFDLs.

2. Discuss how the results of these four cases will be verified as part of each reload design.

Response 14.a.2:

For the HZP case, the "without LOAC" case is significantly more bounding and the reactivity modeling and shutdown margin assumptions will be verified during each reload design as identified in WCAP-9272-P-A.

NRC Request 14.b. Post-Trip MSLB Event:

The change in computational methods may yield a different sensitivity to single failures. Demonstrate that a failure of one high pressure safety injection (HPSI) train remains the most limiting single failure.

Response14.b:

St. Lucie Unit 2 has redundant feedwater isolation valves in each feedwater line. Therefore, a failure of a feedwater isolation valve will have no effect on the transient and the analysis conservatively bounds the feedwater flow entering the faulted steam generator. Additionally, regardless of the break location, the failure of a main steamline isolation valve will result in no more than a single steam generator blowing down following the receipt of a main steamline isolation signal. The only remaining engineered safety features system failure that has the potential to impact the results of the analysis is the loss of one train of the safety injection system. This failure results in a delay in the delivery of borated water to the core, which turns the event around.

Discussion of the feedwater modeling assumptions for this event prompted an additional NRC question on the pressure-dependence of the assumed flow and sensitivity of this transient to feedwater flow. Additional information on this topic is included in Enclosure 3 Attachment 9.

NRC Request 14.c.1. Post-Trip MSLB Event:

Section 5.1.6.2 of Reference 3, states that the "initial conditions correspond to a subcritical reactor, an initial vessel average temperature at no-load value of 532°F, and no core decay heat."

1. Does the analysis credit any initial amount of subcriticality?

Response14.c.1:

Yes. The reactor is initially at the TS/COLR shutdown margin of 3.6% Δk with the initiation of the transient.

The shutdown margin (SDM) analysis is performed in 3D using ANC. The analysis essentially involves calculating the reactivity swing from the HFP condition to the zero power (ARI - worst stuck rod) tripped condition. The calculation demonstrates that, upon tripping from any power level (over the entire HZP to HFP range), the core will be subcritical by at least the required SDM. Also, the entire operating moderator temperature range is considered (the calculation conservatively assumes that the tripped core cools down to the minimum temperature of 515°F allowed by the Technical Specifications). The calculation also assumes an uncertainty on the moderator temperature and the CEA worth. The calculation accounts for the fact that the CEAs may be inserted as far as the CEA power dependent insertion limits (PDIL) such that not all the CEA worth can be credited. The SDM is calculated conservatively assuming there is zero soluble boron in the coolant (such that the MTC is conservatively negative) and no changes in the xenon concentration. The calculated SDM is reduced (by 50 pcm) to account for a slight reactivity increase due to void collapse (void collapse effects are not explicitly modeled in the ANC calculation).

NRC Request 14.c.2. Post-Trip MSLB Event:

Section 5.1.6.2 of Reference 3, states that the "initial conditions correspond to a subcritical reactor, an initial vessel average temperature at no-load value of 532°F, and no core decay heat."

2. The St. Lucie Unit 2 UFSAR analysis assumes an initial core inlet temperature of 536°F. A higher initial temperature promotes a larger cooldown. Justify the lower value.

Response 14.c.2:

The Westinghouse core design methodology guarantees that the post-trip shutdown margin requirement in the TS/COLR will be satisfied at the no-load temperature of 532°F. Initiating the transient at 536°F, although it would provide higher initial steam pressures and initial steam flows for the break, would simply have to cool down an additional 4°F prior to reaching the guaranteed shutdown margin conditions. This would unnecessarily "waste" some of the available inventory in the steam generators (SG) and result in an earlier dryout of the SGs.

NRC Request 14.d. Post-Trip MSLB Event:

Explain the difference in steam generator (SG) blowdown between the St. Lucie Unit 2 UFSAR analysis and that presented in this license amendment. Although break size is almost identical (6.358 ft2 versus 6.305 ft2), rupture SG dry-out times are substantially different (167 versus approximately 310 seconds).

Response 14.d:

As noted in Reference 3, the feedwater isolation to the faulted loop was implemented 90 seconds following the receipt of a feedwater isolation signal. This results in the substantially different dryout times.

NRC Request 14.e. Post-Trip MSLB Event:

Figure 5.1.6-5 of Reference 3, depicts break mass flow rate for both the faulted and intact SG. The figure shows break flow from the faulted SG terminating at 10 seconds (main steam isolation valve (MSIV) closure). It appears that the labels for faulted and unfaulted SGs are reversed. Is this a correct assessment?

Response 14.e:

The legend for Figure 5.1.6-5 is incorrect. The dashed line should be labeled as "faulted" steam generator transient. The solid line should be labeled as "unfaulted" steam generator transient.

NRC Request 14.f. Post-Trip MSLB Event:

For each case presented, please provide a single plot of reactivity (%Δρ) versus time for each reactivity component (total, scram, Doppler, MTC, safety injection (SI) boron).

Response 14.f:

The RETRAN model does not track the reactivity components in the same manner as is indicated in the request above. For example, the density feedback is modeled as a function of both core coolant density and core boron concentration. Core boron worth is also modeled as a function of both core coolant density and core boron concentration. RETRAN modeling of Doppler is broken down into two components, a "Doppler Temperature" coefficient and a "Doppler Power" coefficient. The "Doppler Temperature" component is effectively a zero power contribution where the fuel temperature is assumed to follow the core coolant water temperature. The "Doppler Power" coefficient is the contribution from the change in fuel temperature above the core coolant temperature as the core power increases.

The RETRAN modeled reactivity characteristics as a function of temperature are provided in Figure 5.1.6-1 of Reference 3. This graph assumes a constant pressure, zero boron concentration, and a zero power core such that the fuel temperature and coolant temperature are identical (Core Average Temperature) and therefore, incorporates both the MTC and "Doppler Temperature" effect.

Figure 5.1.6-2 presents the RETRAN modeled integral of the "Doppler Power" coefficient. As the nuclear power in the core increases, the fuel temperature increases (compared to a zero power condition) driving heat transfer to the coolant. This graph presents the reactivity feedback as a function of the power level in the core.

The scram reactivity is provided in Section 5.1.6.2, Item 4, of Reference 3 and is modeled in RETRAN as a constant value and establishes the 3.6% Δk shutdown margin at the beginning of the transient.

The total reactivity is provided in Figure 5.1.6-11 of Reference 3.

The core boron reactivity is not provided but, for a constant core coolant density, is modeled through a parabolic equation of core boron concentration with the most-negative coefficient at zero ppm and less-negative values as boron concentration increases.

As noted in WCAP-14882-P-A, the RETRAN model for reactivity feedback is based on the LOFTRAN model as described in WCAP-7907-P-A (Section 5).

NRC Request 14.g. Post-Trip MSLB Event:

The St. Lucie Unit 2 UFSAR analysis states, "the β fraction assumed is the maximum value including uncertainties..." The UFSAR states that a maximum value maximizes subcritical multiplication and thus enhances the potential return to power. The analysis presented in the license amendment used a minimum β of 0.0044. Please discuss this inconsistency.

Response 14.g:

For the St. Lucie Unit 2 UFSAR analyses, the sensitivity to a maximum β fraction is based upon sensitivities performed with the reactor initially at full power conditions. Following reactor trip, a larger β results in a larger population of delayed neutrons that are available for fission as $k_{effective}$ is increasing from the fuel and coolant cooldown. As the transient progresses, the point kinetics model, which does not consider the 3-dimensionsional distribution of the delayed neutrons, provides a conservative prediction of the core power.

For multiple reasons (as noted in WCAP-9226-P-A), the Licensing Report (Reference 3) post-trip SLB analyses are initiated at hot zero power conditions. In this case, the delayed neutron level is very low and the core power increase is more dependent upon on the core reactivity, thus a smaller β is used since it results in a faster power increase.

NRC Request 14.h. Post-Trip MSLB Event: See Enclosure 2A

NRC Request 14.i. Post-Trip MSLB Event: See Enclosure 2A

NRC Request 14.j. Post-Trip MSLB Event:

Item 7 in Section 5.1.6.2 of Reference 3 indicates that the SI system is assumed to actuate when the low pressurizer pressure decreases to 1646 psia which is the safety injection actuation signal (SIAS) setpoint in the normal environment. Table 5.1.0-4 of Reference 3 indicates that the hash environment SIAS setpoint is 1578 psia which is applicable to the MSLB inside containment. Explain why the harsh environment setpoint is not used in the MSLB analysis.

Response 14.j.:

The information presented in Table 5.1.0-4 for the safety injection actuation signal (SIAS) on pressurizer pressure-low function needs to be revised since it is not completely accurate. The 1646 psia setpoint value accounts for the harsh environmental allowance, which is conservatively assumed to be 90 psia, and is used in the post-trip steamline break analysis and in the small break LOCA analysis. The 1578 psia setpoint value is overly conservative and is used in the steam generator tube rupture analysis. The value of normal environment analysis setpoint value should be

1691 psia (based on a TS value of 1736 psia minus a conservative normal environment uncertainty of 45 psid).

NRC Request 14.k. Post-Trip MSLB Event:

Item 11 in Section 5.1.6.2 of Reference 3 indicates that no auxiliary feedwater (AFW) is assumed to be delivered during the MSLB event. Discuss the St. Lucie Unit 2 AFW system features and the associate TS requirement to validate the assumption of the AFW model for the MSLB analysis.

Response 14.k:

As noted in Section 7.3.1.1.8 of the St. Lucie Unit 2 UFSAR:

> *However, the initiation of AFW to a steam generator with a low level condition will be prevented by the AFAS logic if the steam generator or its associated auxiliary feedwater supply header is identified as being ruptured.*
>
> *A steam generator is identified as being ruptured when its pressure is approximately 275 psi below the other steam generator coincident with its own low level signal and with the other steam generator and auxiliary feedwater header being identified as not ruptured, per Technical Specification ESFAS trip value requirements.*
>
> *An auxiliary feedwater supply header is identified as ruptured when its pressure is approximately 150 psi below the other feedwater header pressure coincident with its associated steam generator low level signal and with the other steam generator and auxiliary feedwater header being identified as not ruptured, per Technical Specification ESFAS trip value requirements.*

See Technical Specification Table 3.3-3, Item 8, and Table 3.3-4, Item 8.

The auxiliary feedwater assumption is consistent with the current design basis analysis as stated on the UFSAR page 15.1-44c:

> *The minimum CEA shutdown...during the HZP case. In the events analyzed, no auxiliary feedwater enters the affected steam generator as the AFW isolation signal occurs early in the transient and before the initiation of AFW. There is no actuation of AFW for the intact steam generator prior to the time of maximum return to power.*

NRC Request 14.l. Post-Trip MSLB Event:

Figure 5.1.6-4 of Reference 3 shows that the unaffected SG pressure decreases to 620 psia at about 10 seconds and starts to increase to 670 psia from 10 to 20 seconds before it continues to decrease after 20 seconds. The same figure also shows that the faulted SG pressure remains at about 50 psia from 200 to 310 seconds and then decreases to 15 psia from 310 to 340 seconds. Explain the SG pressure changes between 10 to 20 seconds, and 310 to 340 seconds.

Response 14.l:

The intact steam generator pressure recovers between 10-20 seconds due to the steamline isolation.

The decrease in the faulted steam generator pressure is due to the uncovery of the tube bundle and resulting decrease in the heat transfer. See Response 14.m below.

NRC Request 14.m. Post-Trip MSLB Event:

Figure 5.1.6-5 of Reference 3 shows that the MSLB break flow remains at about 500 lbm/sec from 240 to 310 seconds, and then decreases rapidly to 0 lbm/sec from 310 to 340 seconds. No break flow is calculated from 340 to 355 seconds. At about 360 seconds, the break flow increases to 250 lbm/sec and remains at that level until the Figure ends at 400 seconds. Explain the break flow changes during the period from 240 to 400 seconds.

Response 14.m:

The water level in the downcomer provides the driving head for the flow through the bundle region. At about 310 seconds, the water level in the downcomer no longer provides sufficient driving head for the flow and the tube bundle is uncovered. The heat transferred in the bundle region decreases to a very low level and the steaming rate decreases significantly, causing the steam generator pressure to drop. Due to the momentum of the break flow, this pressure upstream of the break drops slightly below atmospheric pressure, which causes the break flow to stop. As the relatively low heat transfer rate in the bundle region continues, the SG pressure eventually increases slightly above atmospheric pressure and the break flow resumes.

NRC Request 14.n. Post-Trip MSLB Event:

Figure 5.1.6-9 of Reference 3 shows that the core heat flux decreases from 5 to 1% between 10 to 20 seconds, and remains at 1% from 20 to 60 seconds before it rapidly increases after 60 seconds. Explain the core heat flux changes from 10 to 60 seconds.

Response 14.n:

At t=0, the fuel rod temperatures are essentially equal to the coolant temperature. For the core, the initial transient is a rapid temperature reduction of the coolant. This initially draws out the stored energy of the fuel and is seen as the initial increase and the peak in the heat flux from the core. As the rate of the cooldown slows down, the core heat flux drops to a lower value and stabilizes (20-60 seconds). At about 60 seconds, after the shutdown margin is depleted, the nuclear power increases rapidly and is followed by an increase in the core heat flux.

NRC Request 14.o. Post-Trip MSLB Event

Figure 5.1.6-11 of Reference 3 shows that the core reactivity increases to the maximum value of 0.6$ at about 65 seconds, and gradually decreases before the core boron concentration (shown in Figure 5.1.6-10) starts to increase at 140 seconds. It also shows that the core reactivity decreases at a rapid rate from 310 to 320 seconds. Explain the core reactivity changes from 65 to 140 seconds and 310 to 320 seconds.

Response 14.o:

The reactivity gradually decreases from about 65 seconds to 140 seconds due to the Doppler feedback caused by the fuel heat up. At about 310 seconds, the cooling provided in the faulted SG decreases, causing the coolant temperatures at the SG exit to increase. This increase in temperature reaches the core and causes a rapid reduction in the reactivity due to the negative moderator feedback coefficient.

NRC Request 15.a Loss of Normal Feedwater Flow and Loss-of-Offsite-Power:

Section 5.1.9 of Reference 3 indicates that in the case of the LOOP event, it is assumed that the reactor is tripped prior to the LOOP. This assumption is inconsistent with the initiating event specified in SPR 15.2.6 for LOAC to the station auxiliaries. Clarify the assumption to be consistent with the SRP guidance.

Response 15.a:

A revised Section 5.1.9, which reflects the LOOP as the initiating event, consistent with SRP 15.2.6, is presented in Enclosure 3 Attachment 2.

NRC Request 15.b. Loss of Normal Feedwater Flow and Loss-of-Offsite-Power:

In the same Section, the licensee claims that the long-term-cooling (LTC) analysis in UFSAR Chapter 10 remains applicable for St. Lucie Unit 2 reload application. Since the licensee uses Westinghouse methods for the reload analysis and changes the plant to a condition with the SG tube plugging increased to 30 percent, the licensee should perform the LTC analysis with Westinghouse methods to show that the auxiliary feedwater system is adequate to remove the decay heat after reactor trip for the new plant condition.

Response 15.b:

For some events, not specifically called out in WCAP-9272 methodology, CESEC method has been retained as the analysis methodology. The UFSAR Chapter 10 LTC analysis addresses the capability of the auxiliary feedwater system to remove the decay heat after the reactor trip. Since the core thermal power and the auxiliary feedwater flow characteristics have not changed, the current analysis conclusions continue to remain applicable for the 30% SGTP conditions. Therefore, the current Chapter 10 long term cooling analysis is retained as the analysis of record.

NRC Request 16.a. Loss of Condenser Vacuum:

Section 5.1.10.2 of Reference 3 indicates that for the Main Steam System (MSS) overpressure case, the power operated relief valves (PORVs) are modeled with one valve(s) aligned to the pressurizer and one valve locked out. Specify the lift setpoint for the PORVs and confirm that the assumption of using PORVs for mitigation of event consequences is consistent with the TS requirements. Add to Table 5.1.10-3 the time when PORVs, pressurizer safety valves (PSVs) and main steam safety valves (MSSVs) are actuated.

Response 16.a:

Per Technical Specification 3/4.4.4, a maximum of one PORV block valve is open with the plant in Mode 1, 2, or 3. Upon reaching a pressurizer pressure setpoint of 2415 psia (2370 psia nominal + 45 psi uncertainty), a high pressurizer pressure reactor trip signal is initiated and a signal is also provided which opens the PORVs.

The PORVs are utilized in the analysis to ensure conservative results are obtained. For example, in the primary overpressure case, both PORVs are locked out to ensure the maximum primary side pressure is obtained. This effectively ignores the logic which opens the PORVs and therefore results in a conservative calculation of the peak RCS pressure. However, for the DNB and Secondary overpressure cases, where primary side pressure relief yields conservative results, the PORV is modeled as active but assumed to open conservatively prior to the reactor trip time based on the high pressurizer pressure reactor trip setpoint.

Table 5.1.10-3 has been updated to reflect the time when the PORVs and MSSVs are actuated. Note that the pressurizer safety valves did not actuate for the secondary overpressurization case as the PORV capacity was sufficient to provide the necessary primary side pressure relief.

Finally, note that the setpoints for the inoperable main steam safety valves, as defined by the St. Lucie Unit 2 Technical Specification LCO 3.7.1.1, were verified to ensure that the applicable acceptance criteria are satisfied.

