January 31, 2005

Mr. J. A. Stall
Senior Vice President, Nuclear and
Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE PLANT, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING CHANGE IN RELOAD METHODOLOGY AND INCREASE IN STEAM GENERATOR TUBE PLUGGING LIMIT (TAC NO. MC1566)

Dear Mr. Stall:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 138 to Renewed Facility Operating License No. NPF-16 for the St. Lucie Plant, Unit No. 2. This amendment consists of changes to the Technical Specifications in response to your application dated December 2, 2003, as supplemented by letters dated September 14 and December 10, 2004, and January 7, 2005.

This amendment permits operation with a reduced reactor coolant system flow corresponding to a steam generator tube plugging level of 30 percent per steam generator. The analyses performed to support this change utilize the Westinghouse Reload Safety Evaluation Methodology (WCAP-9272). This amendment also includes the transition to WCAP-9272 as the reload analysis methodology for St. Lucie Unit 2.

The amendment proposes a change in fuel design to use ZIRLO™ fuel pin cladding for new fuel. Use of ZIRLO™ clad fuel will be subject to the following license condition:

> The use of ZIRLO™ clad fuel at St. Lucie Unit 2 will be subject to the following restrictions:
>
> FPL [Florida Power & Light Company] will limit the fuel duty for St. Lucie Unit 2 to a baseline modified Fuel Duty Index (mFDI) of 600 with a provision for adequate margin to account for variations in core design (e.g., cycle length, plant operating conditions, etc). This limit will be applicable until data is available demonstrating the performance of ZIRLO™ cladding at Combustion Engineering [CE] 16x16 plants.
>
> FPL will restrict the mFDI of each ZIRLO™ clad fuel pin to 110 percent of the baseline mFDI of 600.
>
> For a fraction of the fuel pins in a limited number of assemblies (8), FPL will restrict the fuel duty of ZIRLO™ clad fuel pins to 120 percent of the baseline mFDI of 600.

FPL shall not lift the ZIRLO™ mFDI restriction discussed above without either NRC approval of a supplement to CENPD-404-P-A that includes corrosion data from two CE plants (not at the same site) or NRC approval of St. Lucie Unit 2 plant-specific corrosion data.

In support of this amendment, the staff performed a limited review of your request to adopt the alternate source term for radiological consequence analyses, contained in your submittal dated September 18, 2003, as supplemented by letters dated September 21 and September 24, 2004, and January 7, 2005. Based on this limited review, this amendment also permits a change in the St. Lucie Unit 2 licensing basis to use alternate source term in the radiological consequence analysis of the steam generator tube rupture event. The use of alternate source term for other accidents is not authorized, since staff review of those portions of your submittals is not complete.

Please note that the staff's approval is also based, in part, on licensee commitments to revise plant procedures that address changing meteorological conditions, isolating steam generators during accident conditions, and calculation of steam generator tube leakage, and to implement measures to monitor the availability of the transmission system operator contingency analysis program and to verify the switchyard voltages subsequent to any St. Lucie reactor trip, as discussed in the Safety Evaluation. The procedure changes will be in place prior to implementation of this amendment. The measures related to the transmission system operator contingency analysis program and the switchyard voltages will be in place 60 days after startup from refueling outage SL2-15.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Brendan T. Moroney, Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-389

Enclosures:
1. Amendment No. 138 to NPF-16
2. Safety Evaluation

cc w/enclosures: See next page

> FPL shall not lift the ZIRLO™ mFDI restriction discussed above without either NRC approval of a supplement to CENPD-404-P-A that includes corrosion data from two CE plants (not at the same site) or NRC approval of St. Lucie Unit 2 plant-specific corrosion data.

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Please note that the staff's approval is also based, in part, on licensee commitments to revise plant procedures that address changing meteorological conditions, isolating steam generators during accident conditions, and calculation of steam generator tube leakage, and to implement measures to monitor the availability of the transmission system operator contingency analysis program and to verify the switchyard voltages subsequent to any St. Lucie reactor trip, as discussed in the Safety Evaluation. The procedure changes will be in place prior to implementation of this amendment. The measures related to the transmission system operator contingency analysis program and the switchyard voltages will be in place 60 days after startup from refueling outage SL2-15.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/RA/
Brendan T. Moroney, Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-389
Enclosures:
1. Amendment No. 138 to NPF-16
2. Safety Evaluation

cc w/enclosures: See next page

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Florida Power and Light Company

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FLORIDA POWER & LIGHT COMPANY

ORLANDO UTILITIES COMMISSION OF

THE CITY OF ORLANDO, FLORIDA

AND

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. 50-389

ST. LUCIE PLANT UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 138
Renewed License No. NPF-16

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Florida Power & Light Company, et al. (the licensee), dated December 2, 2003, as supplemented by letters dated September 14 and December 10, 2004, and January 7, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, Renewed Facility Operating License No. NPF-16 is amended by changes to the Renewed Operating License and Technical Specifications as indicated in the attachment to this license amendment, and by amending paragraph 3.B to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 138, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 60 days of the date of issuance. Revisions to plant procedures that address changing meteorological conditions, isolating steam generators during accident conditions, and calculation of steam generator tube leakage, as discussed in the Safety Evaluation, shall be in place prior to implementation. The procedures that address the transmission system operator contingency analysis program, as discussed in the Safety Evaluation, shall be in place 60 days after startup from refueling outage SL2-15.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Michael L. Marshall, Jr., Chief, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical Specifications
and Renewed Operating License

Date of Issuance: January 31, 2005

<u>ATTACHMENT TO LICENSE AMENDMENT NO. 138</u>

<u>TO RENEWED FACILITY OPERATING LICENSE NO. NPF-16</u>

<u>DOCKET NO. 50-389</u>

Replace page 5 of Renewed Operating License No. NPF-16 with the attached pages 5 and 6.

Replace the following pages of the Appendix "A" Technical Specifications with the attached pages. The revised pages are identified by amendment number and contain vertical lines indicating the area of change.

Remove Pages	Insert Pages
II	II
V	V
XVII	XVII
1-7	1-7
2-3	2-3
2-5	2-5
2-9	2-9
3/4 1-5	3/4 1-5
3/4 2-2	3/4 2-2
----	3/4 2-2a
3/4 2-7	3/4 2-7
3/4 2-8	3/4 2-8
3/4 2-13	3/4 2-13
3/4 2-15	3/4 2-15
3/4 4-19	3/4 4-19
3/4 10-2	3/4 10-2
5-3	5-3
5-4	5-4
6-20	6-20
6-20d	6-20d
6-20e	6-20e

G. Before engaging in additional construction or operational activities which may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement dated April 1982, FPL shall provide written notification to the Office of Nuclear Reactor Regulation.

H. FPL shall report any violations of the requirements contained in Section 3, Items A, D, F, and G of this license within 24 hours by telephone and confirm by telegram, mailgram, or facsimile transmission to the NRC Regional Administrator, Region II, or his designee, no later than the first working day following the violation, with a written follow-up report within fourteen (14) days.

I. FPL shall notify the Commission, as soon as possible but not later than one hour, of any accident at this facility which could result in an unplanned release of quantities of fission products in excess of allowable limits for normal operation established by the Commission.

J. FPL shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

K. The use of ZIRLO™ clad fuel at St. Lucie Unit 2 will be subject to the following restrictions:

FPL will limit the fuel duty for St. Lucie Unit 2 to a baseline modified Fuel Duty Index (mFDI) of 600 with a provision for adequate margin to account for variations in core design (e.g., cycle length, plant operating conditions, etc). This limit will be applicable until data is available demonstrating the performance of ZIRLO™ cladding at Combustion Engineering 16x16 plants.

FPL will restrict the mFDI of each ZIRLO™ clad fuel pin to 110 percent of the baseline mFDI of 600.

For a fraction of the fuel pins in a limited number of assemblies (8), FPL will restrict the fuel duty of ZIRLO™ clad fuel pins to 120 percent of the baseline mFDI of 600.

FPL shall not lift the ZIRLO™ mFDI restriction discussed above without either NRC approval of a supplement to CENPD-404-P-A that includes corrosion data from two Combustion Engineering plants (not at the same site) or NRC approval of St. Lucie Unit 2 plant-specific corrosion data.

4. This renewed license is effective as of the date of issuance, and shall expire at midnight April 6, 2043.

FOR THE NUCLEAR REGULATORY COMMISSION

Original signed by

J. E. Dyer, Director
Office of Nuclear Reactor Regulation

Attachments:
1. Appendix A, Technical Specifications
2. Appendix B, Environmental Protection Plan
3. Appendix C, Antitrust Conditions
4. Appendix D, Antitrust Conditions

Date of Issuance: October 2, 2003

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 138

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-16

FLORIDA POWER AND LIGHT COMPANY, ET AL.

ST. LUCIE PLANT, UNIT NO. 2

DOCKET NO. 50-389

1.0 INTRODUCTION

By letter to the U.S. Nuclear Regulatory Commission (NRC) dated December 2, 2003, as supplemented by letters dated September 14 and December 10, 2004, and January 7, 2005, Florida Power and Light Company, et al., (FPL, the licensee) requested to amend Renewed Operating License NPF-16 for St. Lucie Unit 2, by revising the Technical Specifications (TSs). The proposed amendment would permit operation with a reduced reactor coolant system (RCS) flow corresponding to a steam generator (SG) tube plugging (SGTP) level of 30 percent per SG. The analyses performed to support this change utilize the Westinghouse Reload Safety Evaluation Methodology (WCAP-9272). This amendment includes the transition to WCAP-9272 as the reload analysis methodology for St. Lucie Unit 2.

The licensee's supplementary submittals dated September 14 and December 10, 2004, and January 7, 2005, provided clarifying information that did not change the scope of the proposed amendment as described in the original notice of proposed action published in the *Federal Register* and did not change the initial proposed no significant hazards determination.

For the dose consequence analysis of this amendment, the licensee proposed to credit the use of alternate source term (AST), which was requested in a separate submittal dated September 18, 2003, and supplemented on September 21 and September 24, 2004. The licensee expected to have AST fully approved in time to support this amendment. However, the NRC staff review of the AST submittal has not been completed. Therefore, following discussions with the staff, the licensee supplemented the AST submittal with a letter dated January 7, 2005, which provided information to allow the staff to focus on those design basis events necessary to support approval of the amendment for revising core methodologies and SGTP.

2.0 REGULATORY EVALUATION

2.1 Regulatory Requirements Addressed in the Evaluation in Section 3.0

In the current licensing basis for St. Lucie Unit 2, the licensee is required to perform analyses of applicable loss-of-coolant accidents (LOCAs) and non-LOCAs using NRC approved methods to support its proposed amendments and associated TS changes. The results of analyses must demonstrate compliance with General Design Criterion (GDC) 10, "Reactor Design," for fuel limits; GDC 15, "Reactor Coolant System Design," for reactor coolant pressure boundary pressure limits during non-LOCA transients; and Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.46 for the emergency core cooling system performance during LOCA events. The guidance for implementing the requirements of GDC 10 and 15 and 10 CFR 50.46 related to the design-basis event analyses and the acceptance criteria is provided in Chapter 15, "Accident Analysis," of NUREG-0800, the NRC's Standard Review Plan (SRP). To be consistent with the current licensing basis, the review of the LOCA and non-LOCA analyses for the St. Lucie Unit 2 proposed amendment is based on the guidance specified in Chapter 15 of the SRP for the non-LOCA analyses and 10 CFR 50.46 requirements for the LOCA analyses.

For TS changes related to the core operating limits report (COLR) implementation, Generic Letter (GL) 88-16 (Reference 9) requires that the parameters to be relocated to the COLR be cycle-specific and be calculated using approved methods, with these methods listed in the Administrative Control Section of the TSs.

Also, 10 CFR 50.36, "Technical specifications," specifies the regulatory requirements related to the content of TSs. Since the Standard TSs were developed based on the 10 CFR 50.36 requirements and St. Lucie Unit 2 uses the Combustion Engineering (CE)-designed nuclear steam supply system, the NRC staff utilized NUREG-1432, "Standard Technical Specifications-Combustion Engineering Plants" (Reference 10), in its review of the proposed TSs (Reference 4) for St. Lucie Unit 2.

In this review, the staff evaluated the acceptability of the Westinghouse non-LOCA methodologies for the St. Lucie Unit 2 application and confirmed that the results of non-LOCA and LOCA analyses are in compliance with the requirements of GDC 10 and15 and 10 CFR 50.46, based on the guidance provided in Chapter 15 of the SRP. Also, the staff evaluated TS changes for COLR implementation in accordance with the GL 88-16 guidelines.

GDC 17 requires that a loss of offsite power (LOOP) must be considered in the analysis of anticipated operational occurrences (AOOs) and accidents. Implementation of the GDC requirements for the LOOP time is specified in the SRP guidance for three non-LOCA events: steam line break (SLB), feedwater line break (FLB) and locked rotor events. In general, the guidance states that a licensee is requested to search for the worst time of LOOP, the conservative approach, but does not provide further specifics.

Specifically, the SRP states for SLB and FLB that:

> 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 accidents. 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 sequences of events for these accidents.

For the locked rotor event, the SRP states that:

> 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.

2.2 Regulatory Requirements Addressed in the Evaluation in Section 4.0

In December 1999, the NRC issued 10 CFR 50.67, “Accident Source Term,” to provide a mechanism for licensed power reactors to replace the traditional accident source term used in their design basis accident analyses with an AST. Regulatory guidance for the implementation of these ASTs is provided in Regulatory Guide (RG) 1.183. A licensee seeking to use an AST is required, pursuant to 10 CFR 50.67, to apply for a license amendment. An evaluation of the consequences of affected design basis accidents (DBAs) is required to be included with the submittal. In accordance with the guidance in RG 1.183, a licensee is not required to reanalyze all DBAs for the purpose of the application, just those affected by the proposed changes. The licensee’s application addresses these requirements in proposing to use the AST described in RG 1.183 as the source term in the evaluation of the radiological consequences of the SGTR DBA at St. Lucie Unit 2.

This safety evaluation addresses the impact of the proposed changes on previously analyzed DBA radiological consequences and the acceptability of the revised analysis results. According to the licensee, only the SGTR DBA is impacted. Other DBAs remain bounding with the 30 percent tube plugging amendment. Therefore, the regulatory requirements on which the staff based its acceptance of the SGTR DBA are the accident dose criteria in 10 CFR 50.67, as supplemented in Regulatory Position 4.4 of RG 1.183 and GDC 19. Except where the licensee has proposed a suitable alternative, the staff used the regulatory guidance in the following documents in doing this review:

- RG 1.145, “Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants”
- RG 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”
- Draft RG DG-1111, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants”
- SRP Section 2.3.4, “Short-Term Diffusion Estimates for Accidental Atmospheric Releases”

2.3 Regulatory Requirements Addressed in the Evaluation in Section 5.0

GDC 17, in Appendix A to 10 CFR Part 50, specifies that an onsite electric power system be provided to permit functioning of structures, systems, and components important to safety following anticipated operational occurrences and postulated accidents. GDC 17 requires this capability for the onsite electric power system, assuming the offsite electric power system is not functioning; but does not specify how the offsite power system could be lost.

NRC SRP guidance for determining the time of a LOOP is specified for the analysis for four events: main SLB, FLB, reactor coolant pump (RCP) locked rotor, and LOCA events. In general, the guidance states that a licensee is supposed to search for the worst time of LOOP but does not provide further specifics.

SLB and FLB

> 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 accidents. 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 sequences of events for these accidents.

RCP Locked Rotor

> 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 NRC has permitted licensees to deviate from this guidance. The decision to allow the delay for the RCP locked rotor event was made back in the 1980's at the request of the industry because the acceptance criteria in the SRP could not be met without removal of this conservatism. At present, no other plant credits this delay for the main SLB event.

3.0 TECHNICAL EVALUATION - 30-PERCENT SGTP AND CORE METHODOLOGY CHANGE

In the request for approval of operation of St. Lucie Unit 2 with a maximum SGTP level of 30 percent in each of the two SGs, the licensee provided supporting information in Reference 1 for the staff to review. Reference 1 includes seven attachments: Attachment 1 (Reference 3) provides a description of the proposed changes and supporting justification; Attachment 2 contains information related to determination of no significant hazards consideration; Attachments 3 and 5 (Reference 4) consist of marked-up and retyped copies of the TS changes; Attachment 4 includes information only copies of St. Lucie Unit 2 marked-up TS bases and COLR pages; Attachment 6 (Reference 5) contains a licensing report documenting the non-LOCA analysis performed with the Westinghouse reload methodology discussed in WCAP-9272 and the LOCA analysis performed with the CE LOCA evaluation models for supporting the St. Lucie Unit 2 operation with 30-percent SGTP; and Attachment 7 (Reference 6) provides the proprietary portions of Westinghouse licensing report described in Reference 5.

The staff review is to confirm that the licensee performed safety analyses with acceptable methods, to verify that the analytical results meet the required acceptance criteria and to ensure that the proposed TSs appropriately reflect the results of the acceptable safety analyses. The following evaluation is based on the staff review of the proposed amendment and its associated TS changes with supporting analyses documented in Reference 1 and its attachments, and the licensee's responses (References 7, 8 and 20) to the staff's request for additional information (RAI). This evaluation includes the staff's review for the following areas: (1) fuel design, (2) nuclear design, (3) analytical methods, (4) non-LOCA transients analyses, (5) LOCA analyses, and (6) the proposed TS changes.

3.1 Fuel Design

The fuel system mechanical design of St. Lucie Unit 2 consists of 16x16 CE HID-1L fuel with zircaloy-4 and ZIRLO cladding. The licensee will begin using fuel with ZIRLO cladding in Cycle 15. There are no significant changes in the fuel design other than the transition to the ZIRLO cladding. The use of ZIRLO cladding was approved in the topical report CENPD-404-P-A (Reference 13), "Implementation of ZIRLO Cladding Material in CE Nuclear Power Fuel Assembly Designs."

The fuel system consists of fuel rods, spacer grids, guide thimbles, top and bottom end plates, and reactivity control rods including burnable poison rods. The NRC staff review uses the following criteria to evaluate the fuel system design: (1) the fuel system is not damaged as a result of normal operation and AOOs, (2) fuel system damage is never so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. The NRC staff's review covers fuel system damage mechanisms, failure mechanisms, and safety of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on (1) 10 CFR 50.46 for core cooling, (2) GDC 10 for assuring that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including AOOs, (3) GDC 27 for the reactivity control system being designed with appropriate margin, and in conjunction with the ECCS, being capable of controlling reactivity and cooling the core under post-accident conditions, and (4) GDC 35 for providing an emergency core cooling system (ECCS) to transfer heat from the reactor core following any loss of reactor coolant. Specific review criteria are contained in SRP Section 4.2.

Rod Internal Pressure

Rod internal pressure is considered a driving force for fuel system damage that could contribute to the loss of dimensional stability and cladding integrity. The staff has approved a rod pressure limit that can exceed the system pressure provided that the fuel-to-cladding gap remains closed (i.e., no clad liftoff for CE fuel designs).

The licensee performed a bounding analysis using the approved fuel performance code FATES3B. The result showed that the maximum predicted rod pressure was below the critical pressure limit for clad liftoff. Based on the approved methodology, the staff considers that the rod internal pressure analysis is acceptable for St. Lucie Unit 2.

Clad Stress and Strain

Section 4.2 of the SRP states that the stress and strain limits in fuel designs should not be exceeded for normal operations and AOOs. During operation with 30-percent SGTP, the fuel system could experience elevated temperatures, thereby exceeding the stress and strain limits, for certain AOOs.

The licensee re-analyzed the fuel system loading using the approved FATES3B code to analyze the stress and strain conditions. The results showed that the stress and strain limits were not exceeded. Based on the approved methodology and acceptable analyses, the staff concludes that the fuel system design meets the stress and strain limits for St. Lucie Unit 2.

Fuel Melting

Section 4.2 of the SRP states that the fuel centerline temperature shall not exceed the fuel melting temperature for normal operations and AOOs. During operation with 30 percent SGTP, the fuel system could experience high temperature, thereby exceeding the fuel melting temperature, for certain AOOs.

The licensee re-examined the fuel system loading using the approved FATES3B code to analyze the temperature condition. The results showed that the fuel centerline temperature will not exceed the melting temperature. Based on the acceptable analysis, the staff concludes that the fuel system design meets the fuel centerline temperature limit for St. Lucie Unit 2.

Strain Fatigue

The fuel rod strain fatigue capability could be impacted by the SGTP. The approved analysis of strain fatigue is based on the O'Donnell and Langer curve, as described in Section 4.2 of the SRP.

The licensee re-analyzed the strain fatigue capability using the O'Donnell and Langer curve. The result showed that the fuel system design maintained its strain fatigue capability. Based on the acceptable analysis, the staff concludes that the strain fatigue capability is acceptable for St. Lucie Unit 2.

Cladding Oxidation

Section 4.2 of the SRP identifies cladding oxidation buildup as a potential damage mechanism for fuel designs. The SRP further states that the effect of cladding oxidation needs to be addressed in safety and design analyses, such as in the thermal and mechanical analysis. In the approved CENPD-404-P-A methodology, the staff required that the corrosion limit remain below 100 microns for all locations of the fuel rod.

The licensee performed a bounding analysis that showed that the maximum corrosion was within the established limit of 100 microns with the current and planned coolant chemistry conditions. Based on the acceptable results, the staff concludes that the impact of corrosion on the thermal and mechanical performance will be minimal for St. Lucie Unit 2.

Fuel Duty

Recently, licensees have requested approval of higher power ratings, extended burnups, and higher operating temperatures leading the industry to aggressively pursue core designs of high fuel duty. The high fuel duty core is generally characterized by high fuel rod surface temperature, subcooled boiling, high power density, and longer residence time. In the approved CENPD-404-P-A methodology, the staff requires that the fuel duty be restricted until data become available in demonstrating feasibility of high fuel duty cycle.

The licensee confirmed that the St. Lucie Unit 2 fuel duty remained within the current data base.