Table 5.1.10-3
Sequence of Events and Transient Results
Loss of Condenser Vacuum

With Pressurizer Pressure Control (for Main Steam System Overpressure)

Event	Time (seconds)
Turbine trip	10.1
Main Feedwater Terminates (both loops)	10.1
First Main Steam Safety Valve Opens	14.7
Pressurizer Power Operated Relief Valve Opens	18.0
Reactor trip on High Pressurizer Pressure	20.2
Rod motion begins	21.0
Time of peak MSS pressure	21.4
Peak MSS Pressure	1088 psia
MSS Pressure Limit	1100 psia

NRC Request 16.b. Loss of Condenser Vacuum:

Figure 5.1.10-10 of Reference 3 indicates that the calculated DNBR for the loss of condenser vacuum event increases from 2.24 to 2.34 during 10.1 to 18 seconds, and decreases to a minimum value of 2.19 at 22.1 second. Explain the DNBR changes from 10.1 to 25 seconds.

Response 16.b:

Primary pressure increases rapidly between 10 and 18 seconds. The initial DNBR response is driven by this increase in pressure, which increases the DNBR. The core inlet temperature is unaffected by the transient until after 16 seconds at which point it increases to a maximum value at 26 seconds followed by a decrease in temperature. The DNBR response at this point becomes a competing effect between the pressure increase and the temperature increase. The increasing primary side temperature becomes dominant and causes the decrease in DNBR seen between 18 and 22 seconds. The transient is then turned around following the reactor trip and subsequent decrease in primary pressure and temperature.

NRC Request 17.a Asymmetric Steam Generator Transient (ASGT): See Enclosure 2A

NRC Request 17.b. Asymmetric Steam Generator Transient (ASGT):

Item 5 in Section 5.1.11.2 of Reference 3 indicates that the reactivity feedback is weighted to the unaffected loop since end-of-life reactivity feedback is assumed. Discuss the weighted reactivity feedback model and justify the acceptability of its use for an ASGT event analysis.

Response 17.b:

Since the RETRAN model uses point kinetics calculations, conditions for the various core coolant nodes and core conductors must be converted into a single value for each of the feedback characteristics (moderator, Doppler, and boron) being modeled. For particularly asymmetric transients, such as the post-trip steamline break events where the stuck rod condition results in a return-to-power and the core power is highly dependent upon the local conditions, the conditions of the channel with the stuck rod are weighed more heavily in determining the reactivity feedback.

For the ASGT event, a maximum density feedback coefficient (most-negative moderator temperature coefficient) was used. With this, a reduction in temperature would result in positive reactivity feedback and an increase in core power. With this, the coolant channels of the core associated with the unaffected loop (which continues to provide steam flow to the turbine, and thus increased cooling of the primary) were treated as being more important to the determination of core power (80% weighting) than the core channels associated with the affected loop (20% weighting). This is considered to be very conservative for a core without severe misalignment of control rods (e.g., stuck rod, dropped rod).

NRC Request 17.c. Asymmetric Steam Generator Transient (ASGT):

Significant reverse flow and flow oscillation are predicted for the ASGT event: Figures 5.1.11-7 and -19 for steam flow; Figures 5.1.11-8 and -20 for MSSV Loop Bank 1 flow; Figures 5.1.11-9 and -21 for MSSV Loop 2 Bank 1 flow; Figures 5.1.11-11 and -23 for MSSV Loop2 Bank 2 flow; and Figures 5.1.11-12 and -24 for feedwater flow. Explain the flow changes predicted for the ASGT event and justify that the feedwater and steam flow models used to predict the flow are adequate and acceptable.

Response 17.c:

The reverse flow and flow oscillations depicted in the identified figures are not significant to the DNBR results of the transient. As noted in Tables 5.1.11-1 and 5.1.11-2 of the Licensing Report (Reference 3), the minimum DNBR occurs at 17.4 and 17.6 seconds into the transients, respectively.

The oscillatory steam flow for the "affected" loop prior to the secondary safety valves opening reflect an expected behavior of the steam flow between the steam generator and the steam piping. The combination of the rapid stoppage of steam flow from the steam pipe to the steam header and the momentum associated with the steam flow results in a rapid increase in the pressure in the steam piping that overshoots the pressure in the steam generator. The relationship of the relative pressures between the steam generator and the steam piping and the momentum of the steam flow initiate the oscillatory steam flow that dampens out with time. A similar behavior is seen in the "unaffected" loop when turbine trip occurs. The differences for the "unaffected" loop behavior consist primarily of the additional steam header node and the higher initial steam flow at the time of the flow stoppage. The net result is a steam pressure in the steam line that forms a relatively tight oscillation about the steam generator pressure depicted in Figures 5.1.11-6 and -18. It can be seen that the steam generator pressures, during the period of these oscillating flows, have no significant impact on the steam generator pressure transient behavior. Since there is no significant impact on the steam generator pressurization behavior, it will have no significant impact on the DNBR results for the transient.

In support of the Licensing Report analyses, a sensitivity on the potential behavior of the feedwater system was performed. The cases presented in the Licensing Report (Reference 3) reflect a feedwater response where the feedwater flow matches the steam flow of the "unaffected" steam generator. In contrast, a case where the feedwater flow did not respond at all to the change in steam flow resulted in slightly lower peak power levels and insignificant changes in temperature asymmetry at the core inlet. As a result, large variations in the feedwater flow have no significant effect on the DNBR results for the transient.

The behavior of the secondary safety valves reflect the expected behavior of safety valves to "pop" open, release a significant amount of steam that depressurizes the upstream steam system, and then rapidly shut. The net effect of the oscillatory flow of the safety valves can best be seen in Figures 5.1.11-7 and -19. Only the affected loop safety valves open in the time frame of the reactor trip where the steam flow rapidly increases around 17 seconds to a value over 1000 lbm/second. This shows the steam flow from the steam generator to the steam piping from which the secondary safety valves relieve steam. The oscillations seen in these figures are relatively small and inconsequential to the DNBR results of the transient.

NRC Request 18.a. Feedwater Line Break Events:

The complex, dynamic phenomena within the SG during a FWLB event, which would influence SG liquid level, primary-to-secondary heat transfer rates, break flow rate, and discharge enthalpy, are difficult to accurately simulate. The St. Lucie Unit 2 UFSAR analysis uses conservative modeling assumptions to compensate for inaccuracies of the nuclear steam supply system (NSSS) model. A best-estimate approach is attempted in this licensing amendment. Provide empirical data and benchmark cases to validate RETRAN's prediction of the following dynamic parameters for the local conditions experienced during a feedwater line break event of varying break size.

1. SG collapsed and two-phase liquid level,

2. Primary-to-secondary heat transfer rates,

3. SG evaporator enthalpy, quality and void fraction,

4. SG downcomer enthalpy, quality and void fraction,

5. SG feedring enthalpy, quality and void fraction,

6. Discharge enthalpy and quality,

7. Moisture carry-over (entrained liquid), and

8. Break mass flow rate.

Response 18.a:

The design of the St. Lucie Unit 2 steam generators was reviewed in detail and presented no variations from Westinghouse designed steam generators which required a renodalization of the Westinghouse model described in WCAP-14882-P-A. Additional information on SG design comparisons is provided in Enclosure 3 Attachment 5.

In addition, consistent with WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture," and WCAP-9236, "NOTRUMP: A Nodal Transient Steam Generator and General Network Code," both submitted to the NRC in 1978, a NOTRUMP model for the St. Lucie Unit 2 steam generator was developed. Analysis of a feedwater line rupture with the NOTRUMP model demonstrated:

1) The St. Lucie Unit 2 steam generator model behaved similarly to the Westinghouse designed steam generators, and
2) A low steam generator level trip in the faulted steam generator would occur before steam generator tube bundle heat transfer degradation would occur and well before the low steam generator pressure reactor trip (which was used for the reactor trip function in the Reference 3 analysis of the feedwater line rupture)

Therefore, Reference 3 provides a very conservative analysis of the feedwater line break analysis.

WCAP-9236 presents NOTRUMP validation of its modeling by comparison to vessel blowdown tests. Since the submittal of WCAP-9236, the use of NOTRUMP has expanded to simulate licensing basis small break LOCA analyses (WCAP-10079-P-A). Additional information on NOTRUMP is included in Enclosure 3 Attachment 4.

The Westinghouse methodology used for St. Lucie Unit 2 for the prediction of the steam generator transient behavior during a feedline break event is not a new methodology. This methodology was established in 1978 when Westinghouse submitted WCAP-9230 and WCAP-9236. This methodology has been applied to feedline break analyses on Westinghouse designed plants since that time. The NOTRUMP methodology described in these two topical reports was specifically intended to:

1. model the dynamic processes occurring in the various regions of the steam generator during the feedline break event,
2. predict the entrainment characteristics for the break flow, and

3. predict the indicated steam generator level from the differential pressure measurement from the tap locations of the narrow range steam generator level indication system.

The discussion here is focused on bubble rise model assumptions and fluid swell behavior modeling in the RETRAN SG model during the feedline break.

- The bubble rise parameters, as described in WCAP-14882-P-A, are only applied in the uppermost node (i.e., Volume x76 in Figure 3.6-2 of WCAP-14882-P-A) and are designed to create a perfect separation between the vapor and liquid. That is, all liquid is maintained at the bottom of the volume and steam is maintained above the liquid. Since the feedring is located in the node (Volume x77) below the uppermost node and the junction interface is at the bottom of Volume x76, only liquid flow will be modeled into the Volume x77 until dryout of the Volume x76 is approached. This will tend to maximize the liquid content of the Volume x77 and thereby maximize the liquid content of the break flow.

- For the downcomer region below Volume x77 (Volume x78), the volume is treated with homogeneous equilibrium properties. If the pressure and transient conditions are such that upward flow is predicted, the volume-average conditions of the region are used for the flow calculations to Volume x77. If the region is subcooled, the only liquid flow would be passed to Volume 77. If the region is in two-phase conditions, two-phase flow reflecting the average conditions of the region would provide the basis of the flow passed to Volume 77. For this flow calculation:

  - bubble rise parameters are not applied, and
  - *slip correlations are not applied* (i.e., zero slip between the water and liquid phases is used for flow in the junction)

As a result, the RETRAN model is expected to overpredict liquid travel from the Volume x78 to Volume x77 and thereby maximize the liquid content of the break flow. It should also be noted that the RETRAN model has already been approved for feedline break modeling through the SER on WCAP-14882-P-A.

The intent of the St. Lucie Unit 2 30% Steam Generator Tube Plugging and WCAP-9272 Reload Methodology submittal was to apply the Westinghouse methodology to the St. Lucie Unit 2 plant, while explicitly accounting for the specific features of the plant design, setpoints, and Technical Specifications. Westinghouse methodology does not require specific analysis of DNB and RCS overpressurization analyses since, because of the viability of the low steam generator level reactor trip, these criteria would be bounded by analyses of other events. However, because the current UFSAR analyses depict the feedline break as a potential limiting transient with respect to DNBR and RCS overpressurization, a conservative approach was taken for the feedline break event analysis. The St. Lucie Unit 2 UFSAR analysis of feedwater line breaks has several *major conservative assumptions:*

1. Affected steam generator heat transfer rate
   The analyses model instantaneous loss of heat transfer from the steam generator at dryout. Until that point, full heat transfer capability is assumed.
2. Fluid conditions at the break
   A completely liquid discharge is assumed up to the point of steam generator dryout. This is typically described as assuming the feedring location is at the bottom of the downcomer.
3. Affected steam generator level trip
   Credit for the low steam generator level trip is conservatively delayed till the point of steam generator dryout.

These assumptions are grossly conservative.

Westinghouse reviewed the steam generator design and determined that the steam generator modeling described in WCAP-14882-P-A was appropriate and required no renodalization. This was based on the similarities of operational characteristics of the St. Lucie Unit 2 steam generator design compared to Westinghouse steam generator designs. In addition, a more detailed model was developed for the St. Lucie Unit 2 steam generator for the NOTRUMP code consistent with the models developed for WCAP-9230 and WCAP-9236 submittals.

Both the RETRAN and NOTRUMP models specifically include the correct locations and orientations of the steam generator tube bundle, the feedring, and the level taps. It also models the flowpaths available to both liquid and steam in the steam generator.

It is worth noting that the calculations of the NOTRUMP model for the St. Lucie Unit 2 feedline break transient agrees remarkably well with the expected behaviors described in the St. Lucie Unit 2 UFSAR Section 15.2.5.2.4 (pages 15.2-153d through 15.2-153f) as part of the response to the NRC Question 440.81(f) on the original feedwater line break analysis.

- The UFSAR states that a gradual heat transfer reduction is expected, starting when the affected generator liquid inventory decreases to approximately 70,000 lbm. NOTRUMP predicts that the full heat transfer can be maintained to 60,000 lbm of total inventory. Note that the endpoint for the beginning of the tube bundle uncovery transition was not determined since the transient simulation was ended before that point was determined.
- The UFSAR states that a break quality would be expected to transition quickly to two-phase conditions when the liquid inventory drops below 100,000 lbm (UFSAR Figure 15.2.5.2-22). The NOTRUMP model predicts the transition would occur before reaching 90,000 lbm of total inventory.
- The UFSAR states that a steam generator low level trip signal is expected to occur at greater than 70,000 lbm of liquid in the affected steam generator while the NOTRUMP model predicts the low level trip would occur at approximately

70,000 lbm of total inventory, which is noticeably well before the full heat transfer capability begins to be lost.

In summary, the Westinghouse methodology for addressing steam generator dynamics during a feedline break is well established with a long history. A feedline break transient at the St. Lucie Unit 2 plant would not cause a challenge to either DNBR or RCS overpressurization since a low steam generator level trip on the faulted steam generator would be expected to occur well before the tube bundle uncovery would be initiated. The NOTRUMP analysis provides confirmation that the RETRAN analysis, which ignores the low steam generator level trip and allows the transient to progress to tube bundle uncovery conditions, provides an extremely conservative analysis for the RCS overpressurization and DNB criteria.

With respect to any secondary line break DNBR analyses, the steamline break event will always provide a more conservative evaluation for DNBR than the feedline break. The only difference between the steamline break and feedline break is the level of entrainment in the break flow. With no entrainment, the feedline break is similar to a steamline break of the same flow area. As entrainment increases, the cooling capability of the feedline break is reduced and is effectively like a steamline break with a lower flow area. With large levels of entrainment, the time to reach a reactor trip on low steam generator level is reduced and would result in a less limiting set of transient conditions being reached.

NRC Request 18.b.1. Feedwater Line Break Events

The current licensing basis for St. Lucie Unit 2 includes a LOAC concurrent with RTBO for the Condition IV event (e.g. Large FWLB). The Standard Review Plan dictates that a LOAC be assumed to occur at the worst time during a MSLB event. The analysis presented in the licensing amendment assumed a 3.0 second delay for the LOAC following turbine trip. The staff does not agree with this change to the current licensing basis.

1. Assuming a LOAC concurrent with RTBO, repeat the spectrum of break size cases in order to identify the limiting scenario for the Large FWLB event.

Response 18.b.1:

As identified in the response to RAI 8.e, above, Westinghouse methodology accounts for the LOAC(LOOP) in accordance with the SRP definitions in considering the possibility of the LOOP occurring "simultaneously with the pipe break", "during the accident" (as a consequence of the turbine trip), and "offsite power may not be lost". The modeling of the LOOP "during the accident" includes the effects of delays in losing offsite power arising from the turbine trip. Additional information on past precedent for the policies of assuming a non-zero time delay for LOOP "during the accident" and use of time delays are provided in Enclosure 3 Attachment 7 and Enclosure 3 Attachment 10, respectively. For this St. Lucie Unit 2 application, this delay time is 3 seconds as discussed in the response to RAI 8.d, above. An additional 0.25-second delay from reactor trip to turbine trip is included in the total delay identified in the analysis. The modeling of these delay times is technically justified based on the response to RAI 13.a.

For DNBR (as noted in response 18.a), a feedline break with a coincident loss of offsite power would be bounded by the steamline break with a coincident loss of offsite power. This would be a very short term transient for DNBR evaluation which would be terminated by the low flow trip and the heating/cooling effects of the steamline break or feedline break transient on steam generator outlet temperatures would not have sufficient time to reach the core to affect the power or inlet temperature of the core before the control rods reach sufficient insertion in the core to mitigate the transient. In addition, there would be insufficient time for the adverse environment to affect the setpoint modeled for the low flow trip. As a result, the limiting pre-trip steamline break analysis presented in St. Lucie Unit 2 30% Steam Generator Tube Plugging and WCAP-9272 Reload Methodology submittal provides a more limiting set of conditions that would be reached for a steamline break or feedline break with a loss of offsite power at time zero.

NRC Request 18.b.2. Feedwater Line Break Events:

The current licensing basis for St. Lucie Unit 2 includes a LOAC concurrent with RTBO for the Condition IV event (e.g. Large FWLB). The Standard Review Plan dictates that a LOAC be assumed to occur at the worst time during a MSLB event. The analysis presented in the licensing amendment assumed a 3.0 second delay for the LOAC following turbine trip. The staff does not agree with this change to the current licensing basis.

2. For the Condition IV FWLB event, the break spectrum should investigate breaks starting at a minimum break size of 0.20 ft^2.