In a telephone call on January 27, 2005, the licensee agreed to accept the following license condition regarding the use of ZIRLO^{TM} clad fuel at St. Lucie Unit 2:

> The use of ZIRLO^{TM} clad fuel at St. Lucie Unit 2 will be subject to the following restrictions:
>
> FPL will limit the fuel duty for St. Lucie Unit 2 to a baseline modified Fuel Duty Index (mFDI) of 600 with a provision for adequate margin to account for variations in core design (e.g., cycle length, plant operating conditions, etc). This limit will be applicable until data is available demonstrating the performance of ZIRLO^{TM} cladding at Combustion Engineering 16x16 plants.
>
> FPL will restrict the mFDI of each ZIRLO^{TM} clad fuel pin to 110 percent of the baseline mFDI of 600.
>
> For a fraction of the fuel pins in a limited number of assemblies (8), FPL will restrict the fuel duty of ZIRLO^{TM} clad fuel pins to 120 percent of the baseline mFDI of 600.
>
> FPL shall not lift the ZIRLO^{TM} mFDI restriction discussed above without either NRC approval of a supplement to CENPD-404-P-A that includes corrosion data from two Combustion Engineering plants (not at the same site) or NRC approval of St. Lucie Unit 2 plant-specific corrosion data.

Based on the licensee's acceptance of the above license condition, the staff concludes that the fuel duty concern is adequately addressed for St. Lucie Unit 2.

LOCA Analysis

In the approved CENPD-404-P-A methodology, the staff stated that if the CENP LOCA methodologies and/or constituent models are changed in the future, documentation supporting the changes should include justification of the continued applicability of the methodology or model to ZIRLO. The licensee indicated that the CENP LOCA methodologies and constituent models used in the SGTP LOCA analyses did not change from the evaluation models described in the approved CENPD-404-P-A.

The staff reviewed the response and concludes that the licensee's compliance is acceptable for St. Lucie Unit 2.

Seismic/LOCA Impact on Fuel Assemblies

Earthquakes and postulated pipe breaks in the reactor coolant system would result in external forces on fuel assemblies. Appendix A to SRP Section 4.2 states that fuel system coolability should be maintained and damage should not be so severe as to prevent control rod insertion when required during seismic and LOCA events. Fuel assemblies are analyzed for structural components - mainly grid spacers - to ensure that external forces do not exceed the maximum allowable grid crushing load such that the resulting damage is minimal, and control rods and thimble tubes remain functional during seismic and LOCA events.

In Section 2.5 of Reference 5, the licensee indicated that the use of ZIRLO cladding in the 16x16 HID-1L fuel did not change the fuel system grid and guide thimble designs in St. Lucie Unit 2. The reduced RCS flow would have no impact on the seismic/LOCA evaluation. Thus, the licensee concluded that there was no grid deformation and the coolable geometry was maintained under the seismic and LOCA events. In reviewing the approved CENPD-404-P-A, which describes the use of ZIRLO under seismic/LOCA conditions, the staff agrees with the licensee's assessment.

Based on the approved methodology, the staff concludes that the grid impact analysis is acceptable and the coolable geometry will be maintained during the seismic/LOCA events for St. Lucie Unit 2.

In summary, the staff has reviewed the licensee's submittal of the fuel system mechanical design related to the SGTP for St. Lucie Unit 2. Based on the evaluation, the staff concludes that the fuel system mechanical design including the use of ZIRLO cladding is acceptable for St. Lucie Unit 2 to the rod average burnup of 60,000 MWd/MTU. The staff also concludes that the licensee has demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained.

3.2 Nuclear Design

This section documents the NRC staff's evaluation of the licensee's proposed TS changes pertaining to the non-LOCA physics aspects of the Reference 5 submittal.

Section 4.3 of the SRP provides the basis for the staff's requirements regarding nuclear design. The review of the nuclear design includes the fuel assemblies, control systems and reactor core, and is carried out to confirm that fuel design limits will not be exceeded during normal operation or AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary or impair the capability to cool the core.

Significant levels of tube plugging have the potential to affect the core power distribution and reactivity due to perturbations imposed on the RCP flow rate and coolant temperature distribution. The licensee evaluated the impacts of 30 percent SGTP on nuclear design using NRC-approved Westinghouse design methods. The reload analysis process involves analyses of cycle-specific three-dimensional core power distribution to determine the core design's sensitivity to control and power-shaping rod positions, power level, fuel burnup, and Xenon distribution. Additionally, nuclear parameter analyses are performed to calculate reactivity coefficients, rod worths, boron requirements, and other parameters necessary to ensure that the safety analysis remains valid for the reload core.

The NRC staff has reviewed the impacts of 30-percent SGTP on core physics and finds them to be acceptable. NRC approved methods were used to perform these analyses and the impacts of 30-percent tube plugging were determined to be insignificant. Therefore, the acceptance criteria for nuclear design continue to be satisfied. Future St. Lucie Unit 2 core reload designs and analyses will continue to be performed using NRC-approved methods, thus ensuring that all acceptance criteria will continue to be satisfied.

Relaxation of Axial Offset Control (RAOC)

As part of the original submittal of Reference 5, the licensee requested the application of the NRC approved Westinghouse relaxed axial offset control methodology (Reference 14), "Relaxation of Constant Axial Offset Control; F_Q Surveillance Technical Specification," to evaluate axial power distributions at St. Lucie Unit 2. The result of the RAOC procedure is a curve of allowed axial shape index (ASI - difference between the lower and upper excore detector readings) as a function of power. The RAOC procedure requires that the allowed ASI be bounded by those used in the analysis for LOCA events and non-LOCA Condition II events. With the RAOC implemented, a TS must be established to require that the ASI be maintained within the acceptable band as a function of power.

In Reference 5, the licensee did not submit an actual analysis demonstrating the applicability of RAOC during the next operating cycle (Cycle 15) of St. Lucie Unit 2. Instead, it submitted a representation of Cycle 15 first application of the RAOC methodology to St. Lucie Unit 2. The actual Cycle 15 calculations will be performed as part of the reload evaluation process for Cycle 15 (and subsequent cycles). A representative design for Cycle 15 was used as a "test" of the expected performance of the RAOC methodology in advance of the Cycle 15 design.

The process of identification of bounding values for the key reload parameters has been maintained by establishing a set of baseline neutronics for use in the safety analyses. These values and the key parameters themselves have been adjusted only slightly from a standard application for a Westinghouse application to accurately model the unique features of the St. Lucie Unit 2 plant, trips, and TSs (References 5 and 6 on page 3-4 of Reference 5). The values established for the baseline neutronics were chosen to be sufficiently conservative to preclude violations in the reload evaluation process without being overly conservative.

For the key parameters, thermal and neutronic limits were established based on recent past operation of St. Lucie Unit 2 to identify representative parameter values. From these representative values, limiting values for use in the safety analyses were established with due consideration of the existing analysis assumptions, extensive plant and design experience, and accounting for changes in SGTP, minimum TS flow and cladding material transition. The effect of coastdowns to extend the cycle length beyond nominal full-power capability was also considered in determination of the key safety parameters.

Table 3-1 of Reference 5 provided the key safety parameter ranges for the upcoming cycle (Cycle 15) and compared them to the current thermal and neutronic limits. As noted in Table 3-1, the limit for the peak (LHR) for normal operation was reduced from 13.0 Kw/ft to 12.5 Kw/ft. The licensee indicated that although the reduced peak LHR COLR limit reduces nuclear design flexibility, it was required to satisfy the acceptance criteria of 10 CFR 50.46 for a large-break LOCA. Analysis performed by the licensee indicated that higher limits for peak LHR are supportable from a neutronics design perspective, and that they may be addressed in future reloads on a cycle-specific basis.

With the reduction in peak LHR required to satisfy the requirements of 10 CFR 50.46

for large break LOCA (LBLOCA), the licensee performed studies with the reduced LHR limit to determine the impact on operating margin and core reload design. The representative design for Cycle 15 was run with a peak LHR limit of 12.5 kw/ft. The results of analysis of the representative Cycle 15 core design indicated that ASI limit violations existed at approximately 70-percent power (Section 3.6 of Reference 5). Consequently, both Figures 3.2.1, "Allowable Peak Linear Heat Rate vs. Burnup," and 3.2.2, "Axial Shape Index vs. Maximum Allowable Power level," in the COLR had to be modified to meet the reduced peak LHR requirement.

Constant monitoring for LHR with the Incore Detector Monitoring System (IDMS) addresses LHR considerations when the IDMS is used (COLR Figure 3.2-1). However, when using the Excore Detector Monitoring System (EDMS), the LHR reduction requires restriction of the allowable ASI (COLR Figure 3.2-2) based on this study. To address the peak LHR reduction, the allowable ASI limits were reduced by (1) shifting the positive ASI "wing" inward and reducing the breakpoint (power for maximum allowable ASI), and (2) reducing the breakpoint for the negative ASI.

Starting from this set of assumed ASI limits, the licensee performed RAOC calculations based on the following assumptions:

1. Use of the revised LHR Limiting Condition for Operation (LCO), as a proposed replacement for the current LHR LCO,

2. Application of a very conservative 8 percent uncertainty on ASI, and

3. A peak LHR limit of 12.5 kw/ft.

These calculations for a representative Cycle 15 reload design resulted in peak LHRs less than 12.5 kw/ft.

The licensee provided figures in Appendix A to Reference 5, namely Figures A-1 (COLR Figure 3.2-2) and A-2, representative of the upcoming Cycle 15 reload design based on the reduced LHR. In particular, Figure A-2 shows the flyspeck results (locus of limiting LHR data) of the final RAOC "test" calculations compared with the 12.5 kw/ft peak LHR limit currently proposed for Cycle 15. These results confirm the acceptability of the revised ASI limits for LHR when using the EDMS, COLR Figure 3.2-2, and the applicability of the Westinghouse RAOC methodology. The staff concurs with the results of the analysis.

The reduction in peak LHR was accomplished by using a part-power multiplier that is based on the St. Lucie Unit 2 plant-specific operating history information, and conservatively bounds the effects of reduced power operation on radial peaking, based on application of the standard nuclear design analytical models and methods. The licensee pointed out that a revision of the COLR LHR LCO is required to accommodate the reduced peak LHR limit.

The use of the CE linear ASI limits resulted in a nonlinear relationship for axial flux difference, causing the most challenging heat rates to be determined at lower powers (approximately 70 percent), with relatively large values of ASI. Hence, the ASI limits have been reduced at lower powers where LHRs are challenged with the relatively large values of ASI. Constant monitoring for LHR with the IDMS makes F_{xy} surveillance redundant when performing surveillance with incore detectors. Therefore F_{xy} surveillance for incore monitoring has been eliminated, consistent with previous changes for St. Lucie Unit 1. For excore monitoring, F_{xy} surveillance is replaced by LHR surveillance, with application of W(z) penalties. This is consistent with typical operation using Best Estimate Analyzer for Core Operations - Nuclear (BEACON) already in use at St. Lucie Unit 2. Because analytical margins are expected to be approximately the same for the application of the RETRAN-based non-LOCA methods compared to the current methods for evaluation of axial power distributions, the elimination of the full-power positive moderator temperature coefficient (MTC) will result in less challenge to bounding neutronic assumptions for the non-LOCA analyses to accommodate margin reductions due to decreased RCS flow. Based on the discussions above, the staff concludes that the licensee's use of methods documented in WCAP-10216-P-A is acceptable.

3.3 Methodologies for Non-LOCA Analyses

The licensee proposed to use the following methodologies for non-LOCA analyses:

3.3.1 Westinghouse Reload Evaluation Methodology

The Westinghouse reload evaluation methodology is documented in WCAP-9272-P-A (Reference 2). This method is based on the concept of a bounding analysis. The method assumes that the validity of the reference analysis is established for the reload core under consideration, on the basis that the key safety parameters for the reload core use values that are conservatively bounded by those in the reference analysis. For each reload core, the values of the key safety parameters are examined to determine whether a transient analysis is required or not. If all key safety parameters are conservatively bounded, the reference safety analysis remains valid for the reload core. If a reload parameter is not bounded, further analysis or evaluation is required for the reload core. The methodology was previously approved (Reference 2) by the NRC for Westinghouse plants in performing 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. When the licensee used the WCAP-9272 methodology for reload applications, it established (see the response to RAI-8.a discussed in Reference 7) the limiting directions for the reactivity feedback parameters that are applicable to operation of St. Lucie Unit 2 with a maximum SGTP of up to 30 percent, including the effects of asymmetric SGTP. Since the reload evaluation methodology is sensitive to the set of computer codes and methods of analysis being applied, the staff's safety evaluation (SE) approving the methodology requires that any significant change in methods or codes by Westinghouse must be evaluated for its impact on the reload SE methodology of WCAP-9272. In addressing the SE restriction, the licensee proposed to use the NRC-approved Westinghouse methods and codes to perform its reload analysis. The staff evaluation (discussed in Sections 3.3.2 through 3.3.4 below) determines that the Westinghouse methods and codes are acceptable for St. Lucie Unit 2 licensing applications. Therefore, the staff concludes that the licensee's use of the Westinghouse reload methodology satisfies the SE restriction and is acceptable.

3.3.2 Revised Thermal Design Procedure for Thermal-Hydraulic Analyses

The licensee proposed to use the revised thermal design procedure (RTDP) to perform statistical core thermal-hydraulic analyses. Unlike the deterministic method, in which the uncertainties of various plant and operating parameters are assumed simultaneously at their worst uncertainty limits in the safety analyses, the RTDP methodology statically accounts for the system uncertainties in plant operating parameters, fabrication parameters, nuclear and thermal parameters, as well as the departure from nucleate boiling (DNB) correlation uncertainty. The RTDP methodology establishes an RTDP DNB ratio (DNBR) limit that statistically accounts for the effects on DNB of the key parameters. Therefore, when the RTDP methodology is used to perform thermal-hydraulic analyses, initial condition uncertainties are not included in the plant parameters that are sensitive to the DNBR calculations as they are already included in the RTDP DNBR limit. The RTDP methodology is documented in WCAP-11397-P-A (Reference 15).

The design DNBR limit must be calculated based on the system uncertainties in plant operating parameters and the uncertainties of the DNB correlation and computer codes used for the specific plant. In Reference 5, the licensee indicated that the RTDP in WCAP-11394-P-A and St. Lucie Unit 2 plant-specific uncertainties were used to determine the design DNBR limit. Specifically, the values of uncertainties were chosen (in Table 4-2 of Reference 5) to be consistent with those used in the current analysis for the following St. Lucie Unit 2 plant parameters: (1) the nuclear enthalpy rise hot channel factor, (2) the enthalpy rise engineering hot channel factor, (3) uncertainties in inlet flow distribution, cladding outside diameter, and rod pitch, and (4) uncertainties based on surveillance data associated with RCS flow, coolant temperature, pressure and reactor core power. The staff found that the licensee’s calculation of the design DNBR limit adequately follows the approved RDTP method described in WCAP-11397-P-A. Therefore, the staff concludes that the use of the RDTP as documented in WCAP-11397-P-A to perform statistical core thermal-hydraulic analyses for St. Lucie Unit 2 is acceptable.

3.3.3 Method for the Rod Ejection Analysis

As documented in WCAP-7588, Revision 1-A (Reference 19), the NRC has approved the method which relies on spatial kinetics models to perform the rod ejection analysis for the Westinghouse plants . As indicated in Appendix B of Reference 5, this methodology has also been applied and licensed in the analysis of the rod ejection event on CE-designed plants such as the Millstone 2 and Fort Calhoun Unit 1 plants. Therefore, the licensee’s application of this methodology to St. Lucie Unit 2 is acceptable.

3.3.4 Computer Codes Used for Non-LOCA Transient Analyses

The licensee proposed to perform non-LOCA analyses with the following computer codes:

3.3.4.1 VIPRE with the ABB-NV and W-3 Critical Heat Flux (CHF) Correlations

The VIPRE code is used to perform thermal-hydraulic analyses, determining coolant density, mass velocity, enthalpy, vapor void, static pressure and the DNBR distribution along parallel flow channels within the reactor core under normal operational and transient conditions. As documented in Section 4.2 of Reference 5, the licensee used the ABB-NV and W-3 critical heat flux correlations to calculate DNBRs.

The safety DNBR limits have been imposed to assure that there is at least a 95 percent probability at a 95 percent confidence level that the hot rods in the core do not experience a DNB during a transient. For CE 16x16 fuel assemblies in the St. Lucie Unit 2 reactor core, the licensee used the VIPRE code and the ABB-NV correlation with a correlation limit of 1.13 for the DNBR analysis. The ABB-NV correlation limit of 1.13 and the RTDP methodology documented in WCAP-11394-P-A are applied with St. Lucie Unit 2 specific data using the values of the thermal hydraulic parameters listed in Table 4-1 of Reference 5 and uncertainty factors listed in Table 4-2 of Reference 5 at the 95/95 probability/confidence level to define design DNBR limits. In DNBR analyses, the design DNBR limits are increased to provide DNB margin to offset the effect of rod bow and any other DNBR penalties that may occur, to provide flexibility in design and operation of the plant. The increased DNBR is referred to as the safety analysis limit (SAL) DNBRs as shown in Table 4-4 of Reference 5. The rod bow penalty included in the SAL DNBRs for the analysis of the 30 percent SGTP remains unchanged from the current value of 1.2 percent DNBR as discussed in Section 4.4.4.1 of the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR). The staff finds that: (1) the ABB-NV correlation with the associated 95/95 DNBR limit of 1.13 for CE 16x16 fuel assemblies was approved previously for use in Westinghouse VIPRE thermal-hydraulic code (Reference 18), and (2) the calculations of the design limit DNBRs adequately uses the acceptable RTDP methodology with the DNBR-parameter related uncertainties specific to the St. Lucie Unit 2 plant. Therefore, the staff concludes that the SAL DNBRs listed in Table 4-4 of Reference 5 are acceptable for the DNBR analyses for St. Lucie Unit 2.

As indicated in Section 4.2 of Reference 5 and the licensee's response to RAI-7 in Reference 7, the W-3 DNB correlation and standard thermal design procedure (STDP) were used in the DNBR analysis of the post-trip hot-zero power (HZP) SLB event. Specifically, the SAL DNBR limit used in VIPRE is 1.45 for RCS pressures within the range of 500 to 1000 psia. The STDP is the traditional design method with parameter uncertainties applied deterministically in the limiting direction. The SAL DNBR limit of the W-3 correlation with use of VIPRE in the SLB analysis was previously approved by the NRC for Westinghouse plants (Reference 17). The W-3 correlation was previously used (RAI-7 of Reference 7) in the Millstone 2, a CE-designed pressurized-water-reactor (PWR), FSAR analysis for both Westinghouse and CE fuel designs. Additional margin is also retained in the W-3 DNB safety analysis of the St. Lucie Unit 2 HZP SLB event in the form of a DNBR multiplier. Therefore, the staff concludes that use of the W-3 correlation with its associated SAL DNBR is acceptable for the St. Lucie Unit 2 SLB analysis.

3.3.4.2 RETRAN

RETRAN simulates a multi-loop system using a model containing a reactor vessel, hot- and cold-leg piping, SGs, and pressurizer. The code also includes point kinetics and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the SG uses a detailed nodalization for thermal transients. As documented in WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," the code was previously approved by the NRC for Westinghouse to analyze system responses to non-LOCA transients for Westinghouse PWRs.

The licensee used (Reference 5) RETRAN in performing analyses of the following events: (1) increase in feedwater flow rate, (2) decrease in feedwater temperature, (3) pre-trip and post-trip SLB events, (4) loss of condenser vacuum/turbine trip, (5) asymmetric SG transient (ASGT), (6) feedwater line break, (7) complete loss of forced flow, (8) reactor coolant pump seized rotor/shaft break, (9) uncontrolled rod withdrawal at power, (10) control element assembly (CEA) drop event, (11) Chemical and Volume Control System (CVCS) malfunction resulting in an increase in RCS inventory, and (12) inadvertent opening of the pressurizer relief.

All the events analyzed for St. Lucie Unit 2 using RETRAN, except the ASGT, are listed in the table of transients for which RETRAN has been approved for use (Reference 16). The limiting ASGT is the sudden closure of a main steam safety valve (MSSV) on one SG (or loss of load to one SG). Since the thermal-hydraulic response of the ASGT is within the range for events analyzed with RETRAN, such as the loss of load, turbine trip or SLB events, the use of RETRAN to analyze the ASGT for St. Lucie Unit 2 is acceptable.

The licensee provided in Appendix C of Reference 5 a detailed description of the RETRAN model developed to analyze a CE-designed plant with an analog protection system. As compared with the RETRAN model described in WCAP-14882-P-A for Westinghouse plants, two major changes were made. The changes are the accommodation of the two cold-legs per hot-leg configuration of the CE design and the replacement of the control and protection system processing logic applicable to St. Lucie Unit 2. The licensee included in RETRAN the following CE-designed plant logic and signal processing models for safety analyses: (1) power calculation, (2) thermal margin/low pressure reactor trip, (3) variable high power reactor trip, (4) pressurizer reactor trip functions, (5) RCS flow-related reactor trip function, (6) SG level trip functions, (7) turbine trip/manual reactor trips, (8) rate of change of power reactor trip function, (9) asymmetric SG steam pressure reactor trip function, (10) high local power density reactor trip, and (11) low SG pressure reactor trip.

The RETRAN input models include vessel mixing coefficients, which allow the user to change the amount of mixing that occurs in the coolant entering and exiting the core. Coolant mixing is important for analysis of events such as asymmetric cooldown that would occur as the result of the break of a single main steam line. Cooler water entering the core from the affected loop will cause space-dependent reactivity changes in the core, which, in turn, will affect the calculation of nuclear power. In Sections 3.2 and 3.4 of reference 6 and the response to RAI-27 of Reference 7, the licensee indicated that the mixing coefficients used in the applicable non-LOCA transient analyses were calculated from experimental data from a scaled mixing test for a CE-design reactor. Since the same test data were used for calculating mixing parameters used in the analysis of record (AOR) (see the response to RAI-27 of Reference 7), the staff determined that the use of the CE mixing test data for calculating the RETRAN mixing coefficients is acceptable.

Based on the review discussed above, the staff finds that: (1) the events analyzed using RETRAN are consistent with those listed in Table 1 of the staff's SE approving RETRAN, and (2) the CE plant design features applicable to St. Lucie Unit 2 are adequately incorporated in the RETAN models. Therefore, the staff concludes that the licensee's use of RETRAN in performing non-LOCA analysis for the St. Lucie Unit 2 plant is acceptable.

3.3.4.3 CESEC

This code calculates system parameters such as core power, flow, pressure, temperature, RCS inventory and valve actions during a transient. CESEC was used to analyze the SG tube rupture and primary line break out side containment events. This approach is the same as that used in the AOR and, therefore, is acceptable.

3.3.4.4 TWINKLE and FACTRAN

TWINKLE is a multi-dimensional spatial neutronics code which uses an implicit finite-difference method to solve the two group transient neutronics equations in one, two, and three dimensions. This code is documented in WCAP-7979-P-A.

FACTRAN is a radial pellet/clad temperature calculation model which is used to calculate the transient heat flux at the surface of a rod. This code is documented in WCAP-7908-P-A.

The licensee proposed to apply TWINKLE and FACTRAN to St. Lucie Unit 2 for analysis of the uncontrolled CEA withdrawal from a subcritical condition event and the CEA ejection event. The staff found that the TWINKLE and FACTRAN codes were previously approved by NRC for Westinghouse plants in calculating the neutron kinetics response of a reactor, and hot spot heat flux, respectively, for transients such as the uncontrolled CEA withdrawal from a subcritical condition and the CEA ejection event. Since (1) both codes are generic codes approved by the NRC, (2) the licensee applied both codes with the nuclear and fuel characteristics specific to the St. Lucie Unit 2 fuel for the two events (Reference 5), and (3) the licensee complied (Appendix B of Reference 5) with the SE restrictions (related to initial fuel temperatures, the gap heat transfer coefficient and number of concentric rings used for a fuel rod) imposed on the use of FACTRAN, the staff concludes that the application of the codes for the proposed use is acceptable.

3.3.4.5 PHOENIX-P and ANC

Both codes address three-dimensional features of the nuclear characteristics of the fuel. PHOENIX-P is used to generate the cycle-specific nuclear cross sections. ANC with the input from PHOENIX-P is used to calculate the nuclear characteristics such as power distributions, control rod worth, and reactivity feedback coefficients. As indicated in Reference 3, both PHOENIX-P and ANC (WCAP-11596-P-A) are currently used in AOR. Therefore, the licensee's application of the codes is acceptable.

The licensee also evaluated its compliance with the conditions specified in the SEs approving Westinghouse topical reports (discussed in Section 3.3 above) that were referenced in the licensee's non-LOCA analysis (Reference 5), and determined that the SE conditions imposed on use of the methodologies have been met (Appendix B of Reference 5). Accordingly, the staff concludes that the licensee adequately addressed the staff concern related to conformance to the SE conditions.

3.4 Transients and Accidents Analyses

The licensee evaluated the cases for each event category discussed in Chapter 15 of UFSAR, analyzed the limiting cases and presented the results of analyses in Reference 5. These analyses were performed at a rated core power of 2700 MWt with the following conditions (Reference 3):

1. Maximum SGTP of 30 percent in each of the two SGs.

2. Maximum tube plugging asymmetry of 7 percent between the two SGs.

3. A reduction in the minimum RCS flow specified in the TSs from 355,000 gpm to 335,000 gpm.

4. Cores containing the 16x16 CE HID-1L fuel with incorporation of the ZIRLO cladding material.

In response to RAI-8.b (Reference 7), the licensee listed the limiting single failures for each of the events analyzed and presented in Section 5 of Reference 5. Inclusion of any single failure which does not significantly increase the consequences of an event (e.g., failure of one protection train) relative to the event without a single failure, does not change the event category (i.e., moderate frequency to infrequent anticipated operational occurrence).

3.4.1 Delay Time of Loss-of-Offsite Power (LOOP) Credited in the Safety Analyses

3.4.1.1 Background

The licensee proposed to change from CE to Westinghouse methodologies for the non-LOCA analysis to support the proposed increase in SG tube plugging. The licensee proposed to take credit for the mechanistic time delay between the reactor trip, turbine trip and LOOP (due to grid instability). The licensee needs the delay time of LOOP to demonstrate acceptable margin for control room habitability.

St. Lucie Unit 2 currently assumes a LOOP coincident with the reactor trip for the SLB as the worst case. However, in the current AOR for the locked rotor analysis, the licensee used a mechanistic LOOP approach and determined that the LOOP delay time is 3.25 seconds following reactor trip (3 seconds following turbine trip). Since it previously credited this delay for the locked rotor analysis, the licensee proposed to also credit the LOOP delay time in the SLB analysis.

3.4.1.2 GDC and SRP Requirements

GDC 17 requires that a LOOP must be considered in the analysis of AOOs and accidents.

Implementation of the GDC requirements for the LOOP time is specified in the SRP guidance for three non-LOCAs: SLB, FLB and locked rotor events. In general, the guidance states that a licensee is requested to search for the worst time of LOOP (the conservative approach) but does not provide further specifics.

Specifically, the SRP states for SLB and FLB that:

> 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 accidents. 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 sequences of events for these accidents.

For the locked rotor event, the SRP states that:

> 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.

In implementing the above SRP guidance, the NRC has permitted licensees to use a mechanistic LOOP or a conservative LOOP approach for licensing applications. The staff decision to allow the mechanistic LOOP delay for the locked rotor event was made circa 1980 at the request of the industry to reduce the conservatism. However, licensees need to provide technical justification to gain NRC approval of the mechanistic LOOP approach.

The licensee also proposed to credit the LOOP time based on a mechanistic LOOP approach in the FLB analysis to be consistent with the LOOP time used the analysis of the locked rotor and SLB event. The evaluation of the LOOP time is discussed in Section 3.4.1.4 below.

3.4.1.3 Phenomena

The effect of the delay time of 3 seconds following the turbine trip before LOOP for a non-LOCA transient, such as SLB, is to increase DNBR margin. As shown in Table 5.1.5-1 of Reference 5, for an St. Lucie Unit 2 pre-trip SLB, the reactor trip signal is generated 0.4 seconds following the overpower-ΔT signal at 112.2 percent power level. The turbine trip occurs 0.25 seconds later. After another 0.49 seconds, control rod insertion begins. It takes about 2.66 seconds for the control rods to complete the insertion. If the LOOP is assumed simultaneously with the reactor trip (as assumed in the current AOR), the minimum DNBRs would occur at about the time of the LOOP when the reactor power is at its highest level and the RCS flow is at a reduced rate due to the loss of power to RCPs. The St. Lucie Unit 2 AOR shows that about 4 percent of the fuel would fail due to low DNBRs during an SLB. No fuel failure is calculated with the delay time credit.

The analysis performed with the Westinghouse methods for the St. Lucie Unit 2 plant assumes a LOOP to occur 3 seconds after the turbine trip. Since the LOOP is delayed for 3 seconds after the turbine trip, the control rods are inserted well into the core before the RCP coastdown (due to a loss of power to the RCPs resulting from a LOOP) begins. The resulting reactor power reduction compensates for the reduced flow encountered once power to the RCPs is lost. The analysis indicates that the minimum DNBRs are greater than the SAL DNBR limits, assuring that no fuel failure occurs. The minimum DNBRs predicted during the SLB occur prior to the time that flow coastdown begins. The results indicate that with the assumption of a LOOP at 3 seconds (or a longer delay time) after turbine trip, the LOOP will have no effect on the results of the SLB analysis in terms of the minimum DNBR calculation. Similar results are applicable to any event limited by DNBR, such as the locked rotor event.

3.4.1.4 Mechanistic LOOP Delay Time

The St. Lucie Unit 2 analysis of the SLB, FLB and locked rotor event presented in Reference 5 credited a LOOP delay time of 3 seconds following a turbine trip. The LOOP results in a loss of power to the RCPs which, in turn, reduces the RCS flow. This results in a lower DNBR and a higher RCS peak pressure. During the review, the staff requested the licensee to provide justification for the LOOP delay used in the analysis. In the response to RAI-8.d of Reference 7 and RAIs 1 and 8 of Reference 20, the licensee provided LOOP delay times based on the St. Lucie Unit 2 electrical design features and the grid stability analysis.

The response to RAI-8 of Reference 20 indicated that the LOOP would occur between 3 to 12 seconds following reactor/turbine trip or 9 seconds following a safety injection actuation signal (SIAS). The response to RAI-1 of Reference 20 indicated that a LOOP could occur at approximately 9 seconds following a SIAS with approximately 2 seconds of dead time before the SIAS loads begin to re-sequence onto the emergency diesel generators (EDGs). The response to RAI-1 of Reference 20 also indicated that the LOOP would occur at approximately 1 second following a SIAS with approximately 9 seconds of dead time before the SIAS components begin to re-sequence onto the EDGs. In the response to RAI-8.d of Reference 7 the licensee indicated that a one-half LOOP (half the safety loads and half the non-safety loads, including RCPs, lose offsite power) could occur approximately simultaneously with a reactor/turbine/generator trip.

Based on its review of the licensee's responses to various RAIs in References 7 and 20 addressing the LOOP time, the staff drew the following conclusions (See Section 5.0):

1. The LOOP occurring between 3 to 12 seconds following a reactor/turbine/generator trip with no SIAS at that time should be included in analyses of applicable events for licensing applications. The scenario is caused by the wide-scale grid breakup or voltage collapse event, which is unlikely to occur.

2. The LOOP occurring to the safety loads at approximately 9 seconds following a SIAS with approximately 2 seconds of dead time before re-sequencing on the EDGs is a likely LOOP scenario. This is the degraded-voltage, double-energization scenario.

3. The LOOP occurring to the safety loads at approximately 1 second following a SIAS with approximately 9 seconds of dead time before re-sequencing on the EDGS is not as likely as the item 2 scenario, but is still possible. This is a loss-of-voltage relay actuation scenario.

4. A one-half LOOP on the safety and/or non-safety loads (including RCPs) occurring approximately simultaneously with a reactor/turbine/generator trip with or without a SIAS occurring at that time, is a likely LOOP scenario. This is the failure of a fast-bus-transfer (FFBT) or the switchyard breaker-failure-protection spurious actuation scenario.

As indicated in item 1, for an event such as a wide-scale grid breakup, the LOOP could occur between 3 to 12 seconds following reactor/turbine trip. In the St. Lucie Unit 2 analysis, the licensee assumed the LOOP delay of 3 seconds following turbine trip, which is the shortest LOOP delay time that may occur for an unlikely event. The use of the short LOOP delay time results in a fast reduction of the core flow due to the RCP flow coastdown, thereby minimizing the heat removal rate that minimizes the calculated minimum DBNR and maximizes the peak RCS pressure. Therefore, the use of LOOP delay time of 3 seconds is conservative within the credible time of 3 to 12 seconds.

For various scenarios of the LOOP delay time discussed above, the staff requested the licensee to address the following two technical issues: the double-sequencing phenomenon during the SLB event and FFBT during the SLB, FLB and locked rotor event. As discussed in Sections 3.4.1.5.1 and 3.4.1.5.2 below, the staff has reviewed the licensee's responses and concluded that the licensee has adequately addressed the staff's concerns.

3.4.1.5 Technical Issues When LOOP Delay Time Is Credited

1. Double-Sequencing Phenomenon

For the SLB analysis taking credit for the LOOP delay time, the staff identified one technical issue that does not impact the locked rotor event. This is because SLB results in initiation of a SIAS due to the cooling and resulting shrinkage of the primary side inventory. Safety injection (SI) is, therefore, required during the SLB and not the locked rotor event.

During an SLB event, the released steam causes a decrease in the RCS temperature. In the presence of a negative MTC, the decreased RCS temperature results in a positive reactivity addition. After the reactor trip, if the resulting positive reactivity is greater than the negative reactivity from the inserted control rods and the borated water from the SI system, the core will return to criticality for an SLB post-trip core.

Since the actual time of a LOOP will vary, the staff requested the licensee to demonstrate that a LOOP at any time in excess of 3 seconds following turbine trip will not lead to insufficient borated water from the SI system that was credited in the proposed post-trip SLB analysis. This should account for the possibility that SI pumps may have started on normal ac sources and then lost power as the grid or main generator disconnected, until the EDGs start and loads (the double-sequencing phenomenon). The double-sequencing of the SI pumps will delay the time of injection of SI flow into the core and can cause a reduction in the borated water injected from the SI system.

In response to RAI-8 of Reference 20, the licensee indicated that in order to have a potential for double-sequencing, an SI must be initiated before the LOOP occurs. Based upon the most significant grid disturbance possible (initial reactor/turbine operation at full power) a maximum range for a potential LOOP could be from 3.0 to 12.0 seconds (discussed in item 1 of the Section 3.4.1.4 evaluation) following turbine trip. Therefore, for double-sequencing to occur, a SIAS signal must occur after turbine trip and before the 12-second maximum delay time for LOOP. This creates a very limited potential impact on the injected boron in the post-trip analysis of the SLB event. Assuming that a SIAS was generated on a high containment pressure signal within the first few seconds following the break, the SI pumps would be loaded on the buses. The SI in the analysis is assumed to begin with a delay of 30 seconds subsequent to the SIAS. If a LOOP were to occur in the time frame of 3 to 12 seconds following reactor trip, the SI pumps would have to be re-sequenced on to the EDGs, which would have started on the SIAS. In the scenario of LOOP at 12 seconds, the effect of the borated water delivered to the core would be minimally affected. The effect of the borated water for scenarios where LOOP occurs at 1 second (discussed in item 3 of Section 3.4.1.4) or 9 seconds (discussed in item 2 of Section 3.4.1.4) following SIAS, would also be minimally affected because of the short period of time without the SI flow delivered to the core due to the double-sequencing phenomenon.

The licensee performed sensitivity calculations to determine the impact on the post-trip SLB analysis. To delay safety injection, the analysis conservatively did not take credit for the SIAS on high containment pressure and only the low pressurizer pressure signal is used to initiate safety injection. Three HZP SLB cases were analyzed with each case assuming that a LOOP occurred at 0 seconds, 3 seconds and 12 seconds following break initiation and reactor trip, which were assumed to open simultaneously at the initiation of the event. The results show that the effect of a difference in the timing of the LOOP and the initiation of SI has essentially a negligible effect on the limiting point in the transient. Specifically, a variation in the time of SI initiation on the order of 4 seconds has approximately a 1-to-2 ppm effect on the boron in the core at the time of peak heat flux. Therefore, the delay in the timing of LOOP, as mentioned above, is not expected to adversely affect the results, as the boron concentration changes minimally. Also, the licensee's analysis demonstrated that the LOOP case is non-limiting compared to the post-trip SLB case with offsite power available. Therefore, the staff concludes that effects of the double-sequencing on the SLB analysis are satisfactorily addressed.

2. Failure of one Fast Bus Transfer

In support of the LOOP delay time of 3 seconds following turbine trip used in the licensing calculations, the licensee analyzed the potential for LOOP scenarios on the non-safety 6.9kv RCP buses. The licensee concluded that the immediate loss of one 6.9 KV 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 (such as FFBT, which is discussed in item 4 of Section 3.4.1.4). The licensing report used to support the 30 percent SGTP application credited the LOOP delay time of 3 seconds in the SLB, FLB and locked rotor analyses. Therefore, the staff requested the licensee to address the effect of the immediate loss of two RCPs due to an FFBT on the results of the analyses for SLB, FLB and locked rotor events and provide the limiting case for the staff to review.

In response to the staff's request, the licensee performed the SLB and FLB analyses with an FFBT and presented the results in the response to RAI-5 of Reference 20 for the SLB analysis and in the response to RAI-6a of Reference 8 and RAI-3 of Reference 20 for the FLB analysis. The staff has reviewed the analyses and concluded that the effects of the FFBT are appropriately addressed in the applicable analyses. The staff evaluation in Sections 3.4.2.4 and 3.4.2.5 for the SLB analysis and Section 3.4.2.10 for the FLB analysis concluded that the analyses are acceptable. The licensee performed the locked rotor event with the FFBT (RAI-10 of Reference 20). The staff evaluation in Section 3.4.2.12 concluded that the analysis is acceptable.

The licensee indicated that the current AOR for the locked rotor event credited the LOOP delay time of 3 seconds, and claimed that its use of the LOOP delay time for SLB and FLB analyses need not address FFBT in the analysis of the locked rotor event. The staff did not agree with the licensee's position. The NRC acceptance of the LOOP delay time in the locked rotor analysis was based on the licensee's grid stability analysis and St. Lucie Unit 2 electrical design features, which demonstrated that the minimum LOOP delay time could not be less than 3 seconds following turbine trip. The FFBT was analyzed for this proposed amendment based on St. Lucie Unit 2 electrical design features that were not considered in the licensee's grid stability analysis that previously determined the delay time of 3 seconds. This failure, therefore, should be considered in the safety analysis that credited the LOOP delay time, and the staff requested the licensee to address the effect of FFBT on the analyses of the SLB and FLB events, as well the locked rotor event.

3.4.2 Non-LOCA Transients Analyses

The staff's review of the non-LOCA analyses is discussed in the following sections:

3.4.2.1 Increase in Feedwater Flow

An increase in feedwater flow event may be caused by system malfunctions or operator actions that result in an inadvertent opening of a feedwater control valve. The excessive feedwater flow reduces reactor coolant temperature, which, in turn, causes a power increase because of the effects of the negative MTC of reactivity. The reactor trip initiated by high power, low pressurizer pressure, thermal margin/low pressure, or low SG pressure signals provides protection against undesirable conditions.

The licensee performed the analysis using RETRAN for RCS response calculations and VIPRE for DNBR calculations. The analysis consists of both the full-power and hot zero-power cases. In the DNBR calculations, the initial reactor power, RCS pressure and temperature are assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A. The licensee assumed that the increase in feedwater flow event is caused by opening of the feedwater control valves to maximum capacity, resulting in a step increase to 120 percent of the nominal full-power feedwater flow to both SGs. The feedwater temperatures are assumed to be 435 ^{0}F and 240 ^{0}F, corresponding to normal plant conditions for the full-power and zero-power cases, respectively. Maximum reactivity feedback conditions with a minimum Doppler-only power defect is assumed, thereby, maximizing the power increase. The feedwater flow resulting from a fully open control valve is terminated by the SG high-high water level signal or operator action.

The licensee performed the analysis using an acceptable method, and the results of the analysis demonstrate that the consequences of this event meet the acceptance criteria of SRP 15.1.2. Specifically, the calculated minimum DNBR is above the SAL DNBRs. Therefore, the staff concludes that the analysis is acceptable.

3.4.2.2 Inadvertent Opening of a SG Safety Valve/Atmospheric Dump Valve

An inadvertent opening of an SG safety valve or atmospheric dump valve (ADV), a moderate-frequency event, may result in an increase in steam flow. In the presence of a negative MTC, the excessive cooldown by the increased steam flow increases positive reactivity which, in turn, increases the core power level. As a result of the power increase and RCS pressure decrease, the calculated DNBRs may decrease, possibly causing fuel damage.

Since the steam flow from either the SG safety valve or ADV is within the range of steam flow from various sizes of the SLB, the consequences of cooldown effects from the inadvertent opening of SG safety valve or ADV are bounded by that of the SLB. As discussed in Sections 5.1.5 and 5.1.6 of Reference 5, the SLB analysis shows no DNBR below the SAL DNBRs, thus meeting the acceptance criteria of SRP for the moderate-frequency events. Therefore, the staff concludes that the results of an inadvertent opening of SG safety valve or ADV, a less limiting event than the SLB event, will meet the SRP acceptance criteria for the moderate-frequency events, and are acceptable.

3.4.2.3 Decrease in Feedwater Temperature

A decrease in feedwater temperature event, a moderate-frequency event, may be caused by failure of a low- or high-pressure feedwater heater train. A decrease in feedwater temperature decreases reactor coolant temperature, which, in turn, causes an increase in core power because of the effects of the negative MTC of reactivity. Since the rate of energy change is reduced as load and feedwater flow decrease, the transient initiated from zero-power conditions is less severe than the full-power case. The licensee's analysis for the limiting case is based on the initial full-power conditions with a decrease in feedwater temperature in both SGs caused by a loss of one string of high-pressure heaters. The loss of a string of feedwater heaters results in a maximum reduced feedwater temperature of 335 ^{0}F. The analysis assumes that the nominal full-power feedwater flow is maintained in both SGs. The reactor trip from high power, low pressurizer pressure, thermal margin/low pressure, or low SG pressure signals provides reactor core protection. The high-high SG level trip signal prevents the continuous addition of feedwater flow at a reduced temperature by closing the main feedwater pump discharge valves, tripping the turbine, and stopping the main feedwater pumps.

The licensee performed the analysis using acceptable methods: RETRAN for RCS response calculations and VIPRE for DNBR calculations. The results of the analysis show that the calculated minimum DNBR is above the SAL DNBRs, thus meeting the acceptance criteria of SRP Section 15.1.2 with respect to the fuel integrity. Therefore, the staff concludes that the analysis is acceptable.

3.4.2.4 Pre-Trip Main Steam Line Break

Section 5.1.5 of Reference 5 describes the revised pre-trip SLB event analysis supporting the 30 percent SG tube plugging limit. This analysis is supplemented by responses to staff RAIs in References 7, 8, and 20.

The new SLB analysis is a significant departure from the current (AOR) documented in UFSAR 15.1.4.3.5.1. The changes in methodology have a significantly greater effect in the analysis than the increase in SG tube plugging. Major deviations from the UFSAR AOR are listed below:

1. Migration to latest Westinghouse computer models (e.g. ANC, RETRAN, VIPRE).

2. Assumption for timing of LOOP.

3. No credit for the High Containment Pressure Reactor Trip (HCPT) function.

4. Assumed single failure.

RETRAN has previously been reviewed and approved for modeling (1) excessive increase in steam flow and (2) SLB transient events in Westinghouse-designed 4-, 3-, and 2-loop plants (Reference 17). A comparison of SG specification and operating characteristics for St. Lucie Unit 2 along with Westinghouse-designed SGs is provided in Attachment 5 of Reference 7. Based upon a review of this data, the staff concludes that the St. Lucie Unit 2 SG design and operating characteristics are within the range of Westinghouse SG designs. Further, RETRAN has been approved to model the LOOP and loss of forced reactor coolant flow transient events (Reference 17). Based upon the previous review and approval of RETRAN for a wide spectrum of transients and the similarities in the nuclear steam supply system (NSSS) design of St. Lucie Unit 2 and Westinghouse PWRs, the staff finds the use of RETRAN to model the SLB break spectrum with and without a LOOP acceptable.

During the review, the staff requested additional information on certain aspects of the pre-trip SLB analysis - specifically, credited reactor trip functions, temperature decalibration effects on excore signals, local power peaking factors, and accounting for instrument uncertainties. In response to RAI-13 of Reference 7, the licensee provided an adequate response to these inquiries.

The St. Lucie Unit 2 UFSAR Section 15.1.4.3 provides details from the Cycle 1 "limiting fuel performance event" - pre-trip SLB with FFBT. In this analysis, failure to achieve a fast transfer of a 6.9 kV bus is assumed to occur coincident with turbine trip, causing two RCPs to coastdown. This Cycle 1 analysis resulted in 3.7 percent fuel failure due to DNB. Subsequent to Cycle 1, the St. Lucie Unit 2 UFSAR Section 15.1.4.3.5.1 lists the limiting scenario as inside containment (IC) SLB with LOOP. The UFSAR states that the LOOP is assumed to occur concurrent with the RPS system trip breakers opening (RTBO). This assumption on LOOP timing is consistent with that employed for other CE plants and bounds scenarios that include a LOOP concurrent with break and the case without a LOOP. The pre-trip IC SLB with LOOP results in less than 33-percent fuel failure due to DNB.