Response 18.b.2:

In all cases considered (RCS overpressurization, MSS overpressurization, and DNBR), the range of break sizes analyzed was selected such that the limiting case was addressed. In the case of RCS overpressurization, the results showed that 0.28 ft^2 was the most limiting break size. Break sizes below and above 0.28 ft^2 produced less limiting RCS overpressure results. Similarly, in the case of MSS overpressurization, the results showed that 0.050 ft^2 was the most limiting break size. Break sizes below and above 0.050 ft^2 produced less limiting MSS overpressure results. With respect to DNBR, the results showed that 0.25 ft^2 was the most limiting break size. Break sizes below and above 0.25 ft^2 produced less limiting DNBR results.

NRC Request 18.c. Feedwater Line Break Events:

Clearly define the differences in initial conditions, assumptions, and modeling techniques employed in the Chapter 15 and Chapter 10 FWLB events.

Response 18.c:

Since the modeling techniques are completely different in the performance of Chapter 10 analyses versus Chapter 15 safety analyses, there are no direct comparisons that can be made.

NRC Request 18.d. Feedwater Line Break Events:

The MSSV and PSV opening and flow characteristics have a first order effect on calculated peak pressures.

1. Demonstrate that the opening characteristics and lift pressures correspond to manufacturing specifications and test data for these specific valves.

2. Demonstrate that all pressure drops leading up to the valves have been adequately accounted for in the RETRAN model. Include plant piping drawings in response to clarify calculations.

3. Demonstrate that the safety valve flow rates are consistent with test data and were calculated with approved models.

Response 18.d:

PSVs: In general, the opening pressure of the PSVs is based on the set pressure (2500 psia), the tolerance on the set pressure, and the pressure accumulation required to achieve full rated flow. The set pressure (2500 psia) is consistent with the St. Lucie Unit 2 pressurizer safety valves Technical Specification requirements. The safety valve flow is modeled as 212,182 lbm/hr, which is consistent with the actual capacity rating of the St. Lucie Unit 2 pressurizer safety valves. The assumed values for PSV setpoint tolerance is +3% and for accumulation is a maximum of +3%.

The lift pressure assumed in a specific non-LOCA transient analysis depends on the acceptance criterion of interest. For transient analyses in which the reactor coolant system (RCS) overpressurization acceptance criterion is of interest, the lift pressure of the PSVs was maximized by assuming the most positive tolerance and accumulation. In contrast, for transient analyses in which the DNBR acceptance criterion is of interest, the lift pressure of the PSVs is minimized by assuming the most negative tolerance. These values conservatively bound the TS limits.

(MSSVs): The lift pressures for the MSSVs are based on the design set pressures with appropriate tolerances, plus 3% accumulation, plus the pressure drop from the MSSV branch line. The MSSV branch line pressure drop is used to force a slightly smaller effective flow area for the MSSVs since the model defines the safety valve flow based on the steamline pressure (upstream of the MSSV branch line pressure drop). The design pressure and tolerances used are conservative with respect to the TS requirements for the St. Lucie Unit 2 MSSVs and the previous analysis values. The safety valve flows are consistent with the previous St. Lucie Unit 2 analyses, and are conservative with respect to the minimum capacity of the safety valves.

It is necessary to account for the pressure drop from the steam generator to the inlet of the main steam safety valves. With all of the safety valves open, this pressure drop is 36.1 psid, which accounts for a main steamline pressure loss of 21.05 psid, a venturi loss of 5.12 psid and a pressure drop from the main steam safety valve branch lines of 9.96 psid. The 21.05 psid and 5.12 psid were used to define the pressure drop from the steam generator dome to the main steam line since the main steam safety valves are located directly on the main steam lines. The 9.96 psi pressure drop does not need to be accounted for in the defining of the safety valve opening pressures since the effective safety valve flow area has been adjusted by the branch line pressure drop, as noted above. Thus, the calculation of the safety valve flow based on the steamline pressure will be conservative.

NRC Request 18.e. Feedwater Line Break Events:

During a heat-up event, a positive MTC promotes a higher peak pressure. Is the most positive MTC allowed by TSs assumed in this analysis?

Response 18.e:

The most positive MTC allowed by the Technical Specifications, as proposed in this submittal, is modeled in the analyses.

NRC Request 18.f. Feedwater Line Break Events:

Allowing Pressurizer Pressure Control System (PPCS) Sprays function to delay the High Pressurizer Pressure Trip (HPPT) promotes a higher calculated peak secondary pressure. Demonstrate that the peak secondary pressure case presented would not be more severe with the actuation of Pressurizer Sprays?

Response 18.f:

Sensitivity cases performed with the actuation of pressurizer sprays resulted in less limiting overpressure results. Therefore, the case presented in the UFSAR does not model pressurizer sprays.

NRC Request 18.g. Feedwater Line Break Events:

Significant detail was removed from the sequence of events tables relative to the UFSAR. All RPS, ESFAS, AFAS, MSSV/PSV actuations as well as important phenomena need to be included in the sequence of events. Please expand the current tables.

Response 18.g:

See updated tables corresponding to the licensing report tables below.

Table 5.1.12-4
Sequence of Events and Transient Results
Feedwater Line Break
Limiting Break Size = 0.28 ft^2

Without Pressurizer Pressure Control (for Primary RCS Overpressure)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Reactor Trip on Low Steam Pressure	30.8
Rod motion begins	31.5
Pressurizer Safety Valves Open	32.4
Time Of Peak RCS Pressure	33.2
Steamline Isolation	38.4
MSIV Closure	38.4
MSSVs Open	55.7
Peak RCS Pressure	2739 psia
RCS Pressure Limit	2750 psia

Table 5.1.12-5
Sequence of Events and Transient Results
Feedwater Line Break
Limiting Break Size = 0.05 ft^2

Without Pressurizer Pressure Control (for Main Steam System Overpressure)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Pressurizer Relief Valve Opens	24.3
Reactor Trip on High Pressurizer Pressure	37.1
Rod Motion Begins	37.8
First MSSV Opens	39.5
Time of Peak MSS Pressure	41.2
Peak MSS Pressure	1090 psia
MSS Pressure Limit	1100 psia

Table 5.1.12-6
Sequence of Events and Transient Results
Feedwater Line Break
Break Size = 0.25 ft²

With Pressurizer Pressure Control (for Minimum DNB)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Pressurizer Safety Valves Open	32.4
Reactor trip on Low Steam Pressure	40.8
Rod Motion Begins	41.5
Pressurizer Relief Valve Opens	42.5
Steamline Isolation	48.9
MSIV Closure	48.9
First MSSV Opens	55.1
Time of Minimum DNBR	60.9

NRC Request 18.h Feedwater Line Break Events:

Discuss the sequence of events and explain the transient behavior related to the RCS pressure, vessel average temperature, SG mass and pressure, break flow rate and quality (shown in Figures 5.1.12-2 through 22) for the FWLB cases with break sizes of 0.05, 0.25 and 0.28 ft^2.

Response 18.h:

The initial conditions for the RCS pressure, RCS temperature, steam generator mass and steam generator pressure for the different cases presented vary due to case specific assumptions on application of uncertainties on power level, initial temperature, initial SG level, steam generator tube plugging, and RCS flow rate which were made to maximize the severity for the specific criterion.

Break Flow Quality: Break Flow Quality is provided in Figures 5.1.12-7, -14, and -22. For all cases, the trends are similar. The initial break flow quality is zero since the initial discharge consists of subcooled liquid and then transitions to higher quality fluid as the modeled node which contains the feedring begins voiding due to the lack of subcooled feedwater flow, continued addition of saturated liquid recirculation flow from the moisture separators, and reduction in pressure of the node due to the break. This transition reflects the expected uncovery of the feedring. The quality increases toward a value of 1.0 as SG inventory is lost and the node which contains the feedring transitions toward single phase vapor conditions. Limiting conditions are reached for the applicable criterion prior to a quality of 1 being reached.

Break Flow Rate: Break Flow Rate is provided in Figures 5.1.12-6, -13, and -21. The break flow is calculated based on the Moody correlation for saturated conditions and the

Extended Henry correlation for subcooled conditions. The transient behavior for these plots is determined primarily by the SG pressure and junction quality at the break.

SG Mass: Steam generator secondary side total water mass is provided in Figures 5.1.12-4, -11, and -19.

Since feedwater flow to the intact (or "unfaulted") steam generator is assumed to stop at the time of the break, the mass inventory drops as a function of time due to the steam flow from the steam generator. Prior to turbine trip, this steam flow is provided to the turbine. Following turbine trip, steam flow will be provided to the faulted steam generator because of the existing differential in pressure due to the break in the faulted steam generator. In the cases where the break is large enough, steam pressure cannot be maintained following reactor trip and steam line isolation occurs. In this case, the intact steam generator mass remains constant until the steam pressure rises high enough to open the secondary safety valves which causes the mass inventory to decrease again.

The mass inventory for the faulted SG initially drops faster than the intact SG since its losses include both the steam flow to the turbine and the break flow.

- Following turbine trip, the cases with the larger break sizes (RCS overpressurization and DNB cases) experience an increase in inventory as the steam flow from the intact steam generator pressurizes the faulted steam generator. In these cases, reactor trip is initiated by a low SG steam pressure and is quickly followed by the low steam pressure signal which initiates steamline isolation. In these cases, the steamline isolation is implemented during the repressurization following turbine trip. Following the steamline isolation, the inventory decreases due to the break flow.

- For the main steam system (MSS) overpressure case, due to the small break size, there is very little difference in steam pressures in the intact and faulted loops. In addition, the turbine trip, a result of reactor trip, occurs virtually simultaneously with the opening of the first bank of secondary safety valves (approximately 39 seconds in the transient). As a result, the inventory loss of the intact and faulted steam generators continues with only a minor perturbation. Since the reactor is tripped, the combination of the first bank of secondary safety valves and the break flow stabilize the system and remove decay heat. The faulted steam generator inventory stabilizes as the intact steam generator loses inventory as the intact steam generator provides the steam flow for the break via the main steam lines.

SG Pressure: Steam generator pressure is provided in Figures 5.1.12-5, -12, and -20.

- The RCS overpressure and DNB cases provide similar trends during the transient. The combination of the reduction in cooling from the loss of feedwater flow with the loss of mass/energy from the break results in a relatively stable steam pressure until the point where the reduced inventory in the faulted steam generator causes tube bundle uncovery. The corresponding reduction in heat transfer to the secondary side initiates the reduction in the steam pressure. Reactor trip and steamline actuations are initiated from low steam pressure signals. The reactor trip causes turbine trip to occur first and the resulting reduction in steam flow causes the steam pressure to increase. Then, steamline isolation allows the intact steam generator to pressurize and open the steamline safety valves and allows the faulted steam generator to depressurize through mass/energy release through the break.

- Since the limiting break size is so small, the MSS overpressure case looks very similar to a loss of normal feedwater event. There is relatively little mass/energy release through the break and the RCS heats up in response to the loss of feedwater flow. Following reactor trip, turbine trip occurs (at 39 seconds). The ensuing pressure rise causes both the first and second banks of the secondary safety valves to open. The second bank adds more than enough capacity to control the system pressure and prevent overpressurization. The steam pressure then reduces to the point where the first bank of secondary safety valves controls the steam pressure for both steam generators.

Vessel Average Temperature: Vessel average temperature is provided in Figures 5.1.12-3, -10, and -18.

- The RSC overpressure and DNB cases provide similar trends during the transient. As noted above about steam pressures, the combination of the reduction in cooling from the loss of feedwater flow with the loss of mass/energy from the break results in a relatively stable vessel average temperatures until the point where the reduced inventory in the faulted steam generator causes tube bundle uncovery. At approximately 25 seconds, with the corresponding reduction in heat transfer to the secondary side, the steam pressure begins dropping and the vessel average temperature begins increasing. Reactor trip and steamline actuations are initiated from low steam pressure signals. The system temperature increases until adequate cooling is reestablished by the secondary safety valves.

- The MSS overpressure case, as noted above about steam pressures, initially heats up the RCS in response to the loss of feedwater flow. The heatup causes a significant insurge to the pressurizer and results in reactor trip on a high pressurizer pressure condition. Following reactor trip, turbine trip occurs and is immediately followed by opening of the secondary safety valves. With the drop in reactor power, secondary safety valves control the system temperature. The system temperature then reduces to the point where only the first bank of secondary safety valves are needed to control the conditions.

RCS/Pressurizer Pressure: Figure 5.1.12-2 provides the maximum RCS pressure transient for the RCS overpressure case, while Figures 5.1.12-9 and -17 provide the RCS pressurizer pressure transient for the other cases.

- RCS Overpressure Case: The RCS pressure changes little until tube bundle uncovery begins. The resulting RCS temperature increase from tube bundle uncovery, the RCS pressure increase is initiated. The pressure increase continues through reactor and turbine trips. The pressure increase is reversed shortly after the pressurizer safety valves open. The RCS and Pressurizer pressure is then controlled by the primary safety valves until cooldown of the forces a subsequent reduction in pressure.

- MSS Overpressure Case: The pressurizer pressure changes little until the loss of feedwater results in the increase of the cold leg temperatures (approximately 10 seconds). After the reactor trip and turbine trip, the secondary safety valves provide the cooling necessary to control the system temperature increase and, therefore, the RCS pressure. The pressurizer spray valve and PORV operation are not modeled and the pressurizer pressure never reaches the point where pressurizer safety valves are required to open.

- DNB Case: The RCS pressure changes little until tube bundle uncovery begins. Following the RCS temperature increase, resulting from tube bundle uncovery, the RCS pressure increase is initiated. The pressure increase is limited by the spray valve initially but it is insufficient to control the system pressure. The pressure continues to increase until the pressurizer safety valves open (modeled to open at a minimum opening pressure to limit the pressure increase and thereby minimize the calculated DNBR). The initial opening of the secondary safety valves cools the RCS and causes a short-term drop in pressure but a subsequent heatup of the cold legs causes the pressurizer pressure to return back to the control of the pressurizer safety valves.

NRC Request 18.i. Feedwater Line Break Events:

The Semiscale test data for FWLBs (as discussed in Section 4.3.3.1 of NUREG/CR-4945) show that the SG heat transfer capacity remains unchanged until the SG liquid inventory is nearly depleted. This is followed by a rapid reduction to zero-percent with little further reduction in the SG inventory. In light of these test data, the licensee should provide a discussion of the SG heat transfer model used in the FWLB analysis and verify that the model is conservative as compared to the Semiscale test data.

Response 18.i:

As noted in the response to Question 18a, above, NOTRUMP modeling of the feedline break identifies that a reactor trip would occur on a low steam generator level well before tube bundle uncovery occurs. With a conservative delay in the modeling of the reactor trip till tube bundle uncovery occurs (resulting in the steam pressure drop to the low steam pressure reactor trip setpoint), the analysis provides a conservative presentation for the acceptance criterion.

NRC Request 19.a. Decrease in Reactor Coolant Flow Rate:

In Section 5.1.13 of Reference 3, the licensee claims that the partial loss of RCS flow does not need to be analyzed because it is bounded by a complete loss of RCS flow. Since the licensee uses Westinghouse methods and the partial loss of RCS flow may be tripped by a trip signal different from that used in analysis of a complete loss of RCS flow, the licensee should perform analyses of the partial loss of RCS flow for cases with one, two and three RCPs experiencing a pump coastdown, and confirm that the applicable acceptance criteria are met.

Response 19.a:

The current St. Lucie Unit 2 UFSAR in Section 15.3.2.2.5.1 states: "The core and system performance following a partial loss of forced reactor coolant flow would be no more adverse than those following a total loss of forced reactor coolant flow discussed in Subsection 15.3.2.2.6. Therefore, a detailed analysis was not performed."

Independent of this, Westinghouse performed independent analyses for the 1-out-of-4 and 2-out-of-4 RCP trip events at the same time that the complete loss of RCS flow analysis was performed. These analyses confirmed that the complete loss of RCS flow was bounding with respect to the applicable DNBR criterion. The bounding complete loss of RCS flow analysis confirms that the applicable acceptance criteria are met.

The 3-out-of-4 RCP trip event was not analyzed since there is no credible failure that would result in this transient. During normal operation, power is provided to the RCPs through two electrical buses such that each bus supplies two diametrically opposed RCPs. Any failure which would result in loss of power to three pumps also would result in loss of power to the fourth pump.

NRC Request 19.b. Decrease in Reactor Coolant Flow Rate:

Section 5.1.14.2 of Reference 3 indicates that for the total loss of RCS flow analysis, the control rod time from release to full insertion is assumed to be 2.342 seconds. This rod insertion time is non-conservative as compared to 2.66 seconds specified in page 5-7. Clarify the inconsistency of the rod insertion time used in the analysis for various events.

Response 19.b:

The St. Lucie Unit 2 Loss of Flow analysis in support of the 30% Steam Generator Tube Plugging Licensing Report was performed using "reduced" RCS flow at the time of reactor trip, consistent with the total RCS flow conditions present. This technique has been performed in other Westinghouse loss of flow analyses. The data supporting a similar decrease in the rod drop time, based on a decrease in the RCS flow was determined for two Westinghouse PWRs with different rod drop times. The following presents the justification for the application of this approach to the St. Lucie Unit 2 plant.