As part of the 30-percent SG tube plugging amendment (Reference 5), the licensee has justified a 3-second delay between the turbine trip and a LOOP due to grid collapse. Section 3.4.1.4 of this safety evaluation addresses the acceptability of this assumption. Note that even though the mechanistic, delayed LOOP does not impact the amount of DNB degradation experienced during the SLB event, a LOOP after turbine trip will impact offsite dose calculations (e.g., controlled steam release to atmosphere during plant cooldown) and, thus, must be included.

The revised pre-trip SLB analysis (Reference 5) includes a LOOP 3.25 seconds after RTBO (3.0 seconds after turbine trip which is delayed 0.25 seconds). With regard to peak linear heat generation rate and approach to fuel melting, the revised SLB analysis (with full RCS flow) represents the limiting case. However, with respect to DNB degradation, the staff had concerns that the revised SLB scenario, which effectively removed any detrimental effects of RCP coastdown on the fuel performance, may not bound either (1) SLB with a coincident LOOP or (2) SLB with FFBT.

In response to an RAI regarding the SLB with coincident LOOP event (RAI-4a, Reference 8), the licensee stated that the DNB degradation experienced would be similar to that in the complete loss of flow (LOF) analysis. This conclusion would not be valid if the low RCS flow trip function was impacted by a potential harsh containment environment which is experienced during an IC SLB. In response to a related RAI regarding the environment qualification (EQ) status of the low RCS flow instrumentation (RAI-4e, Reference 8), the licensee stated that given the location of the instruments and the short duration that the function would be required to be operable, the low RCS flow trip function would provide the necessary response and no harsh environment effects are required. Due to concerns that containment environment may rapidly degrade during an IC SLB, the staff would not accept the licensee’s position that the instruments need not consider harsh environment effects.

In response to a subsequent RAI (RAI-6, Reference 20), the licensee demonstrated the EQ status of the low RCS flow instrumentation and quantified the harsh environment uncertainty. A new harsh environment analytical setpoint of 87.9 percent was documented, which is 4 percent lower than the normal low RCS flow analytical setpoint.

In response to RAI-5 of Reference 20, the licensee provided details of the pre-trip SLB with coincident LOOP analysis. The sequence of events is presented in Table B of this RAI response. Accounting for harsh environment conditions has delayed the reactor trip function and yielded a limited number of failed fuel rods. Based upon St. Lucie Unit 2's current licensing basis, a limited number of fuel failures is acceptable provided doses do not exceed 10 CFR Part 100 guidelines. In response to RAI-10 of Reference 20, the licensee described the methodology for calculating the number of fuel rods in DNB. Based upon review of these RAI responses, the staff finds the deterministic methods for calculating the number of failed fuel rods and the overall pre-trip SLB with coincident LOOP analysis acceptable.

In response to an RAI regarding the pre-trip SLB with FFBT event (RAI-4b, Reference 8), the licensee provided a summary of a case that was evaluated. The staff had further questions concerning the sequence of events and modeling techniques employed in this case. In response to a subsequent RAI (RAI-5 of Reference 20), the licensee provided details of the transient analysis. The pre-trip SLB with FFBT analysis was modeled as a composite event with the two-pump flow coastdown superimposed on the peak power excursion transient. No credit was taken for any reduction in core power (during the flow coastdown heatup portion of the event) that would be experienced with the reactivity feedback parameters selected to maximize power (during the SLB cooldown portion of the event).

A review of the initial conditions and input parameters identified one potentially nonconservative assumption. The sequence of events table lists the FFBT occurring coincident with the main turbine trip, but 0.25 delayed from RTBO. While a physical delay may exist between these signals, no surveillance requirements are performed. As such, the staff does not accept credit for any delay between RTBO, turbine trip, and FFBT (which promotes a more benign transient). Based upon the conservative nature of the composite event, which compensates for the 0.25 second delay in FFBT, the staff finds the pre-trip SLB with FFBT analysis presented in this RAI response acceptable.

In response to an RAI regarding the validity of the thermal-hydraulics modeling of inlet flow distribution and cross-flow characteristics during a two-pump coastdown (RAI-9, Reference 20), the licensee stated that "Westinghouse is also not aware of any 2-out-of-4 pump coastdown test data that are applicable to a pre-trip steam line break . . . ." Further, the licensee stated that the impact of a two-pump coastdown on local flow characteristics is offset by conservative assumptions and modeling techniques in the safety analysis methodology. In response to this RAI, the following conservatisms have been identified which may be credited to offset any potential impact of the two-pump local flow characteristics:

1. In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the two-pump coastdown.

2. In RETRAN, the transient nuclear power prediction assumes a minimum scram reactivity worth based upon the most bottom-peaked axial power distribution. In VIPRE, the DNBR calculations are based on a top-peaked axial power distribution.

3. In VIPRE, the peak power assembly with the peak rod at the radial peaking factor (Fr) design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

4. In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate Fr corresponding to the DNB specified acceptable fuel design limits (SAFDL). By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

In combination with the composite transient (which superimposes the two-pump coastdown flow on the peak power excursion SLB case), items 1, 2, and 3 above compensate for any nonconservative aspects of the thermal-hydraulics model relative to the two-pump coastdown inlet flow distribution and cross-flow characteristics. These conservative modeling assumptions ensure that the minimum DNBR calculations remain conservative. If the calculated minimum DNBR was below the SAFDL, item 4 could have been credited to ensure that the predicted number of failed fuel rods remain conservative.

According to the St. Lucie Unit 2 UFSAR Section 15.1.4.3.5.1, the pre-trip SLB is analyzed to ensure that a coolable geometry is maintained and that site boundary doses do not exceed 10 CFR Part 100 guidelines. Coolable geometry is maintained by satisfying DNB propagation criteria and by demonstrating that incipient fuel melting does not occur. Site boundary doses are maintained within acceptable limits by demonstrating that the amount of fuel rod failures (due to DNB) do not exceed the assumption in the docketed dose calculation. Because the radial and axial peaking factors are dependent on the cycle-specific loading pattern, the minimum DNBR, number of failed rods in DNB, and peak LHR are verified during each reload design. Based upon the above review, the staff concludes that the results of the three limiting pre-trip SLB cases (pre-trip SLB with no single failure, pre-Trip SLB with coincident LOOP, and pre-trip SLB with FFBT) are acceptable.

3.4.2.5 Post-Trip Main Steam Line Break

Section 5.1.6 of Reference 5 describes the revised post-trip return-to-power (RTP) SLB event supporting the 30-percent SG tube plugging limit. This analysis is supplemented by responses to staff RAIs in References 7 and 20.

The new RTP SLB analysis is a significant departure from the current AOR documented in UFSAR Section 15.1.4.3.5.2. The changes in methodology have a significantly greater effect in the analysis than the increase in SG tube plugging. Major deviations from the UFSAR AOR are listed below:

1. Migration to latest Westinghouse computer models (e.g., ANC, RETRAN, VIPRE).

2. Designation of a single limiting case: HZP SLB with offsite power available.

3. Removal of HERMITE void reactivity credit.

4. Additional delay in isolating feedwater to the faulted SG.

5. Modeling of local flow and cross flow in the LOOP cases.

A discussion on the acceptability of RETRAN to model the St. Lucie Unit 2 SLB event is provided in the pre-trip SLB section, Section 3.4.2.4 of this safety evaluation.

During the review, the staff requested additional information on certain aspects of the post-trip RTP SLB analysis. Specifically, the selection of limiting single active failure, initial conditions, SG blowdown flow rate, delayed neutron fraction, inverse boron worth, power peaking factors, and SIAS analytical setpoints. In response to RAI-14 of Reference 7, the licensee provided an adequate response to these inquiries.

The revised HZP SLB RTP case presented in Reference 5 assumes nominal 100-percent power main feedwater flow into the faulted SG until feedwater isolation. The staff had concerns that the rapid depressurization of the SG may draw feedwater at a rate even higher than normal delivery. In response to an RAI (Attachment 9 to Reference 7), the licensee provided a discussion of the feedwater flow sensitivity on the results. In this response, credit is taken for the 90-second delay assumed for feedwater isolation to the faulted loop. This delay results in isolation of feedwater at 92.9 seconds into the transient as compared to an isolation that may have occurred at 8.51 seconds (based upon TS requirements of 5.15-second isolation following a low SG pressure (LSGP) signal). In the RAI response, the delay in feedwater isolation relative to the TS requirement results in approximately 138,000 lbm of additional feedwater delivery prior to isolation. Since the cooldown and associated nuclear power rise during the transient is terminated by dryout of the faulted SG, the significant delay in SG dryout resulting from the delay in feedwater isolation (92.9 versus 8.51 seconds) promotes a conservative transient response. Based upon this extended delay in feedwater isolation, the staff finds the feedwater model and the overall transient response of the revised HZP SLB RTP case presented in Reference 5 conservative.

The St. Lucie Unit 2 UFSAR Section 15.1.4.3 provides details of four post-trip RTP SLB cases: (1) HZP with offsite power available, (2) hot full power (HFP) with offsite power available, (3) HZP with LOOP, and (4) HFP with LOOP. In its proposed amendment request (Reference 5), the licensee states that the HZP SLB with offsite power available bounds the remaining three scenarios and presents details from only this limiting case.

The staff had concerns that the SLB with LOOP events may challenge the DNBR SAFDL as had been indicated in previous St. Lucie Unit 2 analyses. In response to RAI-14a (Reference 7), the licensee provides additional justification supporting the judgment that the LOOP events are bounded by events without a LOOP. Several overly conservative modeling techniques are identified in the current UFSAR SLB with LOOP analyses including an artificial 40-percent flow (used to compensate for cross flows not accounted for in the closed channel model). In its response (Attachment 8 of Reference 7), the licensee stated that specific SLB with LOOP analyses were performed using NRC-approved neutronic and core thermal-hydraulic codes and methods. The conclusions of these analyses confirm that the LOOP cases were nonlimiting. Furthermore, the licensee presented sensitivity cases on core flow and assembly cross flow (Attachment 3A of Reference 7) that demonstrate, for a variety of local flow conditions, that the minimum DNBR experienced during a realistically modeled low flow condition (consistent with a LOOP case) remains above the minimum DNBR for the full-flow SLB case. Based upon the information presented in the St. Lucie Unit 2 proposed amendment request and in response to RAIs, the staff agrees that post-trip RTP SLB cases without a LOOP are limiting with respect to peak local power and minimum DNBR criteria.

As part of the proposed amendment (Reference 5), the licensing basis of the timing of the LOOP was altered. Since the point of interest in the post-trip SLB scenario occurs significantly after the reactor trip (at the approach to criticality), a LOOP at 3 seconds post-trip or following SIAS has little impact on this event. However, the staff had concerns that a LOOP (and RCP coastdown) near the peak RTP may promote worst consequences. Based upon the new licensing basis concerning degraded voltage and the timing of a LOOP, a LOOP near the peak RTP will occur well beyond the 3 to 12 second window and will not be addressed in this report.

The St. Lucie Unit 2 UFSAR Section 15.1.4.3.5.2 presented the details from both HZP and HFP initial conditions. The staff had concerns that the HFP SLB with offsite power available may challenge DNBR and linear heat generation rate SAFDLs as had been indicated in previous St. Lucie Unit 2 analyses. In response to RAI-7 of Reference 20, the licensee presented an SLB case initiated from HFP conditions. Conservative inputs and initial conditions were selected including the minimum shutdown margin preserved in the TSs. The RAI response also describes the process for validating the TS shutdown margin for future reload designs. The results of this case were compared against the UFSAR HFP SLB case. In both cases, the post-trip core reactivity is maintained sub-critical (approximately -0.6 percent$\Delta\rho$ in both cases). Whereas, the HZP SLB case presented in the licensing amendment achieves core post-trip re-criticality and a significant RTP. Based upon these results, the staff finds that the conservatively modeled HZP SLB case is more limiting than the HFP SLB case.

The sequence of events for the limiting post-trip SLB case - HZP SLB with offsite power available - is presented in Table 5.1.6-1 of Reference 5. As stated in an RAI response (Attachment 8 of Reference 7), the SLB is a Condition IV event which must satisfy the dose limit requirements. However, the licensee has conservatively analyzed this event to satisfy Condition II event criteria which preclude fuel damage. The limiting post-trip SLB case presented demonstrates that DNBR and peak LHR limits are not exceeded. Future reloads will need to ensure, based upon cycle-specific core physics predictions, that these limits are not exceeded. Based upon the above review, the staff finds the results of the post-trip SLB event acceptable.

3.4.2.6 Decreased Heat Removal by the Secondary System

The events with a decrease in heat removal by the secondary system include (1) turbine trip, (2) loss of normal feedwater flow (LONF), (3) LOOP, (4) loss of condenser vacuum (LOCV), (5) asymmetric SG transients (ASGTs), and (6) FLB. These events are characterized by a rapid reduction in heat removal capability of SGs. The loss of heat removal capability results in a rapid rise in the SG's secondary system pressure and temperature, and a subsequent increase in the RCS primary system pressure and temperature. Reactor trip and actuation of secondary and primary safety valves mitigate the effects of the primary-to-secondary system power mismatch during these events. The severity of these events is increased if the primary-to-secondary system power mismatch is increased. The licensee analyzed Event-4, LOCV, with initial conditions to bound Event-1, turbine trip, and provided the results of analysis in Section 5.1.10 of Reference 5. The licensee did not analyze Event-2, LONF, and Event-3, LOOP, and provided its rationale in Section 5.1.9 of Reference 5 and the response to RAI-15.a of Reference 7 for these two unanalyzed events that are bounded by other moderate-frequency events. The licensee analyzed Event-5, ASGT, and Event-6, FLB, and provided the results of analyses in Sections 5.1.11 and 5.1.12 of Reference 5, respectively.

3.4.2.7 Turbine Trip and Loss of Condenser Vacuum

Signals such as generator trip, low condenser vacuum, manual trip and reactor trip may initiate the turbine trip event. Following a turbine trip, the turbine stop valves rapidly close, and steam flow to the turbine abruptly stops. The loss of steam flow results in a rapid increase in secondary system pressure, and temperature, as well as a reduction of the heat transfer rate in the SGs, which, in turn, causes the RCS primary system pressure and temperature to rise.

LOCV may result in a turbine trip and prevent steam from dumping to the condenser. The licensee analyzed this event as a turbine trip from full power with a simultaneous loss of feedwater to both SGs due to low suction pressure on the feedwater pumps. In addition, the licensee assumed that the ADVs and the steam dump and bypass system valves were unavailable, which minimizes the amount of cooling and maximizes the RCS and secondary peak pressure. Because the licensee assumed that steam dump and feedwater flow are unavailable in the LOCV analysis, no additional adverse effects will result for the turbine trip event caused by the LOCV. Therefore, the LOCV analysis bounds the turbine trip event. The reactor trip signals of high pressurizer pressure or thermal margin/low pressure (TM/LP) provide protection against undesirable conditions during the LOCV event.

The licensee performed the analysis of the LOCV event using RETRAN for the transient response calculation and VIPRE for the DNBR calculation. The licensee analyzed three cases for the LOCV event. One case calculated the minimum DNBRs. The other two cases calculated the peak RCS primary and secondary pressures, respectively. A maximum of 30 percent of the SG U-tubes were assumed to be plugged. For the case analyzed to show that the SAL DNBRs were not exceeded, automatic pressurizer control was modeled and safety valves were modeled assuming a -3 percent setpoint tolerance, consistent with the St. Lucie Unit 2 TS. The pressurizer pressure control will actuate the pressurizer spray that causes the pressurizer pressure to decrease, and the lower safety valve setpoint will open the safety valves at a lower pressure and limit the pressure increase. The combined effects result in a lower RCS pressure, which, in turn, results in lower DNBRs. In the DNBR calculations, the initial reactor power, RCS pressure and temperature were assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A.

For the cases analyzed to show that the peak pressure was within 110 percent of the design pressure, initial core power and reactor coolant temperature were assumed at the maximum values for full-power operation with inclusion of the associated measurement and calibration uncertainties. Initial pressurizer pressure was assumed at the minimum value corresponding to full-power operation. The minimum pressurizer pressure will delay reactor trip on high pressurizer pressure and result in a higher peak pressure. In addition, for the RCS primary system pressurization case, no credit was taken for the effect of the pressurizer spray or power operated relief valves (PORVs) in reducing the primary RCS pressure. Pressurizer safety valves (PSVs) were modeled assuming a 3 percent setpoint tolerance (consistent with St. Lucie Unit 2 TSs) to open the safety valves at a higher pressure. For the SG shell side pressurization case, credit was taken for the effect of the pressurizer spray in reducing the primary pressure, thus, delaying the actuation of the reactor trip signal. Delaying the reactor trip increases the energy input to the secondary system, and results in a higher secondary system pressure. Consistent with TS 3/4.4.4 (RAI-16.a of Reference 7), one of the two PORVs was assumed to open on the high pressure trip signal. For all cases analyzed, no credit was taken for auxiliary feedwater (AFW) flow since stabilized plant conditions would be reached before AFW initiation was normally assumed to occur for full-power cases.

The staff finds that (1) the analysis uses acceptable methods and adequate assumptions to maximize the peak pressure or minimize the lowest DNBR, (2) the calculated RCS primary and secondary system pressures are within 110 percent of the design pressure, and (3) the calculated minimum DNBR is within the SAL DNBRs. Therefore, the staff concludes that the LOCV analysis meets the acceptance criteria of SRP 15.2.3, and the analysis is acceptable.

3.4.2.8 Loss of Normal Feedwater and Loss-of-Offsite Power

A LONF flow event may be caused by feedwater pump failures, valve malfunction, or loss of ac power sources. Following a LONF, the SG water inventory decreases as a consequence of continuous steam supply to turbine. The mismatch between the steam flow to the turbine and the feedwater leads to the reactor trip on a low SG level signal. Following reactor trip, the rate of heat generation in the RCS may exceed the heat removal capability of the SGs. The power generation and heat removal mismatch will result in an increase in the SG pressure, and an increase in RCS pressure, temperature and pressurizer water level.

A LOOP event may be caused by a complete loss of the offsite grid, accompanied by a turbine-generator trip. This event is identical to the LONF event except that a loss of power to the RCPs occurs simultaneously with the LONF.

The licensee indicated that with respect to a decrease in DNBRs, the LONF and LOOP events are bounded (Attachment 2 to Enclosure 3 of Reference 7) by the complete LOF event discussed in Section 5.1.14 of Reference 5. For the LONF event, the RCS temperature increases slightly before reactor trip, while no appreciable power increase occurs and the full RCS flow remains available. The effect of the reduction in RCS flow on the DNBR for the complete LOF event is more significant than the effect of increase in the RCS temperature for the LONF event before reactor trip. After the reactor trip, the power and RCS temperature decrease while the full RCS flow remains available, the DNBR will increase significantly during the LONF. As for the LOOP event, the RCPs will coast down immediately in addition to the loss of feedwater flow. This event is identical to the LOF event except that the reduction in feedwater flow will reduce the cooling of the RCS primary system, which, in turn, results in an increased RCS pressure, thereby increasing the DNBR in comparison to the LOF analysis. The increased SG primary side exit temperature will not have sufficient time to reach the core inlet to adversely affect the DNBR calculation. Therefore, the minimum DNBR for the LOOP event is bounded by that of the LOF event.

With respect to over pressurization, the LOCV event discussed in Section 5.1.10 of Reference 5 will bound either the LONF or LOOP event because the LOCV event causes a turbine trip with the LONF. The net effect of the turbine trip and LONF for the LOCV event is a total loss of RCS secondary system heat sink, which results in the greatest challenge to RCS primary and secondary system pressurization. Therefore, the LOCV event remains to be the limiting event in terms of the peak RCS primary and secondary system pressures.

Based on the above discussion, the staff agrees with the licensee that the consequences of the LONF and LOOP events are bounded by the analyses of the LOCV and LOF events, which are found acceptable (as discussed in Sections 3.4.2.7 and 3.4.2.11 of this evaluation, respectively). Therefore, the staff concludes that the consequences of the LONF and LOOP events are acceptable.

3.4.2.9 Asymmetric SG Transients

The ASGTs, which affect a single SG, are loss of load to one SG, excess load to one SG, loss of feedwater to one SG and excess feedwater to one SG. In support of the operation with the SGTP level of 30 percent, the licensee analyzed the loss of load to one SG from a full-power condition, which is the limiting ASGT identified in the UFSAR. The licensee modeled this event as an inadvertent closure of the main steam line isolation valve of one SG. During the transient, its pressure and temperature increase to the opening pressure of the main steam safety valves (MSSVs). As a result of the steam relieved through the MSSVs, the pressure in the affected SG decreases and stabilizes at the MSSV setpoint pressure. The unaffected SG continues to supply steam to the turbine. The steam flow from the unaffected SG results in an overcooling of the cold legs associated with the unaffected loop. The increase in the core inlet temperature from the affected loops in combination with the decrease in core inlet temperature from the unaffected loops results in a large core temperature asymmetry. The asymmetric core temperature distributions result in an increase in the radial and axial peaking in the core, causing a challenge to the design DNBR safety limit. The high SG differential pressure reactor trip serves as the primary means of mitigating this event.

The licensee analyzed this event using RETRAN to calculate the core average heat flux, core pressure and core inlet temperature. The core radial and axial peaking factors are determined using the thermal-hydraulic condition from the transient analysis as input to the ANC nuclear core models. VIPRE is used to calculate the heat flux and DNBR transients based on the nuclear power and core temperature and pressure from RETRAN. In the DNBR calculations, the initial reactor power and temperature are assumed to be at their nominal values, the initial RCS flow is assumed to be at a value consistent with the minimum measured value and the initial RCS pressure is assumed to be at a value consistent with minimum value allowed by the plant TSs. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP documented in WCAP-11397-P-A. The analysis assumes reactivity feedback coefficients that maximize the increase in nuclear power prior to reactor trip. The coolant channels of the core associated with the unaffected loop (which continues to provide steam flow to the turbine, and thus increases cooling of the RCS primary system) are treated (see the response to RAI-17.b discussed in Reference 7) as being more important to the determination of core power (80 percent weighting) than the core channels associated with the affected loop (20 percent weighting). The licensee analyzed two cases: one with zero-percent level of SGTP and one with 30-percent level of SGTP. The results show that the calculated minimum DNBR of 1.77 for the limiting case - the 30 percent level SGTP case - is significantly greater than the SAL DNBRs.