The rod drop time for any plant is primarily a function of the weight of the control rods, the RCS flow rate, and the resistances within the guide tubes that the rods travel in. As the RCS flow rate is reduced the rod drop time decreases accordingly. To determine a conservative reduction in the rod drop time, several sensitivities were performed for two Westinghouse designed PWRs. The rod drop times for these two PWRs were different, but both were on the same order of magnitude as the St. Lucie Unit 2 rod drop time, that is 2 to 3 seconds. A conservative reduction in the rod drop time can be determined for plants with comparable rod drop times and RCS flow rates, even if the rods may be of varying size and weight. The reason is that changes in the RCS flow change the resistance to the rod drop. The gravitational constant remains unaffected. Therefore, the rod drop time for a rod of a given weight falling into a guide tube with a given resistance will change by a relativistic similar amount to rod of a differing weight and rod drop resistance if the RCS flow rate is varied over the same range of flow rates. The Technical Specification loop flow rate for St. Lucie Unit 2 supports a 3.1 second rod drop time (from electrical power interruption to the CEA drive mechanism until the CEA reaches 90% insertion) based upon a flow rate of 90,750 gpm. The sensitivities for the two Westinghouse plants were run over a range of RCS flow rates from 100,000 gpm down to an RCS flow rate of 60,000 gpm, thereby encompassing the St. Lucie Unit 2 loop flow rate. In addition, the guide tube designs are sufficiently similar between St. Lucie and the Westinghouse fuel assembly such that similar rod drop behavior would be expected.

It should be noted that the reduction in the rod drop time is not linear with the reduction in the RCS flow, as would be expected. However, when the RCS flow rate was varied from 100,000 gpm to lower RCS flow rates, the percent change in the rod drop times for the two plants with the different rod drop times was very similar. Starting from a flow rate on the order of the St. Lucie Unit 2 loop flow rate of around 90,750 gpm, the cumulative percent decrease in the rod drop time for a reduced flow rate of 75,000 gpm was approximately 11.6% and 11.2%, for the two plants. As would be expected to occur, as the RCS flow rate is varied by the same amount for the two different plants, the percent change in the rod drop times was very comparable. Using this information, along with a conservative estimate of the RCS flow rate at the time of control rod release for the loss of flow event (~65,000 gpm), a conservative reduction in the rod drop time was assumed in the safety analyses for the St. Lucie Unit 2 Complete Loss of Flow event. The sensitivity to the reduction in the rod drop time from around 90,750 gpm to 65,000 gpm was calculated to be 16.6%. However, for conservatism, a reduction of only 12% was assumed.

NRC Request 20.a. Boron Dilution Event:

Section 5.1.19.2 of Reference 3 indicates that for the boron dilution analysis, the dilution flow is assumed to be the maximum capacity from one charging pump for the Mode 6 and 5 cases. It is assumed to be the maximum flow from two charging pumps for the Mode 4 case with the plant on shutdown cooling system and the maximum flow from three charging pumps flow for the Mode 4 case with the plant operating with at least one RCP running. For the Modes 3, 2 and 1 cases, the maximum capacity from three charging pumps is assumed for the dilution flow. Discuss the bases for dilution flow used in each case and confirm that the assumptions are consistent with the TS requirements of the number of operable charging pumps, operable shutdown cooling system and RCP for the applicable Modes of operation.

Response 20.a:

The previous uncontrolled boron dilution analysis considered up to three charging pumps operating in all operational modes except Mode 5 drained. The analyses performed in support of the 30% SGTP program, with similar assumptions, resulted in tables defining the applicable critical/initial boron concentrations with one, two, and three charging pumps operating, consistent with the operational conditions in the UFSAR Table 13.7.2-3. The cases provided in the licensing report reflected the general approach of analyzing this event with representative cases as specified in the report. The analysis approach used in generating the boron concentration tables is consistent with the WCAP-9272 reload methodology. The number of operating charging pumps, operable shutdown cooling system (SCS) and RCPs are all modeled consistent with the Technical Specifications.

The dilution flow in each case was calculated using the applicable number of charging pumps, modified using the specific volume at the saturation pressure and applicable temperature to perform the flow density correction.

NRC Request 20.b. Boron Dilution Event:

Provide the values for the maximum critical boron critical concentration, boron worth (pcm/ppm), setpoint for actuation of the boron dilution alarm system, shutdown margin and initial boron concentration used in the analysis, and confirm that the values used will result in a minimum time to reach core criticality and are consistent with the values specified in the applicable COLR or TSs.

Response 20.b:

The following tables provide the key parameters used in the uncontrolled boron dilution analysis. The source range monitor limit (flux multiplication alarm setpoint) used was 2.276, which is based on the equipment setpoint (0.500 volts) and uncertainty (0.2143 volts). The alarm setpoint value and the associated uncertainty are unchanged from their current values. The values used result in acceptable results with respect to the available time to criticality.

2.1.1	Boron Dilution at Power (Mode 1) (No Xenon)	
	a. Maximum critical C_b, HZP, most-reactive burnup, N-1 rods inserted, ppm	1000
	b. Minimum change in C_b from a. above to HFP, rods to insertion limits, ppm	400
2.1.2	Boron Dilution at Startup (Mode 2) (HZP, No Xenon)	
	a. Maximum critical C_b, HZP, most-reactive burnup, N-1 rods inserted, ppm	1000
	b. Minimum change in C_b from a. above to HZP, rods to insertion limits, ppm	400
2.1.3	Boron Dilution at Hot Standby (Mode 3) (No Xenon, 325°F < $T_{avg} \leq T_{HZP}$)	
	a. Maximum critical C_b, most reactive burnup, N-1 rods inserted, ppm	1450
	b. Minimum change in C_b from a. above to N-1 rods inserted, 3.6% $\Delta\rho$ SDM, ppm	325
	c. Variable SDM requirements, SDM vs. C_b	NA
2.1.4	Boron Dilution at Hot Shutdown (Mode 4*) (No Xenon, 200°F < $T_{avg} \leq$ 325°F)	
	a. Maximum critical C_b, most reactive burnup, N-1 rods inserted, ppm	1300*
	b. Minimum change in C_b from a. above to N-1 rods inserted, 3.6% $\Delta\rho$ SDM, ppm	325*
	c. Variable SDM requirements, boron worth as a function of C_b, maximum absolute value, pcm/ppm	NA
2.1.5	Boron Dilution at Cold Shutdown (Mode 5) (No Xenon, $T_{avg} \leq$ 200°F)	
	a. Maximum critical C_b, most reactive burnup, N-1 rods inserted, ppm	Table 2.1.5
	b. Minimum change in C_b from a. above to N-1 rods inserted, 3.0% $\Delta\rho$ SDM, ppm	Table 2.1.5
	c. Variable SDM requirements, boron worth as a function of C_b, maximum absolute value, pcm/ppm	NA
2.1.6	Boron Dilution During Refueling (Mode 6) (No Xenon, $T_{avg} \leq$ 140°F)	
	a. Maximum critical C_b, all rods inserted, ppm	Table 2.1.6
	b. Minimum C_b at k_{eff} < 0.95, ppm	Table 2.1.6

* Except for Mode 4 on Shutdown Cooling System with 3 charging pumps in operation. See Table 2.1.4 for limits for that case.

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

Table 2.1.4 Mode 4 (on SCS) Boron Concentrations with 3 Charging Pumps in Operation			
Minimum Initial CB (ppm)	Maximum Critical CB (ppm)	Minimum Initial CB (ppm)	Maximum Critical CB (ppm)
1200	858	1660	1209
1220	872	1680	1225
1240	886	1700	1241
1260	900	1720	1257
1280	914	1740	1273
1300	928	1760	1290
1320	942	1780	1306
1340	957	1800	1322
1360	973	1820	1338
1380	989	1840	1354
1400	1004	1860	1371
1420	1020	1880	1388
1440	1035	1900	1404
1460	1051	1920	1421
1480	1066	1940	1437
1500	1082	1960	1455
1520	1097	1980	1472
1540	1113	2000	1489
1560	1129	2020	1507
1580	1145	2040	1524
1600	1161	2060	1542
1620	1177	2080	1559
1640	1193	2100	1576

Table 2.1.5 Mode 5 Boron Concentrations			
Minimum Initial CB (ppm)	Maximum Critical CB (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1200	1059	966	851
1220	1077	982	865
1240	1094	997	879
1260	1112	1012	893
1280	1129	1028	907
1300	1146	1043	921
1320	1162	1059	936
1340	1179	1074	952
1360	1196	1089	967
1380	1213	1105	983
1400	1230	1120	998
1420	1248	1136	1014
1440	1265	1151	1029
1460	1282	1166	1045
1480	1299	1182	1060
1500	1317	1197	1076
1520	1334	1213	1091
1540	1351	1228	1107
1560	1368	1243	1123
1580	1386	1259	1139
1600	1403	1274	1155
1620	1420	1290	1171
1640	1437	1305	1187
1660	1453	1321	1203
1680	1470	1337	1219
1700	1486	1352	1235
1720	1502	1368	1251
1740	1519	1384	1267
1760	1535	1400	1283
1780	1552	1415	1299

Table 2.1.5 Mode 5 Boron Concentrations			
Minimum Initial CB (ppm)	Maximum Critical CB (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1800	1566	1431	1316
1820	1583	1447	1332
1840	1600	1462	1349
1860	1617	1479	1365
1880	1634	1496	1382
1900	1651	1512	1398
1920	1668	1529	1415
1940	1684	1546	1432
1960	1701	1563	1450
1980	1718	1580	1467
2000	1735	1597	1484
2020	1752	1614	1502
2040	1769	1631	1519
2060	1786	1647	1536
2080	1803	1664	1554
2100	1820	1681	1571

Table 2.1.6 Mode 6 Boron Concentrations			
Minimum Initial CB (ppm)	Maximum Critical CB (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1720	1378	1186	1096
1730	1385	1194	1104
1740	1393	1203	1113
1750	1401	1211	1121
1760	1409	1220	1129
1770	1417	1228	1138
1780	1425	1237	1146
1790	1433	1245	1154
1800	1441	1254	1162
1810	1449	1262	1171
1820	1457	1271	1179
1830	1465	1279	1187
1840	1473	1288	1196
1850	1480	1296	1204
1860	1488	1305	1212
1870	1496	1313	1220
1880	1504	1322	1229
1890	1512	1330	1237
1900	1520	1339	1245
1910	1529	1347	1254
1920	1537	1356	1262
1930	1546	1364	1270
1940	1554	1373	1279
1950	1562	1381	1287
1960	1571	1390	1295
1970	1579	1398	1303
1980	1588	1407	1312
1990	1596	1415	1320
2000	1605	1424	1328

Table 2.1.6 Mode 6 Boron Concentrations			
Minimum Initial CB (ppm)	Maximum Critical CB (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
2010	1613	1433	1337
2020	1622	1442	1345
2030	1630	1450	1353
2040	1639	1459	1361
2050	1647	1468	1370
2060	1656	1477	1378
2070	1664	1486	1386
2080	1673	1495	1394
2090	1681	1504	1402
2100	1690	1512	1411

NRC Request 21. Rod Ejection Event:

Section 5.1.20-4 of Reference 3 indicates that based on the result of a generic assessment and the UFSAR analysis, the number of rods in departure from nucleate boiling (DNB) conditions is not expected to exceed 9.5%. Since the licensee uses Westinghouse methods to perform the St. Lucie Unit 2 reload analysis for plant conditions with an increase in the SG tube plugging, the generic assessment and the current UFSAR analysis are not applicable to the St. Lucie Unit 2 reload application. The licensee should perform DNBR calculations for the rod ejection event, determine the number of failed rods applicable to the St. Lucie Unit 2 reload conditions, and verify that radiological release acceptance criteria are met.

Response 21:

The reload fuel design and core loading pattern for St. Lucie Unit 2 has been developed using the same nuclear and thermal-hydraulic design codes as for Westinghouse plants. The core loading pattern and operational strategy, using RAOC methodology, is the same as applied to Westinghouse plants, resulting in similar design characteristics in terms of differential rod worths, core DNB and overpower limits, operational peaking factor limits, ejected rod peaking factors, and ejected rod worths. The ejected rod worths used for the CEA Ejection analysis presented in the St. Lucie Unit 2 Licensing Report (Reference 3) are based on conservative, bounding values of $0.50 at beginning of life (BOL), and $0.57 at end of life (EOL). The actual cycle-specific values are lower than those assumed in the analysis.

The generic assessment of the number of fuel rods in DNB, presented in WCAP-7588 Rev. 1-A, is applicable to cores using these same core operational methods and design characteristics. This assessment was performed for a high power density Westinghouse plant assuming an extremely conservative ejected rod worth of $1 of reactivity at BOL hot full power conditions, and determined that "less than 10 percent of the fuel rods enter DNB." Violation of the core insertion limits was required in order to achieve this $1 of ejected rod worth. Since the bounding ejected rod worths used in the St. Lucie Unit 2 analyses are approximately half of the value used in the generic analyses, it follows that the percentage of rods which fail for St. Lucie Unit 2 will be significantly less than the limit (<10%) predicted in the generic analysis. The analysis of the radiological consequences in the L-2003-220 submittal is based on 10% fuel failure.

In response to subsequent clarification requests by the NRC, the following additional information related to the effects of assumptions for ejected rod worth, melting criterion and enthalpy limits is provided.

The number of rods in DNB is addressed in the Westinghouse methodology. The Westinghouse RCCA Ejection Topical Report, WCAP-7588-P-A, which was reviewed and approved by the NRC in January of 1975, described the methodology and results of the rods-in-DNB evaluation in Sections 4.6 and 5.6.2. In Section 5, a worst case was analyzed using a conservatively high ejected rod worth of one dollar, and a conservatively large post-ejection peaking factor of 8.35 at hot full power beginning of life conditions. The worst case is considered to be at hot full power since it has the lowest initial margin to DNB, and at BOL since it has minimal moderator feedback. Although both of these values greatly exceed the expected values for any Westinghouse plant, less than 10% of the fuel rods were found to be below the DNB limit.

An ejected rod time of 0.05 second was used in the St. Lucie rod ejection analyses to be consistent with the previous analysis of record. With respect to the generic studies in WCAP-7588-P-A, the accident models the rod ejection over a 0.1 second time span. The time of 0.1 second to eject a rod is rapid enough such that non-linear feedback effects due to the "s-shape" reactivity curve are minimal. The ejection time of 0.1 second is conservatively short compared to the expected ejection time. This 0.1 second ejection time is part of the rod ejection methodology presented in WCAP-7588-P-A, which is supported by parametric studies which concluded that varying the time of rod ejection from 0.05 second to 0.15 second produced insignificant changes in the clad average and fuel average temperatures. Therefore, there would be insignificant changes in the results based on a 0.05 second versus 0.10 second ejection time.

The basis for the 10% fuel centerline melting criterion is historically to limit the clad strain, which would result in clad failure assuming an uncracked pellet. This clad strain corresponds to approximately 10% fuel melt. The 10 percent fuel melt criterion precludes significant dispersal of molten fuel in the event of a clad failure during an RCCA ejection accident. It also limits the fission product release to the coolant and the resulting off-site radiation exposure. Consequently, the value of less than the innermost 10% of the fuel pellet at the hot spot remains bounded by the dose analyses and is therefore confirmed as part of the rod ejection analysis.

In addition, for the purposes of evaluation of the potential for fuel failure, Westinghouse applies a fuel enthalpy limit of 200 cal/g at the hot spot, which is conservative with respect to the SRP.

NRC Request 22. Chemical and Volume Control System (CVCS) Malfunction:

Item 3 in Section 5.1.21.2 of Reference 3 indicates that initial values of pressurizer pressure, vessel average temperature and pressurizer level are provided in Table 5.1.21-1. This Table on page 5-251 lists the sequence of events for the CVCS malfunction. Specify the correct table that contains the initial values for the pressure, temperature, and water level used in the analysis.

Response 22:

The initial values of pressurizer pressure, vessel average temperature and pressurizer level are provided in Table 5.1.0-2.

NRC Request 23. Inadvertent Opening of the Pressurizer Relief Valves:

Section 5.1.22 of Reference 3 discusses the analysis of pressurizer pressure decrease events caused by an inadvertent opening of both of the pressurizer PORV or an inadvertent opening of a single PSV. The analysis only addresses the fuel performance issue. During the depressurization event, the pressurizer water level may increase to the top of the pressurizer, resulting in a condition outside the operable range of PSVs or PORVs. The licensee should provide information of the calculated pressured water level for the limiting water level increase case to demonstrate that the pressurizer will not fill solid with water and the PSVs and PORVs can be opened or closed on demand during the depressurization event.

Response 23:

The inadvertent opening of the pressurizer relief valves event is analyzed to demonstrate that the DNB design basis is satisfied. With respect to filling the pressurizer, at the time of reactor trip, the pressurizer is not water solid. A specific analysis for filling the pressurizer following reactor trip is not performed as it is not part of the St. Lucie Unit 2 licensing basis. The design basis limiting pressurizer fill event is described in Section 5.1.21 of Reference 3 as CVCS Malfunction event.

NRC Request 24. Primary Line Break Outside Containment:

In Section 5.1.23.5 of Reference 3, the licensee indicates that based on its qualitative assessment, the limiting letdown line break analysis in the UFSAR remains valid. The letdown line break analysis is affected by plant parameters such as pressurizer pressure, RCS temperature and flow, initial RCS water inventory, primary-to-secondary heat transfer, and the reactor trip on low pressurizer pressure signal. All those parameters are affected by decreased RCS flow and increased SG tube plugging as proposed in the St. Lucie Unit 2 reload application. The licensee's qualitative assessment is insufficient for the staff to draw the same conclusion as stated in the quoted Section. The licensee should perform a limiting letdown line break analysis with approved methods for the appropriate plant conditions that reflect the decreased RCS flow and increased SG tube plugging of 30%. The requested information should include a discussion of the methods and assumptions used in the analysis, and the results to demonstrate that the analysis meets the applicable acceptance criteria.

Response 24:

The decrease in minimum allowed RCS flow, and the increase in the maximum SG tube plugging proposed in the St. Lucie Unit 2 reload application, are not being proposed with any change to the range of RCS cold leg temperature, or the pressurizer operating conditions to be covered by the primary line break (PLB) analysis. Therefore, a reanalysis of PLB would be initiated from the same cold leg temperature and pressurizer conditions as the analysis described in UFSAR Section 15.6.3.1.7; and as described below, would result in no change in the break flow prior to reactor trip, and post-trip break flow would remain bounded by the conservative assumptions described in the UFSAR.

Prior to Trip:

With RCS flow reduced to 335,000 gpm, the initial RCS average and hot leg temperatures would be approximately 2.5°F and 5°F higher, respectively, than shown in UFSAR Figure 15.6.3.1-9, but these temperatures do not affect the letdown line leak rate which is only dependent on the upstream (i.e., cold leg) temperature and pressure. RCS temperatures remain constant prior to reactor trip as shown in UFSAR Figure 15.6.3.1-9. The pressure would decrease prior to reactor trip on low pressurizer pressure as shown in UFSAR Figure 15.6.3.1-10, with the pressure determined by the pressurizer conditions and the loss of reactor coolant volume caused by the break. Because the pressurizer conditions, including the range of initial pressure and liquid level, charging flow, and heater capacity are not being changed, Figure 15.6.3.1-10 and the sequence of events in Table 15.6.3.1-8 would remain applicable through the time of trip on low pressurizer pressure trip (for which the setpoint is unchanged). Therefore, pre-trip leakage would be unchanged.

Post-Trip:

For the analysis described in UFSAR Section 15.6.3.1.7, following reactor trip the leak rate was held constant at 45 lbm/sec until 10 minutes after SIAS is initiated on low pressurizer pressure. The leak rate following reactor trip is conservatively held at 45 lbm/sec for 10 minutes. The primary line break event was evaluated for the increase to 30% SGTP; therefore, the leak rate is a historic value from the analysis of record. The leak rate was based on analyses performed with the CESEC computer code which showed that the letdown flow decreased from approximately 49 lbm/sec at reactor trip to less than 41 lbm/sec just prior to closure of the letdown line isolation valves at approximately 82 seconds after reactor trip. However, the dose calculation conservatively assumed the flow is constant at 45 lbm/sec for the entire 10-minute post-trip timeframe. The use of this higher leak rate until 10 minutes after SIAS is also conservative compared to the letdown isolation response time of under 30 seconds following SIAS.

As described in Sections 5.1.23.4 & 5 of Reference 3, any impact of initial RCS flow and tube plugging on post-trip cold leg temperature and pressure would be small, and the previously reported UFSAR results with regard to coolant leakage would remain bounding for the proposed 30% tube plugging conditions.

Dose Consequences:

The alternative source term analyses in L-2003-220 made several conservative assumptions to assure that increased steam generator tube plugging results would be bounded. The unfiltered control room inleakage assumed in the radiological analysis is 33% higher than the proposed licensing basis unfiltered control room inleakage value

(720 cfm versus 540 cfm). The radiological analysis conservatively assumes a constant letdown line break flow that releases over 85,788 lbm in less than 1920 seconds, which bounds the release rate for the increased SGTP case.

NRC Request 25. SGTR with LOOP:

Section 5.1.24 of Reference 3 discusses the analysis of SGTR event with respect to the mass release. The licensee should perform the SGTR event to also address the issue related to the SG overfill. The results of the analysis should demonstrate that, for the limiting conditions, the SG water level condition is consistent with the assumptions used for the radiological release analysis.

Response 25:

The steam generator tube rupture (SGTR) analysis presented in the licensing report utilizes the current methods as described in the UFSAR (CESEC III code) and is not part of the RSAC methodology implementation. Steam generator overfill is not identified as an acceptance criterion for St. Lucie Unit 2 using the methods described in the current licensing basis. In addition to these licensing considerations, the following technical consideration is provided:

> The SGTR transient presented in the licensing report does not approach the overfill condition over the first 1800 seconds of the transient and is near nominal level at 1800 seconds, at which time operator actions can be credited to depressurize the RCS and isolate the affected steam generator per emergency operating procedure.

Since the steam generator level associated with 30% SGTP is not predicted to enter the main steam lines, no additional dose analysis of overfill is required.

NRC Request 26. Emergency Core Cooling System (ECCS) Performance:

The values for the cold-leg temperature are assumed to be 532°F for the large-break LOCA analysis (Table 5.2.3.2-1 of Reference 3) and 552°F for the small-break LOCA analysis (Table 5.2.4.2-1 of Reference 3). Justify that the LOCA analyses are applicable to the operating range of 535°F to 549°F for the cold-leg temperature specified in the proposed COLR Table 3.2.2.

Response 26:

The large break LOCA (LBLOCA) analysis used a minimum value for the initial cold leg temperature. Specifically, it used a value of 532°F, which corresponds to the low end of the operating range specified in the proposed COLR Table 3.2-2 minus a 3°F temperature measurement uncertainty. As listed in Table 3.3-1 of the 1999 EM topical report (Reference 7), the LBLOCA analysis uses a minimum value for the cold leg temperature. Using a minimum value maximizes the peak cladding temperature (PCT) for two general reasons. First, a minimum initial cold leg temperature results in a lower saturation pressure during blowdown and, consequently, lower core flow rates. Secondly, a minimum initial cold leg temperature results in a lower containment pressure during reflood and, consequently, lower core reflood rates.

The small break LOCA (SBLOCA) analysis used a maximum value for the cold leg temperature. Specifically, it used a value of 552°F, which corresponds to the high end of the operating range specified in the proposed COLR Table 3.2-2 plus a 3°F temperature measurement uncertainty. The hot rod cladding temperature during a SBLOCA transient is not significantly impacted by variations in the initial cold leg temperature. Regardless of the initial cold leg temperature, the RCS quickly depressurizes to a pressure that is determined by the steam generator secondary side pressure, which is determined by the opening pressure of the first bank of main steam safety valves. The RCS pressure then remains relatively constant until the break flow changes from saturated/two-phase liquid to steam, which occurs after one or more reactor coolant pump loop seals clear. After loop seal clearing, the RCS pressure again begins to decrease. For the limiting small break LOCA, the PCT occurs several hundred seconds later during the period of partial core uncovery. The amount of the core uncovery, and consequently the PCT, is primarily determined by two competing factors, both of which are independent of the initial cold leg temperature. The two competing factors are the decay heat induced core boil-off rate and the high pressure safety injection pump flow rate. Although it does not have a significant impact on the results of the analysis, a maximum value for cold leg temperature is used in SBLOCA analyses performed with the SBLOCA evaluation models for Combustion Engineering design PWRs (e.g., the S2M evaluation model, which was used in the 30% SGTP analysis) since it results in a maximum amount of initial stored energy in the RCS.

NRC Request 27 RETRAN Model: See Enclosure 2A

NRC Request 28.a. TS 6.9.1.11.b - Core Operating Limits Reports:

As indicated in References 2 and 5, the following topical reports are used for the St. Lucie Unit 2 reload analysis that determines the values of safety parameters, including cycle-dependent parameters that are relocated in the COLR:

1. WCAP-9226 discussing the methods for the steam line break analysis,

2. WCAP-14482-P-A discussing the RETRAN code for the non-LOCA transient analysis, and

3. CE-161, Supplement 1-P-A discussing the FATES-3B code for evaluation of the fuel performance.

Reference 2 does not clearly state whether those reports are included in TS 6.9.1.11.b, or are referenced by a report that is listed in TS 6.9.1.11.b. Generic Letter (GL) 88-16 indicates that the approved topical report should be included in an administrative control document when that report is used to determine cycle-dependent parameters that are located in the COLR. According to GL 88-16, those three reports should be included in TS 6.9.1.11.b. Address consistency with the GL 88-16 guidance for those three reports.

Response 28.a:

WCAP-9226 does not represent analysis methodology and WCAP-9272-P-A is used as the appropriate reference for shutdown margin in the analysis of steam line break. WCAP-9272-P-A is included in the proposed list of TS 6.9.1.11.b as Item 59.

WCAP-14482-P-A is not directly included in TS 6.9.1.11.b list of methodologies. The application of WCAP-14482-P-A for St. Lucie Unit 2 is described in Appendix C of Reference 3. The use of this methodology for St. Lucie Unit 2 is covered by reference, with the inclusion of Item 64 in TS 6.9.1.11.b as specified in Reference 2. Item 64 will be the NRC Safety Evaluation Report on this submittal.

CEN-161(B)-P, Supplement 1-P-A currently exists in TS 6.9.1.11.b as Item 22.

References:

1. L-2003-276, W. Jefferson (FPL) to NRC, St. Lucie Unit 2, Docket No. 50-389, Proposed License Amendment WCAP-9272 Reload Methodology and Implementing 30% Steam Generator Tube Plugging Limit, dated December 2, 2003.

2. Attachments 1 and 3 to Reference 1, Description of the Proposed Changes and Justification, and St. Lucie Unit 2 Marked-up Technical Specification Pages, respectively.

3. Attachment 6 to Reference 1, Westinghouse Licensing Report St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project.

4. Attachment 7 to Reference 1, Proprietary Portions of Westinghouse Licensing Report St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project - Appendix C.

5. Appendix B to Reference 3, Conditional Requirements.

6. L-2003-227, W. Jefferson, Jr. (FPL) to Document Control Desk (NRC), St. Lucie Unit 2, Docket No. 50-389, LBLOCA Evaluation Model 30-Day 10 CFR 50.46 Report, September 10, 2003.

7. CENPD-132, Supplement 4-P-A, Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model, March 2001.

8. W. J. Scherder and C. J. McHugh (editors), Reactor Core Response to Excessive Secondary Steam Release, WCAP-9226-P-A, Revision 1, February 1998

9. Letter from C. E. Rossi (NRC) to J. A. Blaisdell (UGRA Executive Committee), Acceptance for Referencing of Licensing Topical Report, EPRI NP-2511-CCM, Revision 3, 'VIPRE-01: A Thermal-Hydraulic Analysis Code for Reactor Cores,' Volumes 1, 2, 3, and 4, May 1, 1986.

10. Letter from R. A. Clark (NRC) to W. G. Counsil (NNEC), Final Safety Evaluation of Westinghouse Basic Safety Report for Millstone Unit 2, Docket No. 50-336, February 22, 1982.

11. Florida Power and Light Company, NF-TR-95-01 Supplement 1, Nuclear Physics Methodology for Reload Design of Turkey Point and St. Lucie Nuclear Plants, August 1997.

Enclosure 2B

FPL Non Proprietary Version of Enclosure 2A

Responses to NRC RAI

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

NRC Request 8.a. Non-LOCA Transients:

Section 5.1 Reference 3 indicates that the WCAP-9272 methodology is used for the St. Lucie Unit 2 reload analysis. WCAP-9272 identifies for each design basis event the key safety parameters and their limiting directions that result in a minimum margin to the applicable safety limits. Please compare the values of the key safety parameters assumed in the St. Lucie Unit 2 reload analysis with those limiting directions specified in WCAP-9272 for each event analyzed. Identity and justify the differences in the limiting directions of safety parameters assumed in the St. Lucie Unit 2 reload analysis.

Response 8.a:

The following table presents a comparison of the limiting directions for the reactivity feedback parameters identified in WCAP-9272 versus those used in the St. Lucie Unit 2 Licensing Report, which addressed a maximum tube plugging of up to 30%, including the effects of asymmetric steam generator tube plugging.

Comparison of Limiting Direction for Key Safety Parameters Identified in WCAP-9272 and Modeled in the Licensing Report

a, c

[ ]

[1] DNB, core exit quality, linear heat generation rate, and axial power shape limitations.

[2] WCAP-9272 was written when a positive Moderator Temperature Coefficient was not allowed and therefore the conservative assumption for the Doppler Power coefficient was the Maximum feedback assumption. When plants were later analyzed to support a positive Moderator Temperature Coefficient, it was determined that the conservative assumption for the Doppler Power coefficient was the Minimum feedback assumption. With respect to the Moderator Density Coefficient assumption, WCAP-9272 was written when both "Minimum" and "Maximum" reactivity feedback conditions were analyzed. However, it has since been determined that with respect to the acceptance criteria of interest, "Minimum" feedback is the most limiting condition and is the only feedback modeled for this event.

[3] WCAP-9272 was written when a positive Moderator Temperature Coefficient was not allowed and therefore the conservative assumption for the Doppler Power coefficient was the Maximum feedback assumption. When plants were later analyzed to support a positive Moderator Temperature Coefficient, it was determined that the conservative assumption for the Doppler Power coefficient was the Minimum feedback assumption.

[4] Due to differences between Westinghouse-designed and CE-designed steamline break protection logic, intermediate values of moderator density coefficient are limiting for CE-designed plants.

[5] The feedline break event, as described in WCAP-9272, is modeled to demonstrate the adequacy of the auxiliary feedwater system to remove long-term decay heat and stored energy. The Licensing Report (Reference 3) analysis is performed for different criteria, therefore, the limiting direction of the Key Safety Parameters change.

[6] Westinghouse methodology analyzes this event for long term heat removal criterion. This analysis is not performed in the Chapter 15 safety analysis for St. Lucie Unit 2.

[7] The St. Lucie Unit 2 safety injection system does not have sufficient discharge pressure from the safety injection pumps to inject SI flow into the RCS at Mode 1 operating pressure.

[8] See response to NRC Question 10.

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

NRC Request 13.c.2. Pre-Trip MSLB Event:

Figure 5.1.5-7 of Reference 3, presents the DNBR degradation for the pre-trip MSLB event. The DNBR starts at approximately 2.2 and degrades to 1.442 before being turned around by scram CEAs.

2. A minimum DNBR of 1.442 is reported at 12.60 seconds. It is somewhat surprising that the DNBR remains above the Specified Acceptable Fuel Design Limit (SAFDL) at a peak Core Average Heat Flux (CAHF) of 131%. Please provide all of the state parameters at the time of minimum DNBR including local peaking factors, axial power distribution, hot channel flow fraction, core average flow rate, reactor coolant system (RCS) pressure, and core inlet temperature.

Response 13.c.2.:

[ ] a, c

ABB-NV Minimum DNBR = 1.442

NRC Request 14.a.1 Post-Trip MSLB Event:

The St. Lucie Unit 2 UFSAR presents four cases, HFP and hot zero power (HZP) with and without LOAC. It has been seen in CE plants that changes in cycle-specific physics data may change which of these four scenarios is most limiting. Further, the amendment fails to convince the staff that LOAC cases will never challenge SAFDLs.

1. Provide full scope transient simulations for these four cases.

Response 14.a.1:

We acknowledge the importance of power level and operating mode on the transient results for this event. SRP 15.1.5 provides the following guidance:

> *The reactor power level and number of operating loops assumed at the initiation of the transient should correspond to the operating condition which maximizes the consequences of the accident. These assumed initial conditions will vary with the particular NSSS design, and sensitivity studies will be required to determine the most conservative combination of power level and plant operating mode. These sensitivity studies may be presented in a generic report and referenced in the SAR.*

The Westinghouse methodology as described in WCAP-9226-P-A (Reference 8) for the post-trip MSLB initiated from HZP conditions bounds the post-trip event initiated from HFP conditions for a variety of reasons including the absence of decay heat, stored energy and thick metal masses at full power operating temperatures, the assumptions of full main feedwater flow and higher initial steam generator masses. Substantial precedent exists for exclusion of detailed analysis results for events/cases which are justified as being "bounded" (less limiting) by the results of other events/cases presented in the UFSAR. The basis for identification of a "bounded case" is based on knowledge gained regarding the sensitivity of the results to variations in key parameters and/or initial conditions. These sensitivity studies can be based on explicit parametric calculations, but are often cited as a first principle argument, or reference to historical information. Additional information on the basis for exclusion of the HFP cases is provided in Attachment 6.

The basis for exclusion of the HZP cases with LOAC is less obvious. Therefore, Appendix A of the Licensing Report (Reference 3) includes a specific discussion on this case. In addition, the following amplification to the information provided in the aforementioned portion of the FPL submittal is provided.

The current licensing basis analysis was performed with a set of analytical tools whose limitations preclude the ability to account for crossflow effects in the transient calculation, feedback effects between the system model (flow) and the physics model (power), with a single channel model (again, no crossflow) for the calculation of the DNBR. In order to fulfill a perceived requirement to explicitly present analysis results in this case, the analysis allows for an extreme mismatch in the conditions for flow and power that would not be permitted by physics, even under conservative Chapter 15 assumptions. Under these conditions, the transient statepoint determination reflects a power level beyond what would be reached for the low flow conditions associated with the event, purely as an artifact of the modeling limitations. When this high power level is deterministically combined with the realistic low flow conditions, without consideration of crossflow effects (due to using a single channel model), an artificially low DNBR result is calculated. In consequence, the results presented from a case based on these artificial conservatisms bears little resemblance to the physics of this transient.