The staff finds that the analysis uses acceptable methods and reasonable assumptions. The results of the analysis for the limiting case show that the minimum DNBR remains significantly above the SAL DNBRs, satisfying the acceptance criteria of the SRP Section 15 for moderate-frequency events. Therefore, the staff concludes that the analysis is acceptable.

3.4.2.10 Feedwater Line Break

Section 5.1.12 of the St. Lucie Unit 2 licensing amendment (Reference 5) describes the revised FLB event supporting the 30 percent SGTP limit. This analysis is supplemented by responses to staff RAIs in References 7, 8, and 20.

The new FLB analysis is a significant departure from the current AOR documented in UFSAR Section 15.2.1.1. The changes in methodology have a significantly greater effect in the analysis than the increase in SG tube plugging. Major deviations from the UFSAR AOR are listed below:

1. Migration to latest Westinghouse computer models (e.g., RETRAN).

2. Modeling of break flow rate and enthalpy.

3. Assumption for timing of LOOP.

4. Combining the small FLB event and large FLB with LOOP event into one event classification with a single set of acceptance criteria. (See additional discussion below.)

5. Worst single active failure.

In response to RAI-18 of Reference 7, the licensee provided further details on the RETRAN methodology and FLB modeling techniques, including differences between the new analysis and the UFSAR AOR. The Westinghouse methodology used for St. Lucie Unit 2 has been applied to Westinghouse-designed plants for many years. Further, the use of RETRAN to model FLB transients has been reviewed and approved by the staff (Reference 17).

Due to the simplicity of the secondary side model, the UFSAR FLB employed very conservative modeling techniques. For example, the elevation of the main feed ring was lowered toward the tube sheet in order to achieve a completely liquid discharge. The FLB analysis performed with the Westinghouse methodology maintains the actual feed ring elevation and allows RETRAN to calculate break flow and enthalpy. This methodology change has a significant impact on the NSSS response into a FLB event. In this new analysis, the event turns from a decreased heat removal (heatup) event to an excess heat removal (cooldown) event as the blowdown quality approaches 1.0.

The staff had concerns that the realistic modeling of the feed ring in RETRAN may yield nonconservative peak pressure calculations. In response to RAI-18.a of Reference 7, the licensee provided details on the past use of RETRAN and NOTRUMP to predict the SG transient behavior during an FLB event for Westinghouse-designed plants. Westinghouse reviewed the SG design and determined that the SG modeling in RETRAN (Reference 17) was appropriate for St. Lucie Unit 2 and required no renodalization. A comparison of SG specification and operating characteristics for St. Lucie Unit 2 along with Westinghouse-designed SGs is provided in Attachment 5 of Reference 7. Based upon a review of this data, the staff concurs that the St. Lucie Unit 2 SG design and operating characteristics are within the range of Westinghouse SG designs already employing the Westinghouse FLB methodology. Therefore, application of RETRAN to the St. Lucie Unit 2 SG design is acceptable.

As stated in response to RAI-18.a, Westinghouse methodology does not require specific analysis of DNB and RCS over pressurization analyses since these criteria would be bounded by analyses of other events. This conclusion requires the viability of the low SG level (LSGL) reactor trip. While the NOTRUMP model in the RETRAN code has been employed in the past to model the dynamic behavior of Westinghouse designed SGs and predict indicated SG water level, this would be the first application to a CE-designed SG. The staff had concerns that the complex, dynamic phenomena affecting indicated SG downcomer water level would be difficult to predict with a high degree of accuracy. After reviewing the response to RAI-18, including the NOTRUMP nodalization provided in Attachment 4A of Reference 20, the staff remains unable to accept credit for the RPS LSGL reactor trip function for St. Lucie Unit 2 based upon either NOTRUMP or RETRAN SG water level predictions.

The new St. Lucie Unit 2 RETRAN FLB analysis credits the high pressurizer pressure (HPP) and LSGP reactor trip functions along with appropriate delays and affects of a harsh containment environment. The staff concludes that the use of these reactor trip functions is acceptable.

The current licensing basis for St. Lucie Unit 2 is described in UFSAR Section15.2.5.1.1, which consists of two separate FLB event categories with different acceptance criteria based upon frequency of occurrence.

Small Feedwater Line Break (UFSAR Chapter 15.2.5.1.1.1)

Break Size: $\leq$ 0.2 ft^2
Frequency: 6.2 x 10^{-3} per year, "low probability"
Criteria: RCS peak pressure less than 110 percent of design (2750 psia)
Main Steam System (MSS) peak pressure less than 110 percent of design
Site boundary doses not to exceed a small fraction of 10 CFR Part 100 guidelines.

Feed Line Break with LOOP (UFSAR Chapter 15.2.5.1.1.2)

Break Size: Any size including > 0.2 ft^2 (double ended rupture of a 6 inch diameter pipe)
Frequency: 1.0 x 10^{-7} per year,[1] "exceedingly low probability"
Criteria: RCS peak pressure less than 120 percent of design (3000 psia)
MSS peak pressure less than 110 percent of design
Site boundary doses not to exceed a small fraction of 10 CFR Part 100 guidelines.

The proposed amendment (Reference 5) did not differentiate a "small" from a "large" FLB. The new analysis separately evaluates a break size spectrum from 0.005 ft^2 to 0.375 ft^2 to determine the limiting size with respect to peak RCS pressure, peak MSS pressure, and DNB degradation. This approach was prompted by the change in the licensing basis for the timing of the LOOP. The 3-second delay in the timing of LOOP (see Sections 3.4.1.3 and 3.4.1.4) effectively removes any impact of RCP coastdown on calculated peak pressures.

With the delay of the four-pump coastdown, the staff had concerns that a previously unanalyzed, but creditable, active single failure may promote worst consequences. An RAI was issued (RAI-6a of Reference 8) requesting an evaluation of a FLB with failure of a fast bus transfer (FFBT). This scenario results in a two-pump coastdown at turbine trip. In response to

[1] Event frequency based upon St. Lucie Unit 2 UFSAR Section 15.2.5.1.1, numbers for large FLB at 1.0 x 10^{-4} per year in combination with an independent LOOP at 1.0 x 10^{-3} per year.

this RAI, the licensee provided a qualitative assessment crediting a low SG level reactor trip. The staff did not accept this response and subsequently issued RAI-3 of Reference 20. Based upon the response to RAI-3, it was clear that a new licensing basis needed to be established that focused more on active single failures and less on LOOP (which no longer effects peak pressure calculations due to 3-second delay). SRP 15.2.8 (NUREG-0800 Draft Rev. 2) defines peak pressure criteria based upon probability: less than 110 percent of design for low probability events and less than120 percent for very low probability events. Based upon review of these SRP guidelines and the licensee's response to RAI-3, the staff defines the following acceptance criteria for the different FLB event categories:

1. Small Feedwater Line Break ($\leq$ 0.2 ft^2)
    a. Peak RCS pressure does not exceed 110 percent of the design value (2750 psia).
    b. Peak MSS pressure does not exceed 110 percent of the design value (1100 psia).
    c. Site boundary doses would not exceed a small fraction of the 10 CFR Part 100 guidelines.

2. Small Feedwater Line Break ($\leq$ 0.2 ft^2) with single failure (FFBT)
   - Same criteria as Small FLB above.

3. Large Feedwater Line Break (>0.2 ft^2)
   - Same criteria as Small FLB above.

4. Large Feedwater Line Break (>0.2 ft^2) with single failure (FFBT)
    a. Peak RCS pressure does not exceed 120 percent of the design value (3000 psia).
    b. Peak MSS pressure does not exceed 110 percent of the design value (1100 psia).
    c. Site boundary doses would not exceed a small fraction of the 10 CFR Part 100 guidelines.

Limiting FLB scenarios with respect to peak RCS pressure, peak MSS pressure, and DNB degradation need to consider a LOOP in accordance with SRP 15.2.8: (1) simultaneous with the pipe break, (2) during the accident (with consideration for any approved mechanistic delay after turbine trip), (3) or never. Note that all of the above FLB scenarios shall consider a LOOP when performing the long-term decay heat removal capability and site boundary dose assessments.

<u>Peak RCS Pressure:</u>

The licensee's response to RAI-3 of Reference 20 provided results from a sensitivity study on break size and single failure. An FFBT was identified as the most limiting single failure. A graph illustrating peak RCS pressure as a function of break size and single failure was included in this response. A review of this graph identifies that the limiting cases for the 110 percent of design pressure criteria (event categories 1, 2, and 3 above) would be the small FLB with FFBT event (0.20 ft^2 break) and the large FLB event (0.28 ft^2 break). Both of these cases challenge the 110 percent pressure criteria and both of these cases bound the small FLB event. The limiting case for the 120 percent of design pressure criteria (event category 4 above) would be the large FLB with FFBT event (0.28 ft^2 break). Based upon review of the inputs and assumptions of these limiting cases, the staff accepts the peak RCS pressure calculations.

Peak MSS Pressure:

The original St. Lucie Unit 2 submittal (Reference 5) included a sensitivity study on break size to determine the limiting peak MSS pressure case. The limiting FLB case with respect to peak MSS pressure occurs with a relatively small break size of 0.05 ft^2. The calculated peak pressure for this case remained below the acceptance criteria of 110 percent of design (1100 psia). Note that this case bounds all four event categories above. Based upon review of the inputs and assumptions of this limiting case, the staff accepts the peak MSS pressure calculation.

DNB Degradation:

The original St. Lucie Unit 2 submittal (Reference 5) included a sensitivity study on break size to determine the limiting DNBR case. Note that these sensitivity cases, including limiting case, did not consider a single failure. An FFBT at RTBO would result in a two-pump coastdown and promote higher DNB degradation. In response to RAI-6a of Reference 8, the licensee stated that the FLB with FFBT event would be bounded by the pre-trip SLB with FFBT event for “fuel failure and dose considerations.” The staff recognizes that both limiting fault events are classified as Condition IV, however the SLB events are licensed to “within” 10 CFR Part 100 guidelines; whereas the FLB events are licensed to a “small fraction” of 10 CFR Part 100. A review of the limiting pre-trip SLB with FFBT reveals that the DNB SAFDL is not violated (no fuel failure is predicted to occur). Based on the limiting pre-trip SLB with FFBT case results indicating no fuel failure, the staff accepts the judgement that the FLB with FFBT is bounded by the pre-trip SLB with FFBT scenario.

During a recent review in support of a different licensee's extended power uprate, the staff acquired a better understanding of a previously unanalyzed condition potentially related to the FLB event. During an inside containment FLB event, a SIAS may be generated on high containment pressure. Since all charging pumps start on a SIAS, the potential exists that the mass addition due to the charging pumps may exacerbate the transient. An RAI was issued (RAI-6b of Reference 8 and RAI-4 of Reference 20) requesting an evaluation of a FLB with SIAS scenario. In response, the licensee stated that the current licensing basis for St. Lucie Unit 2 was to credit the PORVs to prevent lifting of the PSVs during the long term FLB scenario analyzed in UFSAR Section 10.4.9A. Further, current Emergency Operating Procedures require operators to maintain pressurizer level and adjust charging and high pressure safety injection (HPSI) to prevent the pressurizer from going solid. Based on the information provided in response to these RAIs, the staff agrees that an inside containment FLB with SIAS will not result in unacceptable consequences.

Along with conservative inputs and initial conditions, a break size spectrum was completed to determine the limiting cases for peak RCS pressure, peak MSS pressure, and DNB degradation. The results of these cases demonstrate acceptable consequences for each FLB event category (defined above) for St. Lucie Unit 2 with up to 30 percent SG tube plugging. Based upon the above review, the staff finds the results of the FLB event analyses acceptable.

3.4.2.11 Decrease in Reactor Coolant Flow Rate

A mechanical or electrical failure in RCPs or a fault in the power supply to the pumps may cause loss of RCS flow. A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result, potentially violating SAL DNBRs. Reactor protection and safety systems are actuated to mitigate the transient. The licensee indicated in the response to RAI-19.a of Reference 7 that it performed analyses of the 1-out-of-4, 2-out-of-4 and 4-out-of-4 RCP trip events and confirmed that the total loss of RCS flow (the 4-out-of-4 RCP trip event) is the bounding case with respect to the DNBR criterion. The licensee did not analyze 3-out-of-4 RCP trip event because 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 RCPs (one in each loop). Any failure which would result in loss of power to three pumps also would result in loss of power to the fourth pump. The licensee provided the analysis of the total loss of RCP flow event in Section 5.1.14 of Reference 5.

The licensee analyzed this event using the following computer codes: RETRAN calculates the nuclear power, the RCS temperature and pressure, and the core flow during the transient; VIPRE calculates the heat flux and DNBRs based on the nuclear power and RCS temperature, pressure, and flow from RETRAN. The DNBR calculations are based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow are assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP. The licensee also assumed a large absolute value of the Doppler-power coefficient with the most positive MTC for full-power operation. These assumptions maximize the core power and are, therefore, conservative. The analysis assumes a limiting DNB axial power shape in VIPRE for the calculation of DNBR. This shape provides the most limiting minimum DNBR for the LOF event. A maximum, uniform SGTP level of 30 percent is assumed in RETRAN analysis. The reactor trip is assumed to occur when the core flow reaches low-flow trip setpoint.

The results of the analysis show that the calculated DNBR will remain above the SAL DNBRs, ensuring that no fuel damage is predicted to occur. With respect to over pressurization, the LOCV event discussed in Section 5.1.10 of Reference 5 will bound the LOF event because the LOCV event causes a turbine trip with the LONF. The net effect of the turbine trip and LONF for the LOCV event is a total loss of RCS secondary system heat sink, which results in the greatest challenge to RCS primary and secondary system pressurization. Therefore, the LOCV event remains the limiting event in terms of the peak RCS primary and secondary system pressures, which are shown to be less than 110 percent of the design pressures. The staff agrees with the licensee that the maximum RCS primary and secondary system pressures will be bounded by that of the LOCV event and also remain below 110 percent of their respective design pressure for the LOF events. Therefore, the staff determines that the analysis meets the acceptance criteria of SRP Section 15.3.2 with respect to the integrity of the RCS pressure boundary and fuel rods, and thereby concludes that the analysis is acceptable.

3.4.2.12 Total Single RCP Shaft Seizure/Sheared Shaft

The events postulated are an instantaneous seizure of the rotor or break of the shaft of an RCP in a PWR. During the transient, flow through the affected loop is rapidly reduced, leading to a reactor trip on a low-flow signal. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure (locked rotor) event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. Because peak pressure, cladding temperature and DNB occur very early in the transient, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Therefore, the licensee analyzed the limiting case, the rotor seizure event.

For the analysis of this event, the licensee used RETRAN for calculation of the loop and core flow rate during the event, the nuclear power transient, and the RCS pressure and temperature transients, and VIPRE for the DNBR calculation. The DNBR calculations are based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow are assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP. In the RCS pressure and temperature calculations, the licensee assumed maximum values for the initial power level, RCS pressure and temperature with inclusion of the measurement uncertainties to maximize the calculated peak RCS pressure. The licensee also assumed a large absolute value of the Doppler-power coefficient with the most positive MTC for full-power operation. These assumptions maximize the core power and are, therefore, conservative. Following the locked rotor, a reactor trip is initiated on an RCS flow-low signal. As part of the 30 percent SG tube plugging amendment (Reference 5), the licensee has opted to use a mechanistic LOOP as a result of grid collapse induced by the plant trip. In this mechanistic approach, the licensee used a delay time of 3 seconds between the turbine trip and a LOOP. The delay time of 3 seconds is consistent with the value used in the AOR for St. Lucie Unit 2 that also applied the mechanistic LOOP approach (see Section 3.4.1.4 for bases for acceptance). A LOOP causes a simultaneous loss of feedwater, flow, condenser inoperability and coastdown of all RCPs. However, during the review, the licensee indicated that the analysis for LOOP scenarios on the non-safety 6.9 kv RCP buses showed that the immediate loss of one 6.9 kv bus and thus, loss of power to the associated two RCPs following a reactor/turbine/generator trip is possible as a result of a plant-centered component failure. The staff requested the licensee to address the effect of the immediate loss of two RCPs due to a plant-centered component failure (such as FFBT) on the results of the analysis of the RCP rotor seizure event. In response, the licensee performed the analysis of the rotor seizure event with an FFBT (resulting in the immediate loss of two RCPs following turbine trip), and provided the results of analysis in the response to RAI-10 of Reference 20. The results of the pressurization calculation show that the calculated peak RCS pressure is 2646 psia, which meets the acceptance criterion of less than 2750 psia (110 percent of the design pressure).

In addressing the staff's concern regarding the validity of the thermal-hydraulics modeling of inlet flow distribution and cross-flow characteristics during a two-pump coastdown, the licensee stated that the impact of a two-pump coastdown on local flow characteristics are offset by conservative assumptions and modeling techniques in the safety analysis methodology. In response to RAIs 9 and 10 of Reference 20, the following conservatisms have been identified, which may be credited to offset any potential impact of the two-pump local flow characteristics:

1. In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the two-pump coastdown.

2. In VIPRE, the peak power assembly with the peak rod at the Fr design limit and a low peak-to-average power ratio is modeled at the core location corresponding to the minimum flow assembly.

3. In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate Fr corresponding to the DNB SAFDL. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

Items 1and 2 above compensate for nonconservative aspects of the thermal-hydraulics model relative to the two-pump coastdown inlet flow distribution and cross-flow characteristics. These conservative modeling assumptions ensure that the minimum DNBR calculations remain conservative. If the calculated minimum DNBR was below the SAFDL, item 3 could have been credited to ensure that the predicted number of failed fuel rods remain conservative. Further, the results of the analysis show that the total percentage of fuel rods calculated to experience DNB is less than 1 percent of the fuel in the core, which is significantly less than the value (13.7 percent) used in the dose consequences analysis for this event.

Based on its review, the staff found that the calculated maximum RCS pressure remains less than 110 percent of the design pressure, and the total percentage of rods calculated to experience DNB is small and is less than the value assumed in the acceptable dose consequence analysis for this event. Therefore, the staff concludes that the analysis of the RCP rotor seizure event meets the acceptance criteria of SRP Section 15.3.3 and is acceptable.

3.4.2.13 Uncontrolled Control Element Assembly Bank Withdrawal at Power

A CEA bank withdrawal at power event may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. Such an event causes an increase in fuel and coolant temperature as a result of the core-turbine power mismatch. Reactor trips, including the variable high power (VHP) trip, HPP trip, TM/LP trip and high local power density trip, provide plant protection.

The licensee performed the analyses with acceptable methods. The RETRAN code calculates the nuclear power transient, and the RCS pressure and temperature transients. The FACTRAN code calculates the heat flux based on the nuclear power from RETRAN. The VIPRE code calculates the DNBR using heat flux from FACTRAN and the flow, inlet core temperature and pressure from RETRAN. The VHP trip is assumed to occur at 112.2 percent of nominal full-power. The HPP trip is assumed to occur when the pressurizer pressure reaches 2415 psia. The TM/LP trip is modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index. The Δ-power (a power increase above the initial power level) feature of the VHP trip is assumed to trip the reactor when the Δ-power reaches the setpoint of 30 percent of nominal full-power for the cases initiated from less than full power (20, 50, and 60 percent of nominal full-power). This 30 percent Δ-power trip setpoint includes setpoint uncertainties, power measurement uncertainties and accounts for excore decalibration due to CEA withdrawal. For the full-power case, the reactor is assumed to trip when the Δ-power reaches the setpoint of 11 percent of nominal full-power. Decalibration of the excore detectors as the CEAs withdraw is modeled since this effect may reduce the indicated excore detector power and thereby delay the reactor trip. In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow are assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 15).

The licensee analyzed cases with both minimum and maximum reactivity feedback coefficients, and performed a sensitivity study of the effects of initial power levels (20, 50, 65 and 100 percent of full power) and reactivity insertion rates (from 1 pcm/sec to 60 pcm/sec, which bounds the maximum reactivity insertion rate of 53 pcm/sec resulting from the simultaneous withdrawal of two control rod banks).

The results of the analyses show that with the combination of the VHP, HPP and TM/LP trips, the DNBRs do not fall below the SAL DNBRs and the peak heat generation rate is less than the limiting value for fuel melting for all cases. Therefore, fuel integrity and adequate fuel cooling are maintained. The calculated peak RCS pressure is less than 110 percent of the design pressure. The staff finds that the analyses meet the acceptance criteria of SRP Section 15.4.2 with respect to fuel integrity and RCS pressure boundary limits. Therefore, the staff concludes that the analyses are acceptable.

3.4.2.14 Uncontrolled CEA Withdrawal From a Subcritical Condition

A CEA withdrawal from a subcritical condition may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The VPH trip and the rate-of-change of power-high trip provide protection against this event.

For the analysis of this event, the licensee used TWINKLE for the average power generation calculation, FACTRAN for the hot rod heat transfer calculation, and VIPRE for the DNBR calculation. The DNBR calculation is based on the previously approved STDP, which is the traditional design method with parameter uncertainties applied deterministically in the limiting direction. In the DNBR calculation, the RCS flow rate is based on the thermal design flow and the RCS pressure is the nominal pressure minus the uncertainty. Since the event is analyzed from hot-zero power, the steady-state STDP uncertainties on core power and RCS average temperature are not used in defining the initial conditions. The analysis assumes a conservatively low value for the Doppler-power defect and the maximum value for the MTC to maximize the peak heat flux. Reactor trip is assumed to occur on the VPH trip signal with the setpoint of 35 percent of full power, which includes a 20-percent uncertainty. The analysis assumes that maximum positive reactivity insertion rate of 53 pcm/sec that exceeds that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed (30 in/min). The DNBR calculation assumes the most limiting axial and radial power shapes associated with the two highest-worth banks in their highest-worth position. The initial power level is assumed to be below the power level expected for any shutdown conditions (10^{-9} fraction of nominal power). The combination of the highest reactivity addition rate and lowest initial power produces the highest peak heat flux, resulting in the lowest calculated minimum DNBR, and is conservative. The results of the analyses show that the DNBRs do not fall below the SAL DNBRs, the peak heat generation rate is less than the limit value for fuel melting and the calculated peak RCS pressure is less than 110 percent of the design pressure.