The request in this RAI is to generate results of a HZP case with LOAC based on the RETRAN, ANC and VIPRE methodology. Development of such a case would be subject to the same types of constraints that applied to the current licensing basis analysis for HZP with LOAC. The results presented from such a case based on these artificial conservatisms would again bear little resemblance to the actual physics of this transient. How this would compare with the licensing basis results would depend significantly on the amount of "fine-tuning" exercised by the analyst(s) in producing a parallel, but "artificial" result for this case. Given that the variability in the results does not arise from differences in tools or standard modeling and methods, but from the choices exercised in the application of artificial conservatisms, one might consider the value of such a comparison questionable in terms of reaching any meaningful conclusion with respect to safety.

At present, Westinghouse does not have a calculational tool or method approved for the analysis of the Steamline Break event with LOAC for a CE plant that would incorporate the modeling capability required to provide transient results consistent with the actual physics of this transient. Nevertheless, such tools and modeling capability do exist, and have been used to supplement the existing historical basis that this case remains non-limiting compared to SLB cases with offsite power available. For example, as a sound engineering practice to supplement the historical information, Westinghouse performed confirmatory calculations using ANCK/VIPRE (each approved separately) to model the HZP SLB with LOAC for St. Lucie Unit 2. [

] [a, c]. Due to licensing status of the tools used for these calculations, they are not approved explicitly (at this time) for performing UFSAR licensing calculations for this transient. However, these results add to the existing industry information that supports the conclusions of the licensing submittal (Reference 3). It is expected that the approval of the RAVE topical will only serve to "formalize" the most recent supporting evidence for omission of SLB HZP with LOAC cases as "non-limiting".

With regard to the comparative results between the Westinghouse calculations described above and the current licensing basis, the current licensing basis approach applies many more conservatisms to the analysis due to the fact that they are not modeling the transient in a physical manner. The Westinghouse analysis applies conservatisms, but also models the transient in a more physical manner. For example, the current licensing basis approach carries out the analysis at 40% flow to avoid the crossflow effect. Westinghouse models the crossflows so it does not have to apply a flow uncertainty to the searched power, but still incorporates appropriate conservatisms.

Based on subsequent post-submittal discussions with the NRC, additional information is provided in Attachment 8.

From the evidence available within the industry and a critical understanding of the conservative, but non-physical, modeling of the current licensing basis analyses, we believe that the conclusion is inexorable that the SLB HZP with LOAC case for St. Lucie Unit 2 (the subject of this response) is non-limiting.

NRC Request 14.h. Post-Trip MSLB Event:

Please identify the Inverse Boron Worth (ppm/%$\Delta\rho$) assumed in the analysis.

Response 14.h:

In the RETRAN model, the boron worth is modeled as:

[ ][a, c]

Where ρ is the core average water density in grams/cc and B_c is the core average boron concentration in ppm.

NRC Request 14.i Post-Trip MSLB Event:

Section 5.1.6.2 of Reference 3 indicates that the RETRAN and ANC codes are used to verify the RETRAN prediction of the average core power/reactivity, and to determine the peaking factors associated with the return-to-power (RTP) in the region of the stuck CEA.

1. Discuss the methods used for determining the average core power and local moderator reactivity feedback during the MSLB RTP core condition. Provide the results of analysis to demonstrate that the power/reactivity responses predicted by RETRAN are consistent with those predicted by ANC. Discuss the asymmetric cooldown effect considered in calculations of the core inlet temperature distribution. The information should include the calculated core inlet temperature distribution at the peak RTP level and a discussion of assumptions used in the calculations justified with adequate testing data.

2. Discuss the methods used to determine the power peaking factors. Provide the values of the calculated total power peaking factors and justify that they are conservative for calculating the minimum DNBR during an MSLB.

Response 14.i:

The limiting statepoint core conditions (power level, inlet temperature etc.) are modeled in 3D in ANC to determine the power distribution data ("power peaking factors" in the question) used in the DNBR calculation. The ANC calculation models the "stuck CEA out" configuration which gives the worst core conditions for DNBR. The analysis includes a check to ensure the core reactivity of the SLB configuration in RETRAN is greater than that predicted by ANC (this assures that the return-to-power level predicted by RETRAN and used in the DNBR calculation is conservatively high). An uncertainty is applied in ANC to the calculated integrated power in the worst channel at SLB conditions.

[

] a, c.

These powers are in very close agreement and as may be seen in the supplemental information in Attachment 3, the small differences between RETRAN and the linked code have a negligible effect on DNBR.

The axial and radial power distribution data for the worst channel is provided to the T&H analyst for DNBR calculation. A 10% uncertainty is added consistent with Westinghouse and CE design. A conservative radial power (flatter) is then used in the DNBR run. Also, a conservative low flow is used with a higher core power. For the HZP post-trip SLB presented in Section 5.1.6.2 of Reference 3, the radial peaking factor is 17.458 and the axial peaking factor is 1.357. DNBR for this event is verified on a cycle-specific basis, using cycle-specific peaking factors. Additional related information is contained in Attachment 3.

There is a strong relationship between core power and local peaking factor (Fq), so that a comparison of Fq (between the WCAP-9272 SLB analysis and the historical current UFSAR analysis) is meaningless without also comparing the core power level used in the two sets of analyses. In terms of the impact on kW/ft, it is the product (Fq * power) which is of relevance. The (Fq * power) obtained in the WCAP-9272 SLB analysis is reasonable compared with typical (Fq * power) values obtained using the current UFSAR methodology.

NRC Request 17.a Asymmetric Steam Generator Transient (ASGT):

Item 3 in Section 5.1.11.2 of Reference 3 indicates that a bounding range of fuel to coolant heat transfer characteristics is evaluated to assure that the limiting statepoints for the ASGT event are generated. Discuss the heat transfer characteristics used to determine the statepoints and verify that the limiting statepoints are obtained.

Response 17.a:

[

]a, c. This is discussed in more detail in Section 3.2 of WCAP-14882-P-A.

a, c

NRC Request 27. RETRAN Model:

Section 3.2 of Reference 4 discusses Lower Plenum Volumes. Discuss the method, including the equations for determining these volumes, and the CE scale tests from which the data was derived. Provide the calculated values of the design mixing characteristics used in the St. Lucie Unit 2 reload analysis, and justify that the CE scale testing data are: (1) applicable to the St. Lucie Unit 2 plant considering its RCS piping arrangement, reactor vessel internal configurations, and fuel geometry features; and (2) acceptable to support the calculated design mixing characteristics.

Response 27:

a, c

a, c

On page 15.1-84g of the St. Lucie Unit 2 UFSAR, the experimental mixing data described above is referenced. Specifically, it is stated that:

The values of the mixing parameters used for the analyses were:*

Fi = [ ]
Fo = [ ]

These parameters are calculated from experimental data obtained from a 0.248 scale model of a CE PWR (Reference 2).

The design of the experiment was based on the laws of similitude ...

The basis for the vessel mixing coefficients that are used in the SLB event analyses have already been applied to the St. Lucie Unit 2 plant, as noted in the response to the NRC Question No. 44080(k) in UFSAR Section 15.1.5.3.5.12.

References

1. L-2003-276, W. Jefferson (FPL) to NRC, St. Lucie Unit 2, Docket No. 50-389, Proposed License Amendment WCAP-9272 Reload Methodology and Implementing 30% Steam Generator Tube Plugging Limit, dated December 2, 2003.

2. Attachments 1 and 3 to Reference 1, Description of the Proposed Changes and Justification, and St Lucie Unit 2 Marked-up Technical Specification Pages, respectively.

3. Attachment 6 to Reference 1, Westinghouse Licensing Report St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project.

4. Attachment 7 to Reference 1, Proprietary Portions of Westinghouse Licensing Report St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transition Project - Appendix C.

5. Appendix B to Reference 3, Conditional Requirements.

6. L-2003-227, W. Jefferson, Jr. (FPL) to Document Control Desk (NRC), St. Lucie Unit 2, Docket No. 50-389, LBLOCA Evaluation Model 30-Day 10 CFR 50.46 Report, September 10, 2003.

7. CENPD-132, Supplement 4-P-A, Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model, March 2001.

8. W. J. Scherder and C. J. McHugh (editors), Reactor Core Response to Excessive Secondary Steam Release, WCAP-9226-P-A, Revision 1, February 1998

9. Letter from C. E. Rossi (NRC) to J. A. Blaisdell (UGRA Executive Committee), Acceptance for Referencing of Licensing Topical Report, EPRI NP-2511-CCM, Revision 3, 'VIPRE-01: A Thermal-Hydraulic Analysis Code for Reactor Cores,' Volumes 1, 2, 3 and 4, May 1, 1986.

10. Letter from R. A. Clark (NRC) to W. G. Counsil (NNEC), Final Safety Evaluation of Westinghouse Basic Safety Report for Millstone Unit 2, Docket No. 50-336, February 22, 1982.

11. Florida Power and Light Company, NF-TR-95-01 Supplement 1, Nuclear Physics Methodology for Reload Design of Turkey Point and St. Lucie Nuclear Plants, August 1997.

Enclosure 3

Supplemental Information

Responses to NRC RAI

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

Enclosure 3

Non Proprietary Attachment

Attachment 1
Comparison of SGTR Input
Between L-2003-220 (AST Submittal) and SGTP Submittal Cases

Enclosure 2A and Attachments 3A and 4A of Enclosure 3
contain 10 CFR 2.390(a)(4) Proprietary Information

Table 2.4-1 (from L-2003-220, Revised to Show Changes in SGTP Case)
Steam Generator Tube Rupture (SGTR) – Inputs and Assumptions

Input/Assumption	Value From L-2003-220	Value Used in Limiting Case for 30% SGTP
Core Power Level	2754 MW_{th} (2700 + 2%)	Same
Initial RCS equilibrium activity (1.0 µCi/gm DE I-131 and 100/E-bar gross activity)	Table 1.7.2-1	Same concentrations per unit mass
Initial secondary side equilibrium iodine Activity (0.1 µCi/gm DE I-131)	Table 1.7.3-1	Same concentrations per unit mass
Maximum pre-accident spike iodine concentration	60µCi/gm DE I-131	Same
Maximum equilibrium iodine concentration	1.0µCi/gm DE I-131	Same
Duration of accident-initiated spike	8 hours	Same
Steam generator tube leakage rate	Faulted SG – 0.15 gpm Intact SG – 0.15 gpm	Same
Time to establish shutdown cooling and terminate steam release	8 hours	Same
Time for RCS to reach 212°F and terminate SG tube leakage	12 hours	Same

Table 2.4-1 (from L-2003-220, Revised to Show Changes in SGTP Case)
Steam Generator Tube Rupture (SGTR) – Inputs and Assumptions

Input/Assumption	Value From L-2003-220	Value Used in Limiting Case for 30% SGTP
RCS Mass	Pre-accident spike – 475,385 lb_m Concurrent spike – 452,000 lb_m	Same. The initial RCS isotopic concentrations (i.e., per unit mass) are established based on the Technical Specification RCS activity concentration limit. The maximum RCS liquid mass is conservatively used to maximize the RCS isotopic inventory for the pre-accident spike. The RCS mass that was the basis for the RCS isotopic concentrations and the letdown system design is utilized for the concurrent iodine spike case to assure consistency between the RCS isotopic concentration basis and appearance rates.
SG Secondary Side Mass	minimum – 105,000 lb_m (one SG)	Same
Integrated Mass Release	Table 2.4-2	See Table 2.4-2 for comparison
Secondary Coolant Iodine Activity prior to accident	0.1 µCi/gm DE I-131	Same
Steam Generator Secondary Side Partition Coefficients	Faulted SG (flashed tube flow) – none Faulted SG (non-flashed tube flow) – 100 Intact SG – 100	Same
Break Flow Flash Fraction	8.76%	Pre-trip (up to 379.2 sec) - 17.19%* Post-trip - 6.6%*
Atmospheric Dispersion Factors Offsite Onsite	 Table 1.8.2-1 Tables 1.8.1-2 and 1.8.1-3	Same
Control Room Ventilation System Time of automatic control room isolation Time of manual control room unisolation	Table 1.6.3-1 360 seconds 1.5 hours	Same

Table 2.4-1 (from L-2003-220, Revised to Show Changes in SGTP Case) Steam Generator Tube Rupture (SGTR) – Inputs and Assumptions		
Input/Assumption	**Value From L-2003-220**	**Value Used in Limiting Case for 30% SGTP**
Breathing Rates Offsite Control Room	 RG 1.183, Section 4.1.3 RG 1.183, Section 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

* The new flashing fractions are based on the thermal-hydraulic data for 30% SGTP.

Table 2.4-2 SGTR Integrated Mass Releases (1)

Time (hours)	Break Flow in Ruptured SG from L-2003-220 (lb_m)	Break Flow in Ruptured SG from 30% SGTP Case (lb_m)	Steam Release from Ruptured SG from L-2003-220 (lb_m)	Steam Release from Ruptured SG from 30% SGTP Case (lb_m)	Steam Release from Unaffected SG from L-2003-220 (lb_m)	Steam Release from Unaffected SG from 30% SGTP Case (lb_m)
0 – 0.5	69,446	77,007(2)	0 - 0.0915 hrs: 546,210 (via Condenser) 0.0915 - 0.5 hrs: 83,942 (via MSSVs)	0 - 0.1053 hrs (379.2 sec): 661,842(2) (via Condenser) 0.1053 – 0.5 hrs: 85,089(3) (via MSSVs)	0 - 0.0915 hrs: 543,030 (via Condenser) 0.0915 - 0.5 hrs: 82,028 (via MSSVs)	0 - 0.1053 hrs (379.2 sec): 656,568(2) (via Condenser) 0.1053 – 0.5 hrs: 83,989(3) (via MSSVs)
0.5 – 2.0	0	Same	0	0	572,026 (via ADVs)	600,628(2) (via ADVs)
2 – 8	N/A	Same	N/A	N/A	907,828	953,219(2)

(1) Flowrate assumed to be constant within time period.
(2) 30% SGTP value from Table 5.1.24-3 in L-2003-276 conservatively increased by 5%.
(3) 30% SGTP value from Table 5.1.24-3 in L-2003-276 conservatively increased by 8%.

Table 2.4-3 60 µCi/gm D.E. I-131 Activities	
Isotope	**Activity (µCi/gm)**
Iodine-131	48.8
Iodine-132	10.15
Iodine-133	60.67
Iodine-134	6.067
Iodine-135	30.33

Isotopic concentrations per unit mass are unchanged from L-2003-220 to the 30% SGTP case since the concentrations are initially based on the Technical Specification limits, which are also per unit mass.

Table 2.4-4 Iodine Equilibrium Appearance Assumptions		
Input Assumption	**Value from L-2003-220**	**Value Used in Limiting Case for 30% SGTP**
Maximum Letdown Flow	128 gpm	Same
Assumed Letdown Flow *	150 gpm at 120°F, 2250 psia	Same
Maximum Identified RCS Leakage	10 gpm	Same
Maximum Unidentified RCS Leakage	1 gpm	Same
RCS Mass	452,000 lb_m	Same. In order to be consistent with the RCS activity based on the Technical Specification RCS concentration limits, the same RCS mass is used for the appearance rate determination.

* maximum letdown flow plus uncertainty

Table 2.4-5 Concurrent Iodine Spike (335 x) Activity Appearance Rate		
Isotope	Activity Appearance Rate (Ci/min)	Total 8 hour production (Ci)
Iodine-131	1.65E+02	7.93E+04
Iodine-132	9.20E+01	4.41E+04
Iodine-133	2.40E+02	1.15E+05
Iodine-134	1.12E+02	5.35E+04
Iodine-135	1.62E+02	7.75E+04

Isotopic concentrations per unit mass are unchanged from L-2003-220 to the 30% SGTP case since the concentrations are initially based on the Technical Specification limits, which are also per unit mass.

Enclosure 3

Non Proprietary Attachment

Attachment 2
Revised Loss of Normal Feedwater Flow and Loss of Offsite Power Write-Up
(Revision to Section 5.1.9 of Attachment 6 of L-2003-276)

Enclosure 2A and Attachments 3A and 4A of Enclosure 3
contain 10 CFR 2.390(a)(4) Proprietary Information

5.1.9 Loss of Normal Feedwater Flow and Loss of Offsite Power

The loss of normal feedwater flow (LONF) event is defined as a complete loss of main feedwater flow while the reactor is operating at the maximum power level. A loss of main feedwater flow may occur due to the following causes:

- Breaks in the main feedwater system piping upstream of the main feedwater check valves
- Failure or trip of the main feedwater pumps, including loss of power (for motor-driven feedwater pumps) or loss of motive steam (for turbine-driven feedwater pump).
- Spurious closure of main feedwater isolation valves or the main feedwater regulating valves.

The immediate consequence of a loss of main feedwater flow is a reduction in the steam generator water level, which if left unmitigated, will ultimately result in a reactor trip and auxiliary feedwater (AFW) actuation on a low steam generator water level signal. Following reactor trip, the rate of heat generation in the RCS (decay heat plus reactor coolant pump heat input) may exceed the heat removal capability of the secondary system. In this case, there will be an increase in the steam generator pressure and an increase in RCS pressure, RCS temperature, and pressurizer water level. This trend continues until the RCS heat generation rate falls below the secondary-side heat removal capability.

At that time, the primary pressure and temperature begin to decrease, thereby terminating the transient in terms of potential challenges to the applicable safety criteria. It is assumed that if such a transient were to occur at the plant, emergency operating procedures would be followed to bring the plant to a stable condition.

A loss-of-offsite-power (LOOP) event is identical to the LONF event except that a loss of power to the RCPs occurs simultaneously with the loss of feedwater flow. Therefore, the post-trip heat removal relies upon natural circulation in the RCS loops.

The consequences of these events are bounded by other analyzed events as follows:

- With respect to core consequences, the LONF and LOOP events are not as limiting as the complete loss of flow event, which is analyzed to demonstrate that the DNB design basis is satisfied.

  The LONF event results in a slight increase in the RCS temperature prior to reactor trip and there is no appreciable increase in the core power and RCS flow is maintained. The DNBR effect of the reduction in RCS flow for the complete loss of flow event is more significant than the effect of the increase in the RCS temperatures observed for the LONF event, prior to reactor trip

In the case of the LOOP event, the RCPs would coast down immediately in addition to the loss of feedwater flow. This transient would essentially be identical to the complete loss of flow event with the only exception that the reduction in feedwater flow will eventually reduce the cooling of the primary system which would result in an increased RCS pressure thereby increasing the DNBR in comparison to the complete loss of flow analysis. The increase in SG primary side exit temperature would not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the LOOP event has similar RCS conditions to the complete loss of flow event with the exception of a higher RCS pressure caused by loss of feedwater flow, as such, the minimum DNBR conditions are bounded by the Complete Loss of Flow event.

In addition, since there is no appreciable power increase in either the LONF or LOOP event and since the fuel centerline melting is primarily driven by the core power, the fuel centerline melt limits will not be challenged. Therefore, the DNB and fuel centerline melting criteria continue to be satisfied for the LONF and LOOP events.

- With respect to overpressurization, the loss of condenser vacuum/turbine trip event (LOCV) will be more limiting than either the LONF or LOOP events. The LOCV presents a much more significant reduction in the heat removal capability of the steam generators than the LONF or LOOP events because the LOCV event combines the loss of normal feedwater with a turbine trip. This causes the LOCV to have a faster pressurization of the RCS compared to the LONF and LOOP events. The net result for the LOCV event is a total loss of secondary heat sink, which results in the greatest challenge to primary and secondary overpressurization. Therefore, the LOCV remains the most limiting event with respect to primary and secondary overpressurization.

- With respect to long-term cooling, the ability of the auxiliary feedwater system to remove decay heat following reactor trip is demonstrated by the analyses presented in Chapter 10 of the Updated Final Safety Analysis Report (UFSAR).

It is the conclusion of this evaluation that for both the LONF and LOOP events, all criteria are bounded by other events. Therefore, no new analysis is required to support the transition to the WCAP-9272 reload methodology or to support the 30% steam generator tube plugging analysis assumption.

Enclosure 3

Non Proprietary Attachment

Attachment 3B

Supplemental Information on Post-Trip Steamline Break with Loss of AC

A flow sensitivity was carried out at the time of maximum return to power. The flow was arbitrarily increased to 4.5, 5, 6, 8, 10, and 40% of flow. The following results were obtained. Note that the 100% flow case is from the full flow statepoint. All the low flow cases are from the low flow RETRAN statepoint but with the flow arbitrarily increased. The RETRAN statepoint flow is 3.54% of nominal flow.

a, c

* The core power is interpolated. VIPRE cannot converge at this low flow and high power level. The DNBRs are from the 4.5% flow case conditions but with the flow reduced back to 3.54%

Note that the 5% flow sensitivity case with the open channel model switched off shows that modeling this event with closed channels is non-conservative. The current licensing basis for this event uses a closed channel model but uses other conservatisms to account for the crossflows indirectly. In particular, the event is very conservatively modeled using 40% flow, which is unrealistic, such that crossflows can be ignored. Then additional conservatisms are applied to take account of the crossflows. Conservatively modeling this event at 40% flow and then applying additional crossflow conservatisms makes the current licensing basis show that the LOAC case is more limiting than the no LOAC case. Further, the approach described here accurately models the predicted flow in the transient and incorporates the crossflow effects.

It can be seen that the case at 2% flow will be less limiting; the table above shows the definite trend in DNBR versus flow. The table also shows that if the RETRAN statepoint is very conservatively analyzed at 40% flow, it could be more limiting than the full flow, consistent with the current licensing basis.

Enclosure 3

Non Proprietary Attachment

Attachment 4B

Supplemental Information on NOTRUMP Modeling for St. Lucie Unit 2

The NOTRUMP computer code is a one-dimensional nodal network code used for the analysis of thermal-hydraulic transients. Although primarily used for small break LOCA analyses, the NOTRUMP computer code has also been used for steam generator simulations, as presented in WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture." This WCAP was submitted to the NRC as the licensing basis for the Westinghouse methodology for analyzing feedwater line break accidents. WCAP-9230 was submitted to the NRC with, and makes reference to, WCAP-9236, "NOTRUMP, A Nodal Transient Steam Generator and General Network Code." These methods have been referenced in all plant submittals with feedwater line break analyses for Westinghouse plants since ~1980.

The nodalization of the steam generator simulation in the NOTRUMP computer code models a detailed representation of the steam generator secondary-side flow path including the primary separators, steam generator downcomer, feedring, and tube bundle. The model also allows for the calculation of the indicated water level, including the effects of downcomer pressure losses, frictional pressure losses, downcomer velocity head, and reference leg calibration. The NOTRUMP computer code also contains several models and features desirable for the purposes of analyzing a steam generator, including drift flux and bubble rise models. These models permit the modeling of vertical slip flow and countercurrent flow, and facilitate the treatment of phase separation (both natural and mechanical) and water level behavior. This allows for a detailed representation of the fluid conditions on the shell-side of the steam generator U-tubes. There is also a swirl vane separator model built into the code.

Nodalization of the plant-specific Westinghouse NOTRUMP steam generator model is presented in Figures 1 to 3, with a description of the fluid node composition provided in Table 1.

a, c

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Enclosure 3

Non Proprietary Attachment

Attachment 5

Geometric/Design Comparison Between St. Lucie Unit 2 Steam Generator Design and Westinghouse Experience Base

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

The St. Lucie Unit 2 steam generators are geometrically and operationally similar to recent Westinghouse designed steam generators. The following tables provide a comparison.

Geometric Comparison

SG Model	Secondary Volume (ft^3)	Tube Height (in)	Lower Shell Diameter (in)	Upper Shell Diameter (in)	Tube OD* (in)	# of Tubes (#)	Heat Transfer Area (ft^2)
St. Lucie Unit 2	7951.56	365.673	156.375	230.125	0.75	8411	90232
Delta-125	8867.96	440.33	165	210	0.688	10025	123538
Delta-94	7515.51	441.8	142	190	0.688	7585	94500
Delta-75	5538.81	418.62	129.38	168.5	0.688	6307	75185
Model F	5850.71	348.19	129.38	168.5	0.688	5626	55000

* Older model steam generators designed by Westinghouse ranged from 0.688" to 0.875".

Operational Comparison:

SG Model	Nominal Level (in)	Nominal Power (MWt)	RCS Flow (gpm)	Full Power T_{avg} (°F)	Full Power Steam Pressure (psia)	Full Power Feedwater Enthalpy (BTU/lb_m)	Full Power Circulation Ratio (fraction)	Full Power Total Mass (lb_m)	% of Total Mass In SG Tube Bundle %
St. Lucie Unit 2	420.625	1360	167500	576.5	859.87	413.84	3.95	142406	37
Delta-125	555.42	1707.5	157500	573.47	839.51	416.36	3.75	185780	35
Delta-94	554	955.25	98000	593	1069.02	419.52	3.92	156301	37
Delta-75	544	970.7	92600	587.4	963.86	419.44	3.3	116060	35
Model F	500	894.75	93600	570.7	828.45	426	3.28	99044	34

Enclosure 3

Non Proprietary Attachment

Attachment 6

Supplemental Information on the Basis for Exclusion of Post-Trip Steamline Breaks From Hot Full Power Initial Conditions

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

The assumptions applied to the post-trip steamline break analysis are designed to maximize the cooldown rate of the reactor coolant system. This supports the conservative nature of the analysis since it maximizes the positive reactivity addition from coolant density increases and also minimizes the time available for the safety injection system to borate the RCS which would offset the positive reactivity addition.

With respect to maximizing the cooldown, it is important to understand the relationship of the CEA insertion limits and the core design verification of the shutdown margin. For each cycle, the core design verifies that the Technical Specification requirement for shutdown margin will be guaranteed by the trip of all the CEAs, except for the most reactive CEA which is assumed to be stuck in a fully withdrawn position, from any power level (assuming the Technical Specification CEA insertion limits are satisfied). The most limiting condition for this verification occurs at end-of-life, full-power conditions. The insertion limits reserve sufficient worth of the CEAs to overcome the reactivity feedback effects of Doppler and moderator, assuming no change in xenon concentration, such that, at fuel and water temperatures at the no-load temperature (532°F) the shutdown margin will be satisfied. This means that reactivity accumulation to achieve a return-to-critical condition is based upon cooldown of the core (fuel and water) below the no-load temperature *and is independent of the initial power level of the core.*

Initiation of transients from full power would not provide bounding conditions for the post-trip analysis because of a variety of effects that will:

- limit the ability of the steam generators to maximize the cooldown, and
- require a greater cooldown to achieve critical conditions.

These effects are:

1. Decay Heat
   Power operation has the direct effect of creating the radioactive isotopes that cause decay heat in the reactor. In the post-trip analysis of the steamline break with a strong negative moderator temperature coefficient, cooldown of the RCS increases the reactivity of the core. After reaching critical conditions, the core attempts to reach an equilibrium temperature where the core power generation offsets the heat removal of the secondary system. If power is being generated by decay heat then the power that needs to be generated by the fission process is reduced. In addition, since the distribution of the decay heat is essentially dependent upon the pre-trip power shape (and power history) conditions, it would not be concentrated in the assumed stuck rod location of the post-trip analysis. As a result, both fission power levels and peaking factors for the post-trip analysis would be lower for a case initiated from an at-power condition when compared to a case initiated from the zero power condition with no decay heat.

2. Xenon Transient
   Reactor trip from power will initiate a short-term, initially rapid, increase in the xenon isotopes, which are created in the core. Due to the strong neutron absorption cross-section of the xenon isotopes that are created, this adds a significant level of negative reactivity to the core, which the post-trip cooldown must also overcome in order to reach criticality and establish a power level to offset the cooldown. The xenon concentration peaks at approximately 11 hours after shutdown and therefore provides a negative reactivity transient throughout the analyzed duration of the post-trip steamline rupture event.

3. Inventory (Mass) in the SGs
   At steady-state, zero-power conditions, each of the St. Lucie Unit 2 steam generators have an additional 80,000 lbm of water inventory compared to steady-state, full-power conditions. This additional liquid inventory at no-load conditions is available to support continued cooldown of the RCS and delay SG tube bundle uncovery/dryout that eventually will terminate the transient.

4. Stored Energy in the RCS
   During power operation, the RCS coolant, structural material, and fuel temperatures are higher than the 532°F used for the definition of the no-load conditions for the required shutdown margin. As a result, a portion of the secondary inventory must be used just to cool the system down to the no-load conditions and thereby limiting the secondary inventory available to support continued cooldown of the RCS below the no-load temperature and delay SG tube bundle uncovery/dryout which eventually will terminate the transient.

Enclosure 3

Non Proprietary Attachment

Attachment 7

Additional Information on the Policy of Using Non-Zero Delay Times for Loss of Offsite Power "During the Transient"

Post-submittal discussions with the NRC provided additional clarification on the NRC questions related to LOOP assumptions for various non-LOCA transients for the St. Lucie Unit 2 30% Steam Generator Tube Plugging application. The question below relates to examples for which the assumption of a non-zero time delay has been assumed for LOOP "during the transient." The basis for the justification of the assumed delay time is provided in the response to RAI Item 8.d.

Question:

With regard to the 3 second delay in loss of power for MSLB and MFLB, can you or Westinghouse provide some examples to support your position, i.e., plants where this has been approved by the NRC as the more conservative case.

Response:

Background

In accordance with the language of the Standard Review Plan and 10 CFR 50, Appendix A, Westinghouse has long adhered to the position that a deterministic zero second delay time is NOT a requirement for loss of offsite power (LOOP) in non-LOCA safety analyses, and that a non-zero delay time may be credited based on proper technical justification of the delay assumed for any specific application. Where it results in a more limiting transient, evidence of the long-standing application of this assumption is confirmed explicitly with the identification of the assumed delay time employed in the UFSAR analysis.

In regard to the specific events identified in discussions with the NRC, examples of NRC approval for this assumption are provided below.

Examples of plants which have assumed a delay from the time of turbine trip until the reactor coolant pumps coast down, due to the loss of offsite power, in the safety analyses include the following.

Millstone 3	2.0 seconds
Seabrook	3.0 seconds
Vogtle 1&2	2.0 seconds
Callaway	2.0 seconds
Farley 1&2	2.0 seconds
South Texas 1&2	2.0 seconds
V.C. Summer	2.0 seconds
Salem 1&2	1.5 seconds

Feedline Break

With respect to the delay in the loss of offsite power for the feedline break event, all of the plants listed above have assumed the delay times above for the time that the reactor coolant pumps coast down following turbine trip in their current NRC-approved licensing basis safety analyses. The results of these analyses are presented in the corresponding plant UFSAR, and are consistent with the long-standing position that a non-zero delay time may be credited where justified.

Steamline Break

The pre-trip steamline break is an example of the case of offsite power available being identified as the limiting case because the time delay for RCP coastdown is sufficiently large to preclude more limiting conditions. This is representative of pre-trip steamline break UFSAR results across the Westinghouse fleet, providing examples for this event as a part of long-standing Westinghouse practice.

Conclusions

Based upon the above information, the NRC has previously approved the use of a non-zero delay time for the loss of offsite power and reactor coolant pump coastdown for the Feedline Break and for the pre-trip Steamline Break events.

Enclosure 3

Non Proprietary Attachment

Attachment 8

Supplemental Information on the Post-Trip Steamline Break with Loss of AC Power Event

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

Introduction

The St. Lucie Unit 2 30% Steam Generator Tube Plugging Licensing Report presented a discussion of the post-trip steamline break with loss of AC power event in Appendix A. It stated that the current UFSAR presents the loss of AC power case as a limiting case based on the CE-developed steamline break analysis. However, the standard Westinghouse methodology justifies that the steamline break case with offsite power available is bounding for licensing basis purposes. The Westinghouse methodology for the steamline break event is documented in the NRC approved Westinghouse topical WCAP-9226-P-A, Reactor Core Response to Excessive Secondary Steam Releases, dated February 1998 (Reference 1).

The analysis methodology and conclusions of WCAP-9226-P-A for the post-trip steamline break event are applicable to the St. Lucie Unit 2. This methodology has been previously applied by Westinghouse to other CE-designed PWR (Reference 2). To further justify this conclusion, St. Lucie Unit 2 specific steamline break without offsite power analyses were performed using NRC approved neutronic and core thermal-hydraulic codes and methods. The conclusions of these analyses demonstrated that the steamline break without offsite power is non-limiting compared to the case with offsite power. Westinghouse and FPL believe that the historical, calculational and applicability rationale and previous licensing precedence established to date provide ample justification for the non-limiting nature of the steamline break with loss of offsite power case. However, the NRC has requested additional clarification on this approach for the St. Lucie Unit 2 application. Specifically, in the July meeting at the NRC offices, attended by FPL and Westinghouse representatives, the NRC requested additional technical information on the conservatisms included in the calculations supporting the aforementioned conclusions, as well as licensing information related to the application of these methods and tools.

To address the NRC's requests, the following supplemental technical information and licensing documentation are summarized in support of the St. Lucie Unit 2 application for 30% SGTP based on the use of the NRC-approved Westinghouse methodology for analyzing the post-trip steamline break event to the CE-designed St. Lucie Unit 2. This supports the conclusions made by Westinghouse that the case with offsite power is limiting with respect to ensuring that the applicable acceptance criteria are conservatively satisfied for both Westinghouse-designed PWRs and for CE-designed PWRs, such as St. Lucie Unit 2.

A. Supplemental Technical Information

A.1. NRC Previous Review of Cross-Flow Modeling in Core for Post-Trip SLB

In NRC RAI 222.11 to the NRC approved topical WCAP-9226-P-A, the NRC stated:

> "Combustion Engineering paper entitled "Design Analysis Using Coupled Neutronic and Thermal Hydraulic Models" by S.G. Wagner et al. was

presented at the Topical Meeting of Advances in Reactor Physics in Gatlinburg, Tennessee (April 1978). This paper presented an evaluation of steam line break analyses using a 3-dimensional coupled thermal-hydraulic neutronic code. ... The paper shows the cross-flow in fuel bundles (open channels) inserts additional reactivity [into the core]...discuss how this effect was considered in WCAP-9226 [the Westinghouse Steamline Break methodology topical]"

In response to this RAI, it was noted that Westinghouse has considered cross-flow effects with an open channel model under low RCS flow conditions, where these effects are most prevalent, for the steamline break event without offsite power event. With the assumption of an open channel model with cross-flow effects considered, the steamline break event without offsite power is non-limiting compared to the steamline break with offsite power available.

A.2. Westinghouse Publications of Code Linkage for Cross-Flow Effects

Westinghouse has published several papers on the code linkage for low flow steamline break analysis. A summary of two papers is provided below.