The staff has reviewed the assumptions related to the reactivity worth and reactivity coefficients used in the analysis and found that they maximize the calculated heat flux, thereby minimizing the calculated DNBRs, and are conservative. The staff has reviewed the calculated consequences of this event and found that they meet the requirements of GDC 10, in that the SAL DNBRs are not exceeded. The licensee also meets the requirements of GDC 20, in that the reactivity control system can be initiated automatically so that SAL DNBRs are not exceeded. In addition, the licensee meets the requirements of GDC 25, in that a single malfunction in the reactivity control system will not cause the SAL DNBRs to be exceeded. Therefore, the staff concludes that the analysis satisfies the acceptance criteria of SRP Section 15.4.1 and is acceptable.

3.4.2.15 Control Element Assembly Drop Event

A CEA drop event is defined as the inadvertent release of a single or subgroup of CEAs causing it/them to drop into the core. The occurrence of a single electrical or mechanical failure in a CEA drive mechanism would result in a CEA drop.

In this event, the core power initially decreases due to the insertion of negative reactivity resulting from the dropped control rod. Moderator and Doppler temperature feedback causes power to return to its initial level at a reduced RCS temperature and pressure condition. The event results in a localized increase in the radial peaking factor, which causes DNBR to decrease.

The licensee analyzed a number of cases with a spectrum of dropped CEA worth from 100 pcm to 1000 pcm. The St. Lucie Unit 2 CEA drop detection system is assumed inoperable with no credit taken for the turbine run back feature. With a decrease in power, the turbine load is not reduced, but is assumed to remain the same as before the CEA drop occurs. This results in power mismatch between the primary and secondary system, which leads to a cooldown of the RCS. In addition, the automatic withdrawal capability of the control element drive mechanism is disabled. The licensee used the acceptable RETRAN, VIPRE and ANC computer codes to analyze the DNBR consequences for this event. The results show that the SAL DNBRs will not be violated. The staff finds that the analysis used the approved methods and showed that the fuel damage will not occur. Therefore, the staff concludes that the analysis is acceptable because it meets the acceptance criteria of SRP Section 15.4.3 with respect to the fuel cladding integrity.

3.4.2.16 Uncontrolled Boron Dilution

Unborated water can be added to the RCS via the CVCS. This may happen because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator must stop this unplanned dilution before the shutdown margin is eliminated.

SRP section 15.4.6 requests that at least 15 minutes is available from the time the operator is made aware of an unplanned boron dilution event to the time a total loss of shutdown margin(criticality) occurs during power operation, startup, startup, hot standby, hot shutdown, and cold shutdown (Modes 1 through 5). A warning time of 30 minutes is required during refueling (Mode 6).

As discussed in UFSAR Section 7.7.1.1.11, the boron dilution alarm system (BDAS) provides a direct indication of a boron dilution in process. In the case that the BDAS is inoperable, UFSAR contains requirements for maximum frequency of RCS chemistry sampling. These sampling frequencies ensure that the specified criteria are met to ensure sufficient time is available to the operators, from the detection of dilution until criticality is achieved, to mitigate the consequences of this event.

The licensee analyzed the boron dilution event to ensure that the analysis results meet the SRP 15.4.6 acceptance criteria for all Modes, and remain consistent with the BDAS and sampling frequency for Modes 3 through 6. The licensee indicated (in the response to RAI-20.a of Reference 7) that the analyses performed in support of the 30-percent SGTP application result in tables defining the applicable critical and initial boron concentrations with one, two and three charging pumps operating, consistent with the operational conditions specified in UFSAR Table 13.7.2-3. The analysis approach used in generating the boron concentration tables is consistent with the acceptable WCAP-9272 reload methodology (discussed in Section 3.3.1 of this evaluation). The cases provided in the licensing report (Reference 5) reflect the general approach of analyzing the boron dilution event with representative cases as specified in Section 5.1.19.2 of Reference 5. For Modes 5 and 6, the maximum flow from one charging pump is assumed as the dilution flow rate. For Mode 4, the maximum values of flow from two and three charging pumps are assumed for the cases of the plant on the shutdown cooling system (SCS) and the case of the plant operating with at least one RCP in operation. For the Mode-3, -2, and -1 cases, the maximum capacity from three charging pumps are assumed for the dilution flow. The method used for the analysis consists of a generic fluid dilution mixing model (the response to RAI-3.a of Reference 8), which is consistent with the model used in the AOR and is acceptable. The analysis used shutdown margins that are consistent with the minimum values required by the core operating limits report for the shutdown modes. The coolant forced flow sources are modeled in accordance with the TS requirements for the operable SCS and RCPs (the response to RAIs 3.a and 3.b of Reference 8). In maximizing the effect of the boron dilution, the analysis uses the minimum amount of water in the RCS to mix with the incoming unborated water (the response to RAI-3.a of Reference 8). The result shows that the operator has at least 15 minutes for Modes 1 through 5 and 30 minutes for Mode 6 between an alarm announcing an unplanned boron dilution and the loss of shutdown margin. The results demonstrate the compliance with the SRP 15.4.6 acceptance criteria with respect to the operator action time to terminate the boron dilution.

The staff reviewed (1) conditions at the time of the unplanned dilution, (2) causes, (3) initiating events, (4) the analytical model used for analyses, (5) the values of parameters used in the analytical model, and (6) results of the analyses. The staff finds that the licensee’s analyses have adequately accounted for the changes required for operation of the plant with 30 percent SGTP. The analyses use acceptable methods and conservative assumptions, and the results meet the acceptance criteria of SRP Section 15.4.6. Therefore, the staff concludes that the boron dilution analysis is acceptable.

3.4.2.17 Control Element Assembly Ejection

CEA ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. The reactor trip signals from VPH or high rate-of-change of power trip provide protection against this event.

The staff evaluates the consequences of a CEA ejection accident to determine the potential damage caused to the reactor coolant pressure boundary (RCPB) and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The staff reviews initial conditions, rod patterns and worth, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 28 for ensuring that the effects of postulated reactivity accidents do not result in damage to the RCPB greater than limited local yielding and do not cause sufficient damage to significantly impair the capability to cool the core. Specific acceptance criteria contained in SRP Section 15.4.8 and used to evaluate this accident include:

1. Reactivity excursions should not result in a radially averaged enthalpy greater than 280 cal/gm at any axial location in any fuel rod.

2. The maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the "Service Limit C" as defined in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code.

The licensee performed the CEA ejection accident with the methods documented in Westinghouse topical report WCAP-7588, Revision 1-A (Reference 19). As discussed in Section 3.3.3 of this evaluation, the staff has determined that the previously approved Westinghouse topical report is applicable to the St. Lucie Unit 2 analysis. The licensee analyzed two set of cases for the accident, one initiated from full power and one initiated form zero power. The analysis of both of these cases uses both beginning-of-cycle (BOC) and end-of-cycle (EOC) kinetics. Table 5.1.20-1 of Reference 5 lists the values of the initial plant parameters (such as initial power level, ejected rod worth, delay neutron fraction). The analysis uses a minimum value for the delayed neutron fraction, a minimum value of the Doppler-power defect and maximum values of ejected CEA worth, which conservatively results in a higher nuclear power increase rate and the maximum amount of energy deposited in the fuel following CEA ejection. The analysis also uses a positive MTC for the zero power BOC case because a positive MTC results in positive reactivity feedback and thus increases the magnitude of the power increase. The analysis credits the VPH trip (a high setting for full power cases and lower setting for zero power cases) to trip the reactor. The results show that the calculated values of maximum fuel pellet enthalpy for the four analyzed cases are 151.1 cal/gm for full power BOC, 70.8 cal/gm for zero power BOC, 141.7 cal/gm for full power EOC and 77.4 cal/gm for zero power EOC. These calculated values of peak fuel enthalpy fall below the limit of 280 cal/gm specified in SRP Section 15.4.8. The calculated values also fall within the Westinghouse-specified analysis limit of 200 cal/gm. In addition, based on the generic assessment in WCAP-7588, Revision 1-A, which assumed an ejected rod worth that is approximately two times the value used in the St. Lucie Unit 2 rod ejection analysis (the response to RAI-21 of Reference 7), and the peak pressure results documented in the current UFSAR, the staff agrees with the licensee that the peak reactor pressure will be less than that which would cause stresses to exceed the faulted condition stress limits, and thus satisfies the guidance of SRP Section 15.4.8 with respect to the RCS pressure limit. The analysis also showed that, for all cases, the peak hot-spot fuel centerline temperature remains below the fuel melting temperature.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident, such as a CEA Ejection event, at lower enthalpies than the limits currently specified in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during reactivity insertion accidents will be much lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel that has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/gm.

The staff has concluded that, although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated reactivity insertion accidents in operating plants with fuel burnups up to 60 gigawatt days per metric ton of uranium, such as St. Lucie Unit 2, will neither (1) result in damage to the RCPB, nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to significantly impair the capability to cool the core as specified in current regulatory requirements. Based on this, the staff finds that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed 30 percent SGTP. Therefore, the staff concludes that the proposed 30 percent SGTP is acceptable with respect to the rod ejection accident.

3.4.2.18 CVCS Malfunction

A CVCS malfunction may result in an event that increases RCS inventory. Operator actions, an electrical actuation signal, or a valve failure may cause the CVCS malfunction to occur. Section 5.1.21 of Reference 5 presents the results of the limiting case - the CVCS malfunction initiated from full power caused by an erroneous low-low level signal that actuates a second charging pump and closes the letdown flow control valve to its minimum position. This assumed initiating event is consistent with the current event description in Section 15.5.3.2.2 of the UFSAR. The licensee analyzed this event using the RETRAN code and established the following conditions to maximize the pressurizer water level:

1. The initial reactor power is at 102 percent of the rated power; the RCS pressure is 45 psi below the nominal pressure and the RCS temperature is at 3 ^{0}F above the nominal temperature.

2. The pressurizer sprays and heaters are operable.

3. The PSVs are assumed to open at a setpoint with inclusion of -2 percent tolerance.

4. 30 percent of SG U-tubes are assumed to be plugged.

5. The operators are alerted to the event either by the pressurizer high level alarm (PHLA) at a setpoint of 70 percent of tap span, or a HPP trip.

6. Maximum reactivity feedback conditions are assumed.

The event is analyzed to address the concerns of the pressurizer overfill and, thus, it is assumed to occur without increasing or deceasing the primary coolant initial boron concentration. The case of a CVCS malfunction that causes a boron dilution is discussed in Section 5.1.19 of Reference 5 and is evaluated by the staff in a separate section. For this analysis, operator action is credited to mitigate the event by reducing charging flow or restoring letdown flow. Operator action is assumed to occur at 20 minutes after the PHLA or the HPP trip actuates. The assumed operator action delay time is consistent with the current UFSAR, Section 15.5.3.2.2, and therefore, is acceptable. The assumed single failure is the complete closure of the letdown flow control valve that occurs concurrently with the start of the second charging pump and is consistent with the assumptions used in the AOR. The results of the analysis demonstrate that the pressurizer volume does not become water solid prior to 20 minutes after the PHLA or HPP trip is actuated, assuring that no water is discharged through the PSVs.

During the CVCS malfunction, the changes in core power, RCS temperatures and RCS mass flow are small. With respect to peak RCS and MSS pressures, the event is bounded by the LOCV event described in Section 5.1.10 of Reference 5, which is analyzed with assumptions that are made to conservatively calculate the RCS and MSS pressures. With respect to fuel damage because of low DNBR, the event is bounded by the CEA bank withdrawal at power described in Section 5.1.16 of Reference 5.

Therefore, the staff concludes that the analysis meets the acceptance criteria of SRP Section 15.5.2 with respect to the acceptance criteria of the maximum pressurizer water level, peak RCS and MSS pressures and SAL DNBRs, and is acceptable.

3.4.2.19 Pressurizer Pressure Decrease - Inadvertent Opening of the Pressurizer Relief Valves

An accidental depressurization of the RCS may occur as a result of an inadvertent opening of both of the pressurizer PORVs, an inadvertent opening of a single PSV, or a malfunction of the pressurizer spray system. This event results in a decrease in the RCS pressure. The depressurization of the RCS can cause the fuel to approach to the SAL DNBRs. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip, which is actuated by a TM/LP trip signal.

In the case of St. Lucie Unit 2, the PSV is sized to discharge approximately half the steam flow rate of a PORV, and the pressurizer spray system cannot depressurize the RCS at the rate of two open PORVs. The licensee analyzed the event of opening of both PORVs, which is the limiting depressurization case, resulting in the a lowest value of DNBR.

The licensee used acceptable computer codes to analyze this event: RETRAN calculates the RCS power, pressure and temperature; and VIPRE calculates the DNBRs. In the analysis, the initial reactor power and RCS temperature are assumed to be at their nominal values, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with the minimum value allowed by the plant TS. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in WCAP-11397-P-A. The results of the analysis show that the calculated DNBRs are above the SAL DNBRs, thus ensuring that no fuel damage will occur for this event.

Based on its review discussed above, the staff finds that the acceptable methods and adequate assumptions are used in the analysis, and the results of the analysis show that no calculated DNBR values fall below safety DNBR limit. Therefore, the staff concludes that the analysis meets the acceptance criteria of SRP Section 15.6.1 with respect to the core SAL DNBRs, and is acceptable.

3.4.2.20 Primary Line Break Outside Containment

A small primary line break outside containment may result from a break in a letdown line, instrumentation line, or sample line. The case presented in Section 15.6.3.1.7 of the UFSAR is the double-ended break of the letdown line outside containment upstream of the outside containment isolation valve because it is the largest line break and results in the largest release of the reactor coolant to the environment. In support of the proposed amendment to operate with 30-percent SGTP, the licensee evaluated the current AOR in USFAR Section 15.6.3.1.7 to account for a decrease in minimum RCS flow from 355,000 gpm to 335,000 gpm, and increase in SGTP to 30 percent. This was done by reviewing the key input and assumptions of the AOR and determining the impact of any adverse changes. The license indicated that other than reduced RCS flow and increased SGTP, there are no adverse changes relative to key parameters identified in the AOR.

The licensee indicated (in the response to RAI-24 discussed in Reference 7) that with the RCS flow reduced to 335,000 gpm, the initial RCS average and hot-leg temperature will be about 2.5 ^{0}F and 5 ^{0}F higher, respectively, than that shown in UFSAR Figure 15.6.3.1-9, but these temperatures do not affect the letdown line break flow rate, which is dependent on the upstream (i.e., cold leg) temperature and pressure. Figure 15.6.3.1-9 in the UFSAR shows that prior to reactor trip, RCS temperatures remain constant. Further, the RCS pressure will decrease prior to the reactor trip as shown in UFSAR 15.6.3.1-10. The RCS pressure is determined by the pressurizer conditions and the loss of reactor coolant volume caused by the break. In comparison, the pressurizer conditions - including the range of initial pressure and liquid level, charging flow and heat capacity - are not changed by the increase in SGTP. Therefore, the pressure transient shown in USFAR 15.6.3.1-10 and the sequence of events in UFSAR Table 15.6.3.1-8 remain valid for the case with a 30-percent level of SGTP, and the pre-trip leakage will remain unchanged.

The AOR in UFSAR Section 15.6.3.1.7 assumed that following the reactor trip, the leak rate was 45 lbm/sec for 10 minutes after the SIAS was initiated on low pressurizer pressure, which closed the letdown line isolation valves. The licensee indicated (in the response to RAI-24 discussed in Reference 7) that the leak rate was based on analyses performed with the CESEC code, which showed that the letdown flow decreased from about 49 lbm/sec at reactor trip caused by the low pressurizer pressure to less than 41 lbm/sec just before closure of the letdown line isolation valves at about 82 seconds after reactor trip. Therefore, the letdown rate of 45 lbm/sec for 10 minutes assumed in the analysis results in a greater integrated leak flow and higher dose release, and is conservative. In addition, the impact of initial RCS flow and SGTP on assumed post-trip leak flow rate will be small because cold-leg temperature decreases and equilibrates to a value determined by the MSSV setpoint, which remains unchanged for a case with an increase in SGTP. The post-trip pressure decrease is caused by the coolant contraction as the RCS average temperature decreases to a value determined by the MSSV setpoint. With a same temperature in the SG secondary side, a higher RCS average temperature will results in a greater heat transfer capability from the RCS primary to secondary system, while a smaller SG heat transfer area will decrease heat transfer capability. Therefore, the amount of depressurization resulting from the coolant contraction will be slightly greater when the initial average temperature is higher for cases with a reduced RCS flow, and will decrease slightly when the available heat transfer area becomes smaller because of a higher level of SGTP. The effects of a reduced RCS flow and a decreased SG heat transfer area on depressurization are small, and offsetting to each other.

Based on the review discussed above, the staff agrees with the licensee that the decrease in the minimum RCS flow from 355,000 gpm to 335,000 gpm, and an increase to 30 percent SGTP have a negligible effect on this event. Therefore, the staff concludes that the AOR documented in UFSAR 15.6.3.1.7 remains valid and acceptable.

3.4.2.21 SGTR with a Concurrent Loss of Offsite Power

A steam generator tube rupture (SGTR) event causes direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and SG safety or atmospheric relief valves. Reactor protection and engineered safety features are actuated to mitigate the accident and restrict the offsite dose within the guidelines of the 10 CFR Part 100 limits. The staff's review covers postulated initial core and plant conditions, method of thermal and hydraulic analysis, sequence of events assuming a LOOP, assumed reactions of reactor system components, functional and operational characteristics of the reactor protection system, and the results of the accident analysis. The staff review for SGTR discussed in this section is focused on calculations of the mass releases that are used for calculating radiological consequences, and follow the acceptance criteria specified SRP Section 15.6.3.

In support of its proposed increase in SGTP, the licensee performed an SGTR thermal-hydraulic analysis for calculation of the radiological consequences. The analysis is performed using a methodology consistent with the current AOR (i.e., the CESEC code). A core power of 102 percent of the rated thermal power is used in this analysis and 30 percent of the SG tubes are assumed to be plugged in each SG. A SG tube break area of 0.336 in^2, consistent with the AOR, is assumed. The analysis credits the TM/LP low pressurizer pressure trip signal to trip the reactor and to prevent violation of the SAL DNBRs. Consistent with the AOR, following an SGTR, a LOOP is assumed to occur concurrent with the reactor trip resulting in the release of steam to the atmosphere via the SG ADVs and/or safety valves. Also, consistent with the current analysis, the licensee assumed that the operators completed the actions necessary to terminate the equilibrium break flow and the steam releases from the ruptured SG within 30 minutes after the event initiation, at which time plant cooldown is initiated using the unaffected SG ADVs. The resulting break flow mass transfer is then used to calculate the radiological consequences of the SGTR.

The results of the analysis show that the RCS primary and secondary pressures do not exceed 110 percent of the design pressures, and the TM/LP trip assures that the SAL DNBRs are met. The staff also found that the analysis of the SGTR adequately accounted for the proposed

SGTP of 30 percent and was performed using approved computer codes. Further, the assumptions used in this analysis were consistent with the AOR in maximizing the primary-to-secondary leakage. Therefore, the staff concludes that the SGTR analysis meets the acceptance criteria of SRP 15.6.3 with respect to the guidance for calculating the maximum mass release, and is acceptable.

3.4.3 Large-Break LOCA and Small-Break LOCA (SBLOCA) Analyses

The licensee performed the analysis of the LOCA analysis to support operation with 30 percent SGTP for St. Lucie Unit 2 with a core containing both UO_2 fuel rods and gadolinia burnable absorber fuel rods with Zircaloy-4 and ZIRLO cladding. The licensee presented the results of the analysis of the LBLOCA in Section 5.2.3, the SBLOCA in Section 5.2.4, and the long term cooling in Section 5.2.5 of Reference 5.

3.4.3.1 Large-Break LOCA Analysis

The LBLOCA analysis is performed with 102 percent of the rated power, and a maximum SGTP of 30 percent in each SG. The proposed TS value of 335,000 gpm is assumed for the RCS flow rate. The licensee analyzed LBLOCAs with various break sizes ranging from 0.4, 0.6, 0.8 and 1.0 double-ended-guillotine breaks in the reactor pump discharge leg (DEG/PD) and identified that the worst break case is the 0.6 DEG/PD break, resulting in a highest peak cladding temperature (PCT) of 2130 ^{0}F.

The licensee performed an analysis for cases with no ECCS failure, with failure of an EDG, and with failure of a low pressure safety injection (LPSI) pump, and identified that the most limiting single failure is the case with no failure of ECCS equipment, since it results in the highest PCT. The case with no ECCS failure is the limiting because it maximizes the amount of safety injection that spills into the containment. This results in the lowest containment pressure, which, in turn, minimizes the reflood rate into the core, and thus maximizes the PCT. An analysis also showed that a combination of minimum temperature and pressure and maximum volume for the safety injection tanks and minimum refueling water tank temperature results in the highest PCT.

The licensee performed the LBLOCA analysis using the NRC-approved 1999 evaluation model (References 11 and 13) for CE-designed PWRs. The evaluation module uses several computer codes: CEFLASH-4A for blowdown hydraulic analysis; COMPERC-II for the RCS refill and reflood hydraulic analysis; HCROSS and PARCH for calculation of steam cooling heat transfer coefficients; STRIKIN-II for computation of the PCT and maximum cladding oxidation, FATES3B for determination of the initial steady state fuel conditions and COMZIRC for calculation of the core-wide cladding oxidation.

3.4.3.2 Small-Break LOCA Analysis

The SBLOCA analysis was performed with 102 percent of the rated power, and a maximum SGTP of 30 percent in each SG. The proposed TS value of 335,000 gpm was assumed for the RCS flow rate. The licensee analyzed three SBLOCA cases with break sizes of 0.04, 0.05 and 0.06 ft^2 in the reactor pump discharge leg and identified that the worst-break case is the 0.05 ft^2 break, resulting in a highest PCT of 1943 ^{0}F. The 0.04, 0.05 and 0.06 ft^2 breaks are at the upper end of the range of break sizes for which the hot rod cladding heatup transient is terminated by injection from a HPSI pump. It is within this range of break sizes that the limiting SBLOCA is located. For smaller breaks, the transient does not exhibit as much core uncovery as the breaks of 0.04, 0.05 and 0.06 ft^2. For larger breaks, injection from the safety injection tank and a HPSI pump recovers the core and terminates the heatup of the cladding before the cladding temperature reaches the PCT of the limiting SBLOCA. The break spectrum analysis was performed for the fuel rod conditions at the burnup that results in the maximum initial stored energy in the fuel. The rod internal pressure was adjusted to cause cladding rupture to occur at the time when the highest PCT occurs.