1. "Inter-Assembly Crossflow Effects in PWR Cores During a Secondary Steamline Rupture," ASME 81-WA/HT-61 (Reference 7) – This paper described three-dimensional core flow and power distribution calculations performed by Westinghouse for a PWR steamline (SLB) break event without offsite power using a coupled (or linked) neutron diffusion code with an open lattice thermal-hydraulic (T/H) code. Code models, core inlet boundary conditions, method of coupling, and analysis results were presented in the paper.

2. "Subchannel Thermal-Hydraulic Analysis at AP600 Low-Flow Steam-Line-Break Conditions," Nuclear Technology Volume 112 December 1995 (Reference 8) - This paper described AP600 low flow SLB analysis using a linked code system THANC, subchannel code THINC-IV linked with a neutronic code ANC. Core T/H models and qualification, solution scheme and qualification of the linked code THANC, and analysis results were presented in the paper. Note that with respect to the layout of the RCS, the AP600 plant is very similar in design to the St. Lucie Unit 2 in that both have a total of two steam generators, each with one hot leg and two cold legs.

A.3. Conservatism in Post-Trip SLB With Offsite Power Analysis

For the St. Lucie Unit 2 SLB analysis, the conservative approach described in WCAP-9226-P-A is being applied. The steamline break is a Condition IV event which must satisfy the dose limit requirements. Westinghouse has conservatively analyzed this event to satisfy Condition II event criteria which precludes fuel damage on a 95/95 basis. Specifically, it has been demonstrated that the DNBR limit is met (no fuel failure). The conservatism used in the standard Westinghouse analysis of the post-trip steamline break event, as reflected in the SER on WCAP-9226-P-A include:

1. A conservative reactor vessel mixing model for core inlet fluid temperature mapping is applied. The supporting data for this mixing model have been previously audited by the NRC staff and its technical consultants.
2. Spatial reactivity coefficients are computed for a conservative scenario which represents the end of operating cycle (EOC) having the most negative moderator temperature coefficient, the most reactive CEA stuck in its fully withdrawn position.
3. Reactivity checks with the three-dimensional neutronic code are also made to verify that the point kinetics model over-predicts the total change in reactivity for conservatism.
4. The worst stuck rod is chosen to be close to the faulted loop to maximize the cooldown of the stuck rod location and therefore maximize the return to power.
5. The Moody critical flow model is used for steam blowdown calculation to maximize the steamline break cooldown.
6. Only pure steam is assumed to exit the break to maximize RCS cooldown.
7. The RCS heat structures (other than the core) are not modeled which results in more rapid primary cooldown.
8. Decay heat is not modeled for a faster RCS cooldown and therefore a greater return to power.

The above conservatisms are also applied to the loss of offsite power case when comparing it with the more limiting case with offsite power available.

B. Licensing Documentation in Support of the St. Lucie Unit 2 Application

B.1. Approval of VIPRE Code for Cross-Flow Modeling

VIPRE is a subchannel analysis code developed from the COBRA code which solves conservation of mass, axial and lateral momentum, and energy equations for the fluid enthalpy, axial flow rate, lateral flow [cross-flow], and momentum pressure drop. The VIPRE capability for cross-flow modeling and benchmarks with Westinghouse design codes THINC and TORC are discussed in detail in the NRC-approved topical reports and SERs (References 3, 4, 5 and 6).

B.2. Approval of VIPRE Code for Non-LOCA Safety Analyses

As noted in the SER on WCAP-14565-P-A (Reference 6), the VIPRE code has been approved for performing PWR non-LOCA safety analyses including the main steamline break event.

B.3. Approval of VIPRE Code for CE-PWR Modeling

The VIPRE code (Reference 3) has been approved by the NRC and is widely used for PWR safety analyses including the CE-designed PWRs. As stated in WCAP-14565-P-A (Reference 4), Westinghouse VIPRE modeling method is applicable to PWRs.

Furthermore, additional VIPRE benchmarks with TORC show that two codes and models are equivalent. The SER on the VIPRE/ABB-NV submittal concludes that VIPRE can replace TORC for CE-PWR applications.

B.4. NRC Approval of Westinghouse Steamline Break Methods for Other PWR Designs

1) Westinghouse has previously applied the WCAP-9226-P-A methodology to the analysis of the post-trip steamline break event for the CE-designed PWR Millstone Unit 2. The NRC approved the Millstone Unit 2 submittal (Reference 2). The analysis approach for the limiting case is consistent with the WCAP-9226-P-A methods for post-trip steamline break events and is also being applied to the St. Lucie Unit 2 30% SGTP submittal.

2) Westinghouse has received NRC approval for the steamline break analyses performed for its AP600 advanced reactor design, including detailed analyses for the steamline break following reactor coolant pump coastdown in natural circulation conditions. The analyses specifically considered cross-flow effects. The NRC SER on the Westinghouse AP600 design is documented in NUREG-1512, Final Safety Analysis Evaluation Report Related to Certification of the AP600 Standard Design Docket No. 52-003, September 1998 (Reference 9). These methods are consistent with those used in the justification for the St. Lucie Unit 2 30% SGTP submittal for the post-trip steamline break with the loss of offsite power event.

B.5. NRC Approval of SLB Results From Linked Codes

In order to properly consider reactivity insertion due to flow redistribution, the moderator density used in the neutronic code is obtained from the T/H subchannel code with the open channel model based on power distributions from the neutronic code. The two codes can be linked to allow automated data transfer and iterations until convergence criteria in the neutronic code are met for both core average power level and power distribution. Such a code linkage does not change computational methods of either the neutronic or the T/H codes.

The linked neutronic and T/H codes show a more severe core response compared to the neutronic code with only the closed channel model for the SLB with loss of offsite power event. The results of the linked codes also confirm that even with the reactivity insertion from cross-flow, the SLB case with loss of offsite power is bounded by the case with offsite power available.

Over the years, Westinghouse has linked NRC-approved neutronic codes and T/H subchannel codes using the method described above for the loss of offsite power SLB analysis.

1. In response to the RAI 222.11 in WCAP-9226-P-A, the neutronic design code was linked with the THINC-IV (THINC) code (Reference 7). The results and

conclusions have been reviewed and approved by the NRC staff (References 1 and 2).

2. For the AP600 SLB analysis, the THINC code was again linked with the NRC-approved ANC code (Reference 8). The results and conclusions have been reviewed and approved by the NRC staff (Reference 9).

3. For the St. Lucie Unit 2 SLB analysis, the NRC-approved SPNOVA code was linked with the VIPRE code. There is no change to the linking methodology as was used previously in References 7 and 8 for the WCAP-9226 and AP600 applications. Although it is a kinetic code, SPNOVA was run in the static mode linked with VIPRE, similar to the previous THURTLE/THINC and ANC/THINC linkages. The data transfer mechanism has been verified and validated in support of the NRC-approved topical report WCAP-15806-P-A (Reference 10).

B.6. NRC Approval of VIPRE for SLB Case with Loss of Offsite Power

As indicated before, the NRC staff has approved the VIPRE code and Westinghouse modeling method for PWR applications. Specifically, VIPRE is capable of modeling the SLB case with loss of offsite power as demonstrated in the following NRC-approved topical reports:

1) Applicability of the VIPRE code to the low flow conditions with a steep power gradient with rod bundle test results (Reference 3);
2) Equivalency with Westinghouse design code THINC (Reference 4);
3) Equivalency with Westinghouse design code TORC (Reference 5).

Conclusion

The NRC has requested clarification on the approach of applying the standard NRC approved Westinghouse method for the post-trip steamline break event to the CE designed St. Lucie Unit 2. This clarification focuses on the limiting case of the post-trip steamline break event. The current St. Lucie Unit 2 UFSAR specifically analyzes the post-trip steamline break with loss of offsite power case using very conservative assumptions, as noted in Appendix A to the St. Lucie Unit 2 30% SGTP Licensing Report (Attachment 6 to L-2003-276). The NRC-approved WCAP-9226-P-A concludes that the steamline break event with offsite power is the bounding case. The supplemental information provided herein summarizes the licensing precedence and analytical results justifying the approach used by Westinghouse in analyzing the post-trip steamline break event. Based on the WCAP-9226-P-A methodology, the SLB case with offsite power remains the bounding case for St. Lucie Unit 2, just as it is the limiting case for Westinghouse designed PWR.

References:

1. W. J. Scherder and C. J. McHugh (Editors), "Reactor Core Response to Excessive Secondary Steam Release," WCAP-9226 Revision 1, February 1998.

2. Letter from R. A. Clark (NRC) to W. G. Counsil (NNEC), "Safety Evaluation Report of the Westinghouse Basic Safety Report (Millstone Unit 2)," January 12, 1982.

3. C. W. Stewart, et al., "VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores," Volumes 1 – 3 (Revision 3, August 1989), Volume 4 (April 1987), NP-2511-CCM-A, Electric Power Research Institute.

4. Y. Sung, et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A, October 1999.

5. Y. Sung, et al., "Addendum 1 to WCAP-14565-P-A, Qualification of ABB Critical Heat Flux Correlations With VIPRE-01 Code," May 2003.

6. Letter from H. N. Berkow (NRC) to J. Gresham (Westinghouse), "Final Safety Evaluation for WCAP-14565-P-A, Addendum 1, and WCAP-15306-NP-A, Addendum 1, 'Qualification of ABB Critical Heat Flux Correlation with VIPRE-01 Code' (TAC No. MB9509)," April 2004.

7. J. Woodcock, "Inter-Assembly Crossflow Effects in PWR Cores During a Secondary Steamline Rupture," ASME 81-WA/HT-61, American Society of Mechanical Engineers Winter Annual Meeting, November 15-20, 1981.

8. T. Morita, et al., "Subchannel Thermal-Hydraulic Analysis at AP600 Low-Flow Steam-Line-Break Conditions," Nuclear Technology, Volume 112, pp. 401-411.

9. NUREG-1512 "Final Safety Analysis Evaluation Report Related to Certification of the AP600 Standard Design Docket No. 52-003," September 1998.

10. C. L. Beard, et al., "Westinghouse Control Rod Ejection Accident Analysis Methodology Using Multi-Dimensional Kinetics," WCAP-15806-P-A, October 2003.

Enclosure 3

Non Proprietary Attachment

Attachment 9

Additional Information on Feedwater Flow Sensitivity and Boron Initiation Timing for Post-Trip MSLB

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

The post-trip steamline break analyses documented in the St. Lucie Unit 2 30% Steam Generator Tube Plugging and WCAP-9272 Reload Methodology submittal included a large delay in the feedwater isolation function where the feedwater isolation to the faulted loop steam generator occurred at 92.9 seconds into the transient. This included an assumption that neither of the redundant and independent feedwater isolation valves for the faulted loop steam generator closed within their Technical Specification requirement of 5.15 seconds from the low steam pressure signal on the faulted steam generator. Closure of either valve in 5.15 seconds following the ESF signal would result in feedwater isolation at 8.51 seconds into the transient. As a result, the 92.9 seconds of feedwater flow added over 152,000 lbm of water (full feedwater flow of approximately 1638 lbm/sec) to the faulted steam generator. The same feedwater flow for 8.51 seconds would add slightly less than 14,000 lbm of water.

To demonstrate the effects of the feedwater flow sensitivity on the results, a case was analyzed where the feedwater flow was terminated at the Technical Specification response time for feedwater isolation. The following comparisons are worth noting for the reference case (92.9 second feedwater isolation) and the sensitivity case (8.51 second feedwater isolation):

- The nuclear power calculated for the reference case begins increasing approximately 25 seconds earlier than the sensitivity case and remains significantly higher than the sensitivity case throughout the transient. The peak nuclear power reached for the reference case is approximately 18.2% of nominal power to the 12.5% reached for the sensitivity case.
- At the time of peak power for the sensitivity case (approximately 170 seconds into the transient), the difference in core average boron concentration is less than 0.1 ppm with the reference case at the slightly higher boron concentration.
- The nuclear power rise is terminated by dryout of the steam generator for both cases. Dryout occurs at approximately 170 seconds for the sensitivity case and 315 seconds in the reference case.

The reference case feedwater flow addition, which would be roughly equivalent to providing 1100% of nominal feedwater flow over the 8.51 second timeframe for feedwater flow in the sensitivity case, provides a conservative power transient for DNBR calculations and provides an extremely bounding addition of feedwater in comparison to any potential feedwater flow variations which could occur due to steam pressure effects. The additional feedwater flow provides a more significant impact on the nuclear power transient through the additional cooling and the delay in tube bundle uncovery as compared to the boron concentration transient and small variations in the boron initiation timing.

Enclosure 3

Non Proprietary Attachment

Attachment 10

Justification for Time Delay Between Turbine Trip and LOOP in Accident Analyses

Regulatory Background:

SRP 15.1.5 STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE OF CONTAINMENT (PWR), Revision 2, July 1981

"Assumptions as to the loss of offsite power and the time of loss should be made to study their effects on the consequences of the accident. A loss of offsite power may occur simultaneously with the pipe break, or during the accident, or offsite power may not be lost. Analyses should be made to determine the most conservative assumption appropriate to the particular plant design. The analyses should take account of the effect that loss of offsite power has on reactor coolant pump and main feedwater pump trips and on the initiation of auxiliary feedwater flow, and the effects on the sequence of events for these accidents."

15.3.3 – 15.3.4 REACTOR COOLANT PUMP ROTOR SEIZURE AND REACTOR COOLANT PUMP SHAFT BREAK, Revision 2, July 1981

"This event should be analyzed assuming turbine trip and coincident loss of offsite power and coastdown of undamaged pumps. The applicant's analysis should be performed using an acceptable analytical model."

Westinghouse's Regulatory Perspective

Based on general design criteria (GDC) 17, there is no specified basis for assuming an instantaneous LOOP.

Based on SRP 15.1.5, Section II.C.6.b

"A loss of offsite power may occur simultaneously with the pipe break, or during the accident, or offsite power may not be lost. Analyses should be made to determine the most conservative assumption appropriate to the particular plant design."

- Thus, if a plant specific design shows that (based on grid stability) a time delay is justifiable, then it is acceptable to be used in the plant specific safety analyses.

Based on SRP 15.3.3-4, Section II.C.10

"This event should be analyzed assuming turbine trip and coincident loss of offsite power and coastdown of undamaged pumps. The applicant's analysis should be performed using an acceptable analytical model. The equations, sensitivity studies, and models described in References 8 through 12 are acceptable.

- Although the SRP is specific regarding the time of loss of offsite power, the NRC has approved the use of a time delay in the safety analyses of the locked rotor event. The time delays have been based on plant specific grid stability analyses for Westinghouse designed plants.

CE interpretation

For St. Lucie - It was conservatively assumed that reactor trip for a steam line break with a loss of offsite power would both occur simultaneously. For a Locked Rotor, a loss of offsite power could occur with a time delay on 3.4 seconds following reactor trip (3.0 seconds following turbine trip).

In the current NRC review, the NRC states that "The SRP dictates that LOAC be assumed to occur at the worst time during MSLB event."

Note - the GDC does not specify a specific time requirement and the SRP for SLB does not specify a zero time requirement while the SRP for locked rotor infers a coincident LOOP, but a 3.4 second time delay was accepted.

Westinghouse Interpretation

For the Westinghouse plants, the position has been that an appropriate time delay from turbine trip to LOOP is acceptable, provided it can be justified. This is applicable for all the Chapter 15 analyses. For perspective, it is common to assume 2-3 second time delay for Westinghouse designed plants.

Conclusion

The NRC has accepted 2-3 second delay for Westinghouse plants and a 3.0 second time delay (turbine trip to LOOP) for St. Lucie Unit 2 for the locked rotor event, when the SRP identifies a "coincident LOOP" assumption. The time delays for Westinghouse methodology is based on plant-specific grid stability analyses. St. Lucie Unit 2 has performed a plant-specific grid stability analysis, which justifies a 3.3-second delay. In addition, St. Lucie Unit 2 is now applying the Westinghouse methods. Therefore, it should be acceptable to assume a 3-second time delay for other events such as the MSLB and feedline break events where the SRP is less specific regarding the timing of LOOP.

Enclosure 4

Westinghouse Affidavit supporting

Proprietary Portions of Enclosure 2A

And

Attachments 3A and 4A of Enclosure 3

Enclosure 2A and Attachments 3A and 4A of Enclosure 3 contain 10 CFR 2.390(a)(4) Proprietary Information

CAW-04-1873

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

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

Sworn to and subscribed
before me this 12th day
of August, 2004

Lorraine M. Piplica
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Lorraine M. Piplica, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Dec. 14, 2007
Member, Pennsylvania Association Of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse application for withholding accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked "Final RAIs on St. Lucie Unit 2 Reload Methodology/30% Tube Plugging License Amendment (TAC No. MC1566)" (Proprietary), for review and approval in support of NRC's Request for Additional Information, being transmitted by the Florida Power & Light Company letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for St. Lucie Unit 2 is expected to be used in response to certain NRC requirements for justification of the RAIs on St. Lucie Unit 2 Reload Methodology/30% Tube Plugging License Amendment (TAC No. MC1566) (Proprietary).

This information is part of that which will enable Westinghouse to:

(a) Provide technical information in support of NRC's request for additional information.

(b) Assist customer to obtain license change.

Further this information has substantial commercial value as follows:

(a) Westinghouse can use this information to further enhance their licensing position with their competitors.

(b) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar analyses and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

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