The analysis used the failure of an EDG as the most limiting single failure. This failure causes the loss of both a HPSI pump and a LPSI pump, and results in a minimum of safety injection water being available to cool the core. Based on the limiting single failure and the design of the St. Lucie Unit 2 ECCS, 75 percent of the flow from one HPSI pump is credited in the SBLOCA analysis. The LPSI pump is not credited in the analysis since the RCS pressure does not decrease below the LPSI pump shutoff head during the portion of the transient that is analyzed.

The licensee performed the SBLOCA analysis using the NRC approved Supplement 2 Model (S2M) (References 12 and 13) for CE-designed PWRs. The S2M uses several computer codes: CEFLASH-4AS for the blowdown hydraulic analysis until the time the safety injection tanks (SITs) begin to inject; COMPERC-II for the hydraulic analysis for case when injection from the SITs begins; PARCH for calculation of pool boiling cooling heat transfer coefficients; STRIKIN-II for computation of the PCT and maximum cladding oxidation; and FATES3B for determination of the initial steady state fuel conditions. However, STRIKIN-II was not run because the PCT calculated by PARECH is not significantly affected by the portion of the hot rod heatup transient calculated by STRIKIN-II. This approach is consistent with the SBLOCA AOR.

The staff has reviewed the LBLOCA and SBLOCA analyses. As a result, the staff finds that the approved analytical methods and computer codes are used and the result of the analysis show that the PCT of less than 2200 ^{0}F, cladding oxidation of less than 17 percent of the total cladding thickness and metal-water reaction of less than 1 percent of all of the metal in the cladding cylinders surrounding the fuel are within the acceptance criteria specified in 10 CFR 50.46 for the LOCA analysis. Therefore, the staff concludes that the analyses for LBLOCAs and SBLOCAs are acceptable.

3.4.3.3 Post-LOCA Long-Term-Cooling (LTC)

The regulatory requirement for LTC is provided in 10 CFR 50.46(b)(5) which states “after any calculated successful initial operation of the emergency core cooling system (ECCS), the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.” Although the SRP provides some guidance, it essentially repeats the regulatory requirement. In practice, following successful calculated blowdown, refill, and reflood after initiation of a LOCA, the LTC requirement will be met if the fuel cladding remains in contact with water so that the fuel cladding temperature remains essentially at or below the saturation temperature. A potential challenge to LTC is that boric acid could accumulate within the reactor vessel, precipitate, and block water needed to keep the fuel cladding wetted by water.

As shown in Figures 5.2.5.3-3 and 5.2.5.3-6 of Reference 5, the licensee uses two different LTC methods, depending on the break size. If the break is sufficiently small, the SCS is used. For larger breaks, simultaneous hot-leg and cold-leg injection from the HPSI pumps is used to maintain core cooling and avoid boric acid precipitation. The analysis assumes that the plant cooldown is initiated within 1 hour following a LOCA by releasing the steam through the turbine bypass system (if ac power is available) or through the atmospheric dump system (if ac power is unavailable). Between 2 and 6 hours following a LOCA, the HPSI pump discharge lines are realigned so that the total injection flow is divided equally between the hot leg and cold legs. At about 16 hours (decision time) into the transient, if the RCS pressure is equal to or greater than 130 psia, the plant cooldown to the SCS entry conditions is initiated by using the SG, and then the SCS is initiated for LTC. If the RCS pressure decreases below 130 psia, simultaneous hot-leg and cold-leg injection from the HPSI pumps is maintained for LTC.

The licensee used the same methods (documented in CENPD-254-P-A) it used for the AOR for the LTC analysis to support the 30-percent SGTP application. The LTC analytical methods consist of four computer codes: BORON for determination of the boric acid concentration in the core; NATFLOW for calculation of the natural circulation flow rate; CELDA for determination of the reactor system long term primary system depressurization and refill for small break; and CEPAC for simulation of SGs, including the operation of SG ADVs and determination of the secondary system temperature. The LTC analyses include a boric acid precipitation analysis and a decay heat removal analysis. The boric acid precipitation analysis uses BORON to demonstrate that the maximum concentration in the core remains below the solubility, thereby preventing the precipitation of boric acid in the core. The decay heat removal analysis uses NATFLOW, CELDA and CEPAC to demonstrate that the core remains covered with two-phase liquid in the long term, thereby ensuring that the core temperature is maintained at an acceptably low value.

In the boric acid precipitation analysis, a minimum reactor vessel volume is assumed for the boric acid accumulation to maximize the boron concentration, thus maximizing the potential of boron precipitation. The volume consists of the volume from the top of the core support plate to the bottom elevation of the hot legs that is inside the core baffle and above the baffle, which is inside the core barrel. Also, the values used in the analysis for the boric acid concentration of liquid injected from the safety injection tanks and refueling water tank are greater than that specified in the TSs, thus maximizing the potential for boric acid precipitation to occur. In addition, the analysis assumes a boric acid concentration of 27.6 weight-percent as the solubility limit of boric acid. This is the solubility limit of boric acid in saturated water at atmospheric pressure. Atmospheric pressure is a conservative minimum pressure, resulting in a lower boric acid solubility limit, following a LOCA. The results of analysis show that a minimum flow of 275 gpm from a HPSI pump to both the hot-leg and cold-leg of the RCS, initiated between 2 and 6 hours following a LOCA, maintains the boric acid concentration in the core below the solubility limit of 27.6 weight-percent for the limiting case, a large cold-leg break.

The decay heat removal analysis is performed with 102 percent of the rated power, and a maximum SGTP of 30 percent in each SG. The SG steam dump and the RCS cooldown are assumed to begin at 1 hour after a LOCA and the cooldown rate is maintained at 75 ^{0}F/hr, which is consistent with the cooldown rate used in the AOR, until flow is limited by the ADVs. If the break is sufficiently small, the SCS is used, while for larger breaks, simultaneous hot-leg and cold-leg injection from a HPSI pump is used to maintain core cooling. The licensee analyzed the LTC cases with various break sizes and showed that, for all cases analyzed, the core remains covered with two-phase liquid, thereby, ensuring that core temperatures are maintained at acceptably low values. The analysis also identified a decision time of 16 hours and a decision pressure of less than 130 psia for determining the use of the simultaneous hot-leg and cold-leg injection or the SCS for LTC. The results of the analysis show that at the decision point (with the RCS pressure of 130 psia), for breaks as large as 0.038 ft^2, the SCS can be used as the long-term decay heat removal method, and for breaks as small as 0.007 ft^2, simultaneous hot-leg and cold-leg injection can be used to remove decay heat following a LOCA. The overlap in these two ranges ensures that an appropriate long-term decay heat removal can be achieved.

The LTC analysis uses the approved methods and the results of the analysis demonstrate that an adequate core cooling can be maintained without boric acid precipitation. Therefore, the staff concludes that the LTC analysis is acceptable.

3.5 TS Changes

The following are the proposed TS changes:

3.5.1 TS 1.37, “Unrodded Planar Radial Peaking Factor (F_{xy})”

The definition of Unrodded Planar Radial Peaking Factor is deleted. This deletion is consistent with the deletion of F_{xy} in TS 3.2.2, and is an editorial change. Therefore, the deletion is acceptable.

3.5.2 TS Figure 2.1-1, “Reactor Core Thermal Margin Safety Limit Lines-Four Reactor Coolant Pumps Operating”

TS Figure 2.1-1 is changed to reflect the revised minimum RCS flow of 335,000 gpm and analysis methodology. The TS changes adequately reflect the acceptable safety analyses discussed in Section 3.4 of this evaluation, which demonstrate that the applicable SRP Chapter 15 acceptance criteria are met at the revised conditions. Therefore, the staff concludes that the change is acceptable.

3.5.3 TS Table 2.2-1, “Reactor Protective Instrumentation Trip Setpoint Limits”

The specification for the RCS flow of 355,000 gpm in the footnote to TS Table 2.2-1 is changed to refer to the COLR limit specified in COLR Table 3.2-2, which specifies that the RCS flow is greater or equal to 335,000 gpm. The safety analyses discussed in Section 3.4 of this evaluation demonstrate that the applicable SRP Chapter 15 acceptance criteria are met for transients initiated from plant operation with low flow trip setpoint based on the reduced RCS flow. Therefore, the staff concludes that the changes are acceptable.

3.5.4 TS Figure 2.2-3, “Thermal Margin/Low Pressure Trip Setpoint Part 1 (Y_1 Versus A_1)”

TS Figure 2.2-3 is replaced with a clearer figure. There are no changes to the values in this figure. The changes are editorial in nature, and therefore, are acceptable.

3.5.5 TS 3.1.1.4, “Moderator Temperature Coefficient”

The TS changes modify the MTC for power levels greater than 70 percent of rated thermal power (RTP) from +3 pcm/^{0}F to a linear ramp from +5 pcm/^{0}F at 70 percent of RTP to 0 pcm/^{0}F at 100 percent of RTP. The safety analyses discussed in Section 3.4 with the revised MTC values show that the applicable acceptance criteria in SRP Chapter 15 are met. Therefore, the changes are acceptable.

3.5.6 Surveillance Requirements in TS 3/4 2.1, "Linear Heat Rate"

TS 4.2.1.3, "Excore Detector Monitoring System," is changed to replace reference to F_{xy} with reference to F_r^T in TS 4.1.2.3.c. In addition, TSs 4.2.1.3.d, 4.2.1.3.e, and 4.2.1.3.f are added to include a function W(z) in the linear heat surveillance using the excore detector monitoring system. The function W(z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation and is related to the COLR.

As discussed in Section 3.2, for excore monitoring, F_{xy} surveillance is replaced by LHR surveillance, with application of W(z) penalties. This is consistent with operation using BEACON already in use at St. Lucie Unit 2. Therefore, the changes are acceptable.

3.5.7 TS 3/4 2.2, "Total Planar Peaking Factor - $F^T{}_{XY}$"

As discussed in Section 3.2 of this evaluation, constant monitoring for LHR with the Incore Detector Monitoring System makes F_{xy} surveillance redundant when performing surveillance with incore detectors. Therefore F_{xy} surveillance specified in the entire section of TS 3/4.2.2 for incore monitoring can be deleted, consistent with previous changes for St. Lucie Unit 1, a CE-designed plant.

3.5.8 TS Table 3.2-2, "DNB Margin Limits"

TS Table 3.2-2 is changed to relocate the DNB parameters including cold-leg temperature, pressurizer pressure, and RCS flow rate limits to the COLR. The lower limit of the RCS flow rate remains in this TS. As discussed in TS Bases 3/4.2.5, limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient analyses. The staff finds (in Section 3.4 of this evaluation) that the limits are consistent with the safety analysis assumptions and have been analytically demonstrated that the SAL DNBRs are not violated throughout applicable analyzed transients. By relocating these DNB parameters to the COLR, the COLR values would reflect the cycle-specific operating conditions. Also, the proposed TS retains the minimum limit for RCS total flow, based on an acceptable analysis (discussed in Section 3.4 of this evaluation) to assure that a lower flow rate than reviewed by the staff would not be used. Further, the acceptable methods are used to determine the limits of the DNB parameters and the methods are referenced in the TSs (as discussed in Section 3.5.11 of this evaluation). The staff determined that the proposed changes are consistent with the guidance of GL 88-16, which allows licensees to remove cycle-dependent variables from TS provided that the values of these variables are included in a COLR and are determined with NRC-approved methodology, which is referenced in the TS. Therefore, the staff concludes that the changes are acceptable.

3.5.9 TS 5.3.1, "Fuel Assemblies"

The licensee will use ZIRLO fuel rod cladding for new fuel assemblies in St. Lucie Unit 2, which is a CE-designed plant. As indicated in Reference 13, the staff has approved the implementation of ZIROLO cladding in CE nuclear power fuel assembly design. TS 5.3.1 is changed to include both Zircaloy and ZIRLO as fuel rod cladding material and reworded to be similar in level of detail as NUREG-1432, Revision 2 (Reference 10). Therefore, the staff concludes that the proposed TS 5.3.1 is acceptable.

3.5.10 TS 5.4.2, "Volume"

The design feature of the RCS volume specified in TS 5.4.2 is deleted. The licensee uses specific RCS volumes in the safety analyses as inputs consistent with the assumed SGTP level. The staff finds that the deletion of the specification of the RCS volumes in the Design Features section of TSs is consistent with NUREG-1432, Revision 2 (Reference 10). Specifically, Standard TS 4.0, "Design Features," for CE plants, does not include the RCS volume. Therefore, the staff concludes that the TS changes are acceptable.

3.5.11 TS 6.9.1.11b, "Core Operating Limits Report (COLR)"

TS 6.9.1.11.b provides a list of titles of topical reports (TRs) that document the methodologies used to determine the values of cycle-specific parameters that are included in the COLR. The proposed change adds nine reports (as References 56 to 64) to the list.

NRC GL 88-16 (Reference 9) allows licensees to remove cycle-dependent variables from TSs provided the values of these variables are included in a COLR and are determined with NRC-approved methodologies that are referenced in the TSs. The staff finds, as discussed in Sections 3.1 through 3.4 of this evaluation, that the methodologies in the added TRs are acceptable for use in support of St. Lucie Unit 2 licensing applications, and the inclusion of the titles of the referenced TRs in the St. Lucie TSs is in compliance with the GL 88-16 requirements. Therefore, the staff concludes that the TS changes are acceptable.

3.5.12 TS Conforming Changes Related to the Changes Discussed In Sections 3.5.1 through 3.5.10 of This Evaluation

TS Index page II is changed to remove Section 1.37, "Unrodded Planar Radial Peaking Factor, F_{xy}" and renumber Section 1.38 to Section 1.37, "Ventilation Exhaust Treatment System." TS Index page V is changed to delete the title of Section 3/4 2.2, "Total Planar Peaking Factor - F^T_{xy}." TS Index page XVII is changed to delete Section 5.4.2, "Volume." The staff finds that those changes in the TS Index pages are editorial changes and are consistent with the changes discussed in Sections 3.5.1, 3.5.5, and 3.5.10 of this evaluation, respectively. Therefore, the staff concludes that the changes are acceptable.

TS 3.2.4.a and 3.2.4.b, "Azimuthal Power Tilt (T_q)," are modified to delete F^T_{xy} requirements. TS 3/4.10.2, "Moderator Temperature Coefficient, Group Height, Insertion and Power Distribution Limits," is changed to delete references to TS 3.2.2. TS 6.9.1.11.a, "Core Operating Limits Report (COLR)," is changed to reflect the deletion of TS 3.2.2 and changes to TS Table 3.2-2. The staff finds that these changes are consistent with the proposed TS changes for deletion of TS 3.2.2 and relocation of DNB parameters to the COLR as discussed in sections 3.5.7 and 3.5.8 of this evaluation. Therefore, the staff concludes that the changes are acceptable.

4.0 TECHNICAL EVALUATION - RADIOLOGICAL DOSE CONSEQUENCES

The staff reviewed the technical analyses, related to the radiological consequences of DBAs, that were done by the licensee in support of this proposed license amendment. Information regarding these analyses was provided in Enclosure 1 of the September 18, 2003, submittal and in the supplemental letters. The staff reviewed the assumptions, inputs, and methods used by the licensee to assess these impacts and did independent calculations to confirm the conservatism of the licensee's analyses. However, the findings of this safety evaluation input are based on the descriptions of the analyses and other supporting information submitted by the licensee. The staff also considered relevant information in the St. Lucie Unit 2 UFSAR and the St. Lucie Unit 2 TSs. Only docketed information was relied upon in making this safety finding.

4.1 Reactor Coolant and Secondary Plant Radiation Source Term for SGTR DBA

For the SGTR DBA, in which releases occur from the secondary plant, the initial concentrations of radionuclides in the RCS and the SGs are assumed to be the maximum values permitted by TSs. The licensee derived the RCS source term from Table 11.1-2 of the St. Lucie UFSAR. The activities given in Table 11.1-2 are based on an assumption of 1-percent failed fuel, and the radioiodine data were normalized to the specific activity TS limit of 1.0 μci/gm dose equivalent I-131. The proposed definition of dose equivalent I-131 and the thyroid dose conversion factors (DCFs) of the International Commission on Radiological Protection report ICRP-30 (which are equivalent to the rounded values from Federal Guidance Report 11 for iodine isotopes) were used in this adjustment. Non-iodine species were normalized to the TS limit of $100/\bar{E}\gamma$.

The TS limit for secondary coolant specific activity is 0.1 μci/gm dose equivalent I-131. The noble gases are assumed to be released immediately.

The intent of the TSs on specific activity is to ensure that assumptions made in the DBA radiological consequence analyses remain bounding. As such, the specification should have a basis consistent with the basis of the dose analyses. Historically, licensees have calculated the dose equivalent I-131 using thyroid DCFs, since the limiting analysis result was the thyroid dose. The AST analyses, however, determine the Total Effective Dose Equivalent (TEDE) rather than the whole body dose and thyroid dose as done previously. The staff believes that the FGR-11 DCFs identified as "effective" should be used instead of the thyroid DCFs. In response to a staff RAI on this issue, the licensee showed that the using the thyroid DCFs in the definition of dose equivalent I-131 results in higher radioiodine concentrations in the primary coolant than would be obtained using the effective DCFs. Table 4.1-1 tabulates this evaluation:

Table 4.1-1
Dose Equivalent Iodine-131 Concentrations

	RCS dose equivalent Iodine-131 Activities, uCi/gm	
Isotope	Based on Thyroid DCF	Based on Effective DCF
I-131	0.8133	0.8019

I-132	0.1692	0.1669
I-133	1.0111	0.9969
I-134	0.1011	0.0997
I-135	0.5055	0.4985

The staff agrees that the thyroid DCFs would maximize the inventory of radioiodines in the RCS and the SGs. Given the conservative nature of the dose equivalent I-131 concentrations, the staff finds the licensee's definition and calculation acceptable.

4.2 Atmospheric Dispersion Estimates

4.2.1 Meteorological Data

The licensee used onsite hourly meteorological data collected during calendar years 1996 through 2001 to generate new atmospheric dispersion factors (χ/Q values) for use in this proposed license amendment. These data were provided for staff review in the form of hourly meteorological data files (for input into the ARCON96 atmospheric dispersion computer code) and joint frequency distributions (for input to the PAVAN atmospheric dispersion computer code). The data were used to generate control room, exclusion area boundary (EAB), and low population zone (LPZ) χ/Q values for the SGTR DBA evaluated in this license amendment request. The resulting atmospheric dispersion factors represent a change from those used in the current UFSAR Chapter 15 accident analysis.

The licensee assumed the releases for the onsite (control room) and offsite (EAB and LPZ) atmospheric dispersion analyses were ground level. Input to ARCON96 consisted of hourly wind data from the 10-meter and 57.9-meter levels on the onsite meteorological tower, whereas input to PAVAN consisted of a joint frequency distribution table compiled using wind data from the 10-meter level. Stability class was calculated using the temperature difference between the 57.9-meter and 10-meter levels on the onsite meteorological tower. The licensee stated that its onsite meteorological monitoring system complies with RG 1.23, "Onsite Meteorological Programs."

The staff performed a quality review of the ARCON96 hourly meteorological database using the methodology described in NUREG-0917, "Nuclear Regulatory Commission Staff Computer Programs for Use with Meteorological Data." Further review was performed using computer spreadsheets. Examination of the data revealed that stable and neutral atmospheric conditions were generally reported to occur at night and unstable and neutral conditions were generally reported to occur during the day, as expected. Wind speed, wind direction, and stability class frequency distributions for each measurement channel were reasonably similar from year to year and generally consistent with that presented in Chapter 2.3 of the St. Lucie Unit 2 UFSAR. A comparison of joint frequency distributions derived by the staff from the ARCON96 hourly data with the joint frequency distributions developed by the licensee for input into PAVAN showed reasonably good agreement.

In summary, the staff reviewed the available information relative to the onsite meteorological measurements program and the resulting ARCON96 and PAVAN meteorological data input files provided by the licensee. On the basis of this review, the staff concludes that these data provide an acceptable basis for making estimates of atmospheric dispersion for design basis accident assessments.

4.2.2 Control Room Atmospheric Dispersion Factors

The licensee used guidance provided in draft RG, DG-1111, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessment at Nuclear Power Plants,” to generate the control room atmospheric dispersion factors. [Draft RG DG-1111 has subsequently been reissued as RG 1.194.] The licensee calculated control room χ/Q values using the ARCON96 computer code (NUREG/CR-6331, Revision 1, "Atmospheric Relative Concentrations in Building Wakes"). Input to ARCON96 included hourly onsite meteorological data for the last 6 months of 1996, all of 1997, 1998, and 1999, the first 6 months of 2000, and all of 2001. The last 6 months of 2000 data were not included because of low data recovery. The data recovery rate for the period-of-record provided as input to ARCON96 exceeded 94 percent.

The control room envelope is pressurized during normal plant operation with outside air makeup taken through air intakes located in the north and south walls of the reactor auxiliary building. These two air intakes are located within the same 90E wind direction window for the two assumed SGTR DBA release pathways (i.e., the condenser and the closest MSSV or ADV). In Question 18 of the RAI letter dated July 9, 2004, the staff requested clarification concerning the control room air intake configuration during normal operation and whether the flow rates through each air intake are always equal. In its RAI response to the staff dated September 21, 2004 (Reference 22), the licensee stated that the normal mode of operation for the control room ventilation system is for makeup air to be drawn from both the north and south outside air intakes in parallel with the isolation valves for both air intakes fully opened. This results in a balanced flow between the two intakes. In this configuration (prior to control room isolation), the licensee conservatively used the higher dispersion factors for the two intake locations to model the air being drawn into the control room through the two air intakes.

The licensee assumed the control room is isolated 30 seconds after the LOOP. The licensee also assumed the operators act to un-isolate the control room and initiate filtered air makeup 90 minutes after the start of the event in order to maintain positive pressure and air quality within the control room. By observing the radiation monitors located in the outside air intake ducts, the licensee stated that operators are assumed to be able to identify and open the outside air intake with the lesser amount of radiation. The licensee assessed the dose from the filtered makeup contribution using the dispersion factors for the more favorable air intake location throughout the rest of the 30-day duration of the dose calculation.

In Question 19 of the RAI letter dated July 9, 2004, the staff asked how the operators would be able to continuously observe radiation monitor levels at each intake throughout the 30-day event period to ensure that the less contaminated intake is always being used to pressure the control room during wind shifts and changing release rates from multiple release pathways. In its RAI response to the staff dated September 21, 2004, the licensee committed to revising plant procedures to identify the need for operators to be aware of changing meteorological conditions and how such changes may affect which outside air intake path provides the lower radiation levels.

During the entire course of the event, the licensee assumed unfiltered inleakage enters the control room. At the beginning of the event, prior to control room isolation, the licensee modeled unfiltered inleakage using the dispersion factors associated with the less favorable control room intake location. Following control room isolation, when both control room intakes are closed, the licensee used dispersion factors corresponding to a location that is either the less favorable control room intake location (for condenser releases) or at the midpoint between both control room intake locations (for closest MSSV/ADV releases). At the time when the operators are assumed to un-isolate the control room by opening the more favorable air intake, the licensee used the dispersion factor for the more favorable control room intake location.

In Question 23 of the RAI letter dated July 9, 2004, the staff inquired why the licensee did not model the unfiltered inleakage pathway using the most limiting dispersion factors associated with the bounding potential unfiltered inleakage pathway for the duration of the event. In its RAI response to the staff dated September 21, 2004, the licensee stated that Unit 2 unfiltered inleakage testing demonstrated that a large portion of the control room unfiltered inleakage comes from the B switchgear room which is fed from fans that take suction in the vicinity of the south control room intake. Since the atmospheric dispersion factors for the south control room intake are lower than the other possible receptor points, assigning the unfiltered inleakage to other possible receptor points is conservative.

Staff qualitatively reviewed the inputs to the ARCON96 computer runs and found them generally consistent with site configuration drawings and staff practice. The two potential release pathways (i.e., the condenser and the closest MSSV/ADV) were modeled as ground-level point sources with the difference in heights between the release point and receptor taken into consideration. The building area used to model building wake effects was conservatively set equal to zero. The staff made an independent evaluation of the resulting atmospheric dispersion estimates by running the ARCON96 computer model and obtained similar results.

In summary, the staff reviewed the licensee’s assessments of control room post-accident dispersion conditions generated from the licensee’s meteorological data and atmospheric dispersion modeling. The resulting control room χ/Q values are presented in Table 2. On the basis of this review, the staff concludes that the χ/Q values presented in Table 2 are acceptable for use in the SGTR DBA control room dose assessment.

4.2.3 EAB/LPZ Atmospheric Dispersion Factors

The licensee calculated EAB and LPZ χ/Q values using the PAVAN computer code (NUREG/CR-2858, "PAVAN: An Atmospheric Dispersion Program for Evaluating Design Bases Accident Releases of Radioactive Material from Nuclear Power Stations"). A joint frequency distribution derived from the 1997 through 2001 onsite 10-meter wind data was provided as input to PAVAN. Stability class was calculated using the temperature difference between the 57.9-meter and 10-meter levels on the meteorological tower. The data recovery rate for the period-of-record provided as input to PAVAN exceeded 93 percent.

The staff qualitatively reviewed the inputs to the PAVAN computer runs and found them generally consistent with site configuration drawings and staff practice. The licensee considered all releases to be ground level and assumed a building minimum cross-sectional area of 1565 m^2. The staff made an independent evaluation of the resulting atmospheric dispersion estimates by running the PAVAN computer model and obtained similar results.

In summary, the staff reviewed the licensee's assessments of EAB and LPZ post-accident dispersion conditions generated from the licensee's meteorological data and atmospheric dispersion modeling. The resulting EAB and LPZ χ/Q values are presented in Table 3. On the basis of this review, the staff concludes that the χ/Q values presented in Table 3 are acceptable for use in the SGTR DBA EAB and LPZ dose assessments.

4.3 <u>Accident Dose Calculations</u>

In accordance with the guidance in RG 1.183, a licensee is not required to reanalyze all DBAs for the purpose of the application, just those affected by the proposed changes. On approval of this amendment, the AST and the TEDE criteria will become the licensing basis for all subsequent changes to the SGTR DBA radiological analyses intended to show compliance with 10 CFR Part 50 requirements. In keeping with this guidance, the licensee did an evaluation of previously analyzed DBAs to decide which, if any, were affected by the proposed amendment. From the results of this evaluation, the licensee re-analyzed the radiological consequences of the SGTR DBA.

4.3.1 SGTR with a Concurrent Loss of Offsite Power

The accident considered is the complete severance of a single tube in one of the SGs, resulting in the transfer of RCS water to the ruptured SG. The primary-to-secondary break flow through the ruptured tube following a SGTR results in radioactive contamination of the secondary system. A reactor trip occurs, safety injection actuates, and a LOOP occurs concurrently with the reactor trip. As this LOOP renders the main condenser unavailable, the plant is cooled down by releases of steam to the environment.

For the purpose of this analysis, the licensee assumed that the reactor trip occurs at 379.2 seconds after the SGTR DBA. Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for a SGTR DBA. RG 1.183 states that a LOOP should be assumed to be concurrent with the SGTR DBA. In a request for additional information response, the licensee addressed the differences between the recommendation in the RG and their analysis. The licensee provided a time line comparing the two scenarios to show that the assumed scenario is conservative. In this time line, the most important aspect between the two scenarios is the time at which the control room is assumed to isolate. If the LOOP occurs at the time of the SGTR, the control room isolation occurs at 30 seconds. If the LOOP is delayed to the time of the reactor trip, the control room isolation occurs at 409.2 seconds (379.2 sec for trip + 30 second delay). Given this delay and the associated steaming rates and atmospheric dispersion factors provided by the licensee in the RAI response, the staff agrees that the assumptions used by the licensee are conservative. The information provided (primarily the delayed response of the control room isolation) provides reasonable assurance that the delayed LOOP assumption is conservative.

The licensee states that:

1. The assumed plant response to these analyzed events was in accordance with the current plants licensing basis, which includes consideration of limiting single failures and a LOOP. This was done in order to maximize the postulate radiological consequences.

2. The limiting single active failure assumed in the AST analysis for the SGTR DBA is the failure that results in the loss of one train of the control room emergency air cleanup system. This assumed failure serves to maximize doses to the control room operators.

Based upon the fact that the licensee has stated that the postulated doses are maximized, the NRC staff finds these assumptions acceptable.

The licensee states that no fuel damage is postulated to occur because of a SGTR. Two radioiodine spiking cases are considered. The first assumes that a pre-incident radioiodine spike occurred just before the event and the RCS radioiodine inventory is at the maximum value (for 100 percent power) permitted by TSs. The second case assumes the event initiates a coincident radioiodine spike. Radioiodine is released from the fuel to the RCS at a rate 335 times the normal radioiodine appearance rate for 8 hours.

Per Reference 7, the licensee assumed a total primary-to-secondary break flow of 77,007 lbm, starting at event initiation and continuing for 0.5 hours. The licensee assumes that a portion of the break flow flashes to vapor and is immediately released to the environment with no mitigation or holdup. The flashing fraction ranges from 0.1719 to 0.066. The portion of the break flow that does not flash is assumed to mix with the bulk water of the SG. In addition to the break flow, the licensee assumes there is primary-to-secondary leakage at the maximum value permitted by TSs. Primary-to-secondary leakage is assumed to be 216 gpd into the bulk water of the ruptured SG and 216 gpd total into the bulk water of the unaffected SG. The primary-to-secondary leakage continues until the RCS temperature is less than 212 EF (at about 12 hours).

The radionuclides in the bulk water are assumed to become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient. The licensee postulated that the tubes in the unaffected SG would remain covered by the bulk water. The licensee assumes that the radionuclide concentration in the SG is partitioned such that 1 percent of the radionuclides in the unaffected SG's bulk water enter the vapor space and are released to the environment. The partition coefficient does not apply to the flashed break flow.

The steam release from the unaffected SG continues until the shutdown cooling is in operation and the steam released from SG is terminated (8 hours). In the original application the licensee's analysis assumed the steam release continued until the shutdown cooling is in operation. In a subsequent RAI response to the NRC's question why this was conservative, the licensee committed to revise plant procedures to ensure that, in the event of a plant accident involving a secondary release, the SGs are isolated once shutdown cooling is placed in service. The revised procedure(s) will be in place at the time of implementation of this amendment. The NRC staff relied upon this commitment to insure that the SGTR DBA radiological analysis is conservative.

The NRC staff reviewed the licensee's description of the density used in converting volumetric leak rates to mass leak rates for the primary-to-secondary leakage. In RAI Question 5 of Reference 22, the NRC staff requested confirmation that the density values assumed in the SGTR DBA analysis are consistent with the plant surveillance tests used to show compliance with the primary-to-secondary leak rate TS. The licensee stated that it is in the process of revising its primary-to-secondary leak rate monitoring (Chemistry procedures) to include compensation for RCS density differences between the cold monitoring condition and the hot conditions assumed in the analyses. The licensee stated that although other "plant procedures are sufficiently conservative to ensure that the assumed primary-to-secondary leak rate will not be exceeded," that "FPL commits to revise the Chemistry procedures discussed in the response prior to startup from SL2-15 currently scheduled for late January 2005." Based upon the commitment that these procedures will be in place prior to the startup from SL2-15 and the correction factor to be used is 1.4, the NRC staff finds that the methodology used to model the primary-to-secondary leakage is acceptable. The NRC staff relied upon this commitment to ensure that the SGTR DBA radiological analysis is conservative.

For this event, the control room ventilation system cycles through three modes of operation:

1. Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 1000 cfm of unfiltered inleakage.

2. The control room isolation is initiated on a control room intake radiation monitor signal, which is set at two times background. For this event, it is conservatively assumed that the control room isolation signal is delayed until the release from the ADVs/MSSVs is initiated at 409.2 seconds (379.2 sec for trip + 30 second delay). A 30-second delay is applied to account for the diesel generator start time, fan start and damper actuation time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 1000 cfm of unfiltered inleakage, and 2000 cfm of filtered recirculation flow.

3. At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside to the control room. During this operational mode, the air flow distribution consists of 450 cfm of filtered makeup flow, 1000 cfm of unfiltered inleakage, and 1550 cfm of filtered recirculation flow. The total assumed inleakage rate is greater than that determined in recently performed tracer gas infiltration tests.

With the adoption of the two previously described commitments, the staff has determined that The licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 1. The EAB, LPZ, and control room doses estimated by the licensee for the SGTR DBA were found to meet the applicable accident dose criteria and are, therefore, acceptable. The staff did independent calculations and confirmed the licensee's conclusions.

4.3.2 Analysis of the Impact of the 30-percent SGTP to Other Radiological Accidents

In its January 7, 2005, supplement (Reference 22), the licensee performed an evaluation of the impact of the proposed change on the SLB, the FLB, the CEA ejection, the inadvertent opening of an MSSV, the locked rotor/sheared shaft, letdown (primary) line break, the loss-of-coolant, and fuel-handling accidents. The impact of the change on a waste gas decay tank rupture was also evaluated. The evaluation considered the changes on RCS liquid mass, reduction in steam flow out the SG after an accident, changes in failed fuel, and a reduction in the allowed primary to secondary leakage.

The evaluation stated that the majority of the parameters found in radiological consequences do not change as a result of the tube plugging or the WCAP-9272 method as they are governed by regulation, TSs or agreed upon analytical assumptions in licensing interactions. SG inventory, on the other hand, is impacted due to the 30-percent SGTP. A reduction in the heat transfer area in the SG due to the plugging results in a reduction of steam flow. In addition, due to a lower saturation pressure resulting from the 30-percent SGTP, there is an increase in SG liquid mass. Both changes are beneficial when calculating radiological consequences as they are in the conservative direction. The proposed change in the SG tube leakage TS from the current 1 gpm to 0.3 gpm has a significant beneficial effect on the dose consequences. For several accidents the conclusions of the analysis also relied upon the WCAP-9272 calculated fuel failures being less than the AOR.

The evaluation concluded that radiological dose calculations from the current AORs for the accidents for the above-mentioned transients remain valid for the 30-percent SGTP amendment. Based upon the input regarding these analyses, the decrease in allowable TS SG tube leakage from the current 1 gpm to 0.3 gpm and the licensee's verification of less fuel failure than in the current AOR (where credited in the evaluation), the staff believes there is reasonable assurance that the current AORs remain bounding.

4.3.3 TS Section 3.4.6.2, "Reactor Coolant System Operational Leakage"

This proposed change would revise the limited RCS leakage to 0.3 gpm total primary-to-secondary leakage through SGs and 216 gpd through any one SG.

The intent of the TSs for primary-to-secondary leakage from a radiological standpoint is to ensure that assumptions made in the DBA radiological consequence analyses remain bounding. As such, the specification should have a basis consistent with the basis of the dose analyses. The staff agrees that the proposed change is consistent with the re-evaluated SGTR DBA analysis. This assumption is also relied upon to ensure that the accidents and transients evaluated above remain conservative. Accordingly, this assumption is now applicable to all radiological analyses within the design basis. Based upon this consistency with the SGTR DBA analysis and its applicability to the evaluation performed for the accidents and transients evaluated above, the staff finds that the licensee's proposed TS change is acceptable.

4.3.4 Control Room Doses and Unfiltered Inleakage

The NRC staff is currently working toward resolution of generic issues related to control room habitability, in particular, the validity of control room inleakage rates assumed by licensees in analyses of control room habitability. The NRC staff issued GL 2003-01, "Control Room Habitability." The licensee provided a supplemental response to their original response to this GL by letter dated October 29, 2004 (Reference 24). In its response, the licensee reported that inleakage testing using the ASTM E741 tracer gas methodology determined a control room unfiltered inleakage rate of 229 and 26 cfm in the "isolated" and "pressurized" modes, respectively. The proposed values assumed for the SGTR DBA are provided in Table 1. These values plus 10 cfm for ingress and egress are larger than the measured values.

Although the licensee's response to the GL is still under review, the NRC staff has determined that there is reasonable assurance that the St. Lucie Unit 2 control room would be habitable during the SGTR and that this amendment may be approved before the final resolution of the generic issue. The NRC staff bases this determination on (1) the results of the tracer gas testing, the previously mentioned commitments made by the licensee, and (3) the independent confirmatory calculations performed by the NRC staff. The acceptance of the licensee's unfiltered inleakage assumption for the purpose of this license amendment request does not establish that the NRC staff has found the responses to the GL are adequate. The NRC staff may respond to the licensee's GL response under separate cover once its review is complete.

4.4 Conclusions

As described above, the staff reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological impacts of the proposed selective implementation of an AST at St. Lucie, Unit 2. The staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified in Section 2.2 above. The staff compared the doses estimated by the licensee to the applicable criteria identified in Section 2.2. The staff finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and control room doses will comply with these criteria. The staff finds reasonable assurance that the St. Lucie Unit 2, as modified by this proposed amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the proposed license amendment is acceptable with regard to the radiological consequences of postulated DBAs.

This licensing action is considered a selective implementation of the AST. With this approval, the selected application of the AST and the TEDE criteria, if applicable, becomes the design basis for the SGTR DBA radiological analysis. This approval is limited to this specific implementation. The previous offsite and control room accident dose criteria for the SGTR DBA, expressed in terms of whole body, thyroid, and skin doses, are superseded by the TEDE criteria of 10 CFR 50.67 or fractions thereof, as defined in Regulatory Position 4.4 of RG 1.183. Use of other characteristics of an AST or use of TEDE criteria which are not part of the approved design basis, and changes to previously approved AST characteristics, require prior staff approval under 10 CFR 50.67. The selected application of the AST and the TEDE criteria may not be extended to other aspects of the plant design or operation without prior NRC review under 10 CFR 50.67. All future SGTR DBA radiological analyses performed to demonstrate compliance with regulatory requirements shall address the selected characteristics of the AST and the TEDE criteria as described in the St. Lucie Unit 2 design basis.

5.0 TECHNICAL EVALUATION - ELECTRICAL SYSTEM

The licensee is proposing to take credit, in the St. Lucie Unit 2 main SLB analysis, for a delay of at least 3 to 3.3 seconds for a LOOP to occur following turbine trip. This delay had previously been approved for the RCP locked rotor event on the basis of a 1982 Florida grid study. The event analyzed was a large-scale, grid-wide breakup event due to the loss of the St. Lucie Unit 2 generation support (plant trip) as a consequence of the RCP locked rotor event. Such a grid event is a catastrophic occurrence that results in the formation of electrical islands isolated from the rest of the grid and each other. These islands may or may not have enough remaining generation to support adequate and stable frequency and voltages to the customer loads in the island. If automatic and transmission system operator manual load shedding fails to quickly restore adequate frequency and voltage by properly balancing generation and load, a LOOP can occur.

An example of a large-scale, grid-wide breakup event in which electrical islands were formed is the recent August 14, 2003, U.S.-Canadian blackout. These are relatively rare events; although the NRC and nuclear power industry generally believed in the late 1970's and early1980's that if a nuclear plant trip were to result in a LOOP, the grid breakup due to the loss of the nuclear plant generation would likely be the cause. This may have been the result of a Florida grid isolation event that occurred in the late 1970's. Subsequent NRC analysis of operational experience for station blackout and more recently for the risk-informed 10 CFR 50.46 initiative, however, has found that LOOPs due to a nuclear plant trip are much more likely to occur as the result of localized problems occurring in and around the nuclear plant. Although the August 14, 2003, Blackout Report to the President indicates that, if nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience; the staff believes that for the nuclear-plant-trip-initiated consequential LOOP, the localized events will continue to predominate. This belief is based upon the response of electrical power industry stakeholders to correct the initiating elements of the August 14, 2003, blackout and the historically large number of localized consequential LOOPs as compared to large-scale grid consequential LOOPs (nine localized nuclear-plant-trip-initiated consequential LOOP events were found over the years 1986 through 1999, while the staff is not aware of a nuclear plant trip ever causing a large-scale grid LOOP).

Another important consideration in evaluating the expansion of the LOOP assumptions used for the RCP locked rotor event to include the main SLB event, is that the main SLB event includes actuation of ECCS loads while the locked rotor event does not. The mechanisms that could result in a LOOP due to a plant trip, therefore, are not necessarily the same for the RCP electrical buses as compared to the ECCS electrical buses. One item, in particular, is the use of degraded voltage protection on the ECCS electrical buses that is not found on RCP electrical buses.

As a result of the above the staff asked the licensee to provide an evaluation of the St. Lucie plant-specific design features that justify the use of the chosen time delay for the consequential LOOP. The staff asked that the following possibilities that could result in a consequential LOOP be addressed for the St. Lucie site-specific electrical design: degraded switchyard voltage, spurious switchyard breaker-failure-protection circuit actuation, automatic bus transfer failure, and startup transformer failure.

The licensee responded to this request for additional information in a letter dated December 10, 2004. The licensee found that spurious actuation of switchyard breaker failure protection circuitry, automatic bus transfer failure, or a startup transformer failure could result in an immediate loss of one startup transformer and the corresponding 6.9 kV bus (two RCPs) and one 4.16 kV safety bus at St. Lucie Unit 2. The licensee indicated that there are no apparent common-mode failures that would result in loss of both 6.9 kV buses or both 4.16 kV safety buses. They concluded therefore that at least two RCPs, one in each SG loop, would be available immediately following a reactor/turbine/generator trip and, if one 4.16 kV safety bus were immediately lost, it would be re-energized from its EDG. Because the St. Lucie Unit 2 design involves two separate startup transformers with separate power feeds from the 230 kV switchyard down through the startup transformers to the 6.9 kV RCP buses and 4.16 kV safety buses (via 4,16 kV non-safety buses), the staff agrees with these conclusions.

Because the 6.9 kV RCP buses have no degraded voltage protection, the licensee was asked to verify that, if a degraded voltage condition were to occur as a result of the loss of the

St. Lucie generator following a main SLB event, the 6.9 kV loads, including the RCPs, would remain energized and would not trip due to some other protective system action such as overcurrent relaying or motor overload protection. The licensee's response indicates that tripping of the RCPs or main feedwater pumps due to actuation of overcurrent relaying or motor overload protection as the result of degraded voltage is unlikely to occur. This resolves the staff question on this issue.

Because the main SLB event involves the actuation of ECCS, the staff asked the licensee to evaluate the consequences of the delayed LOOP on the performance of the electrical ECCS systems. The staff indicated that the consequences of double energization and its associated vulnerabilities that would occur as the result of the delayed LOOP should be a part of this evaluation. These vulnerabilities include, but are not necessarily limited to: the consequences of starting large continuous-duty motors twice in quick succession with the first start under degraded voltage conditions and the second start with pump discharge valves open; the adequacy of the existing control logic to start loads on offsite power, shed those loads following the LOOP, and subsequently sequence those loads on the EDGs with necessary delay to allow motor residual voltage to decay; interaction between the double energization and circuit breaker anti-pump logic that could lock out the breakers; the capability of the safety batteries to operate the necessary systems during an initial offsite power degraded voltage ECCS start, and subsequently restart the ECCS on EDGs; and the potential to trip motor overload protection or blow fuses as a result of a degraded voltage, double-energization scenario.

The licensee responded to this request for additional information in its letters dated December 10, 2004, and January 7, 2005. These letters provided the response on the adequacy of the existing control logic to start loads on offsite power, shed those loads following the LOOP, and subsequently sequence those loads on the EDGs with necessary delay to allow motor residual voltage to decay. Information provided by the licensee indicates that for a scenario where a unit trip is followed by a SIAS and subsequent delayed LOOP (a typical degraded voltage scenario), the St. Lucie Unit 2 control logic will start the SIAS-actuated loads on offsite power, load shed those loads from their safety buses following the delayed LOOP, and sequence the SIAS-actuated loads onto the EDGs. The response states that the EDG output breakers have a permissive that prevents breaker closure for two seconds after detection of a loss of bus voltage. This time delay specifically allows for voltage decay prior to re-energization of the major motors that start in the first load block upon EDG breaker closure. The St. Lucie Unit 2 control logic precludes overloading of the EDGs and allows for motor residual voltage decay and is, therefore, acceptable.

In its January 7, 2005, responses, the licensee provided an evaluation of electrical equipment operability for a degraded voltage double-energization scenario agreed to with the NRC staff. The scenario under review in this case consists of a pre-existing degraded voltage on the grid with a unit trip caused by main SLB and subsequent SIAS actuation with EDG start on SIAS. Switchyard voltages are such that following transfer to the startup transformers, the 4160 V and 480 V bus voltages are above the degraded-voltage-only relay dropout setpoints. Occurrence of the subsequent SIAS starts the required loads resulting in depression of the voltage and dropout of the degraded-voltage-with-coincident-SIAS relays. In order to meet the conditions as noted, the switchyard voltage will be sufficiently high such that the minimum depressed bus voltages will remain above the loss of voltage relay dropout setpoints. Voltage fails to recover above the degraded voltage + SIAS relay reset setpoints (9 seconds), resulting in timeout of the relays, bus load shed, closure of the EDG breaker, and sequential restart of the SIAS loads with full voltage available for the second motor starts.

The licensee provided information on the susceptibility of circuit breaker anti-pump logic to lockout a safety-related circuit breaker due to interaction with control logic during this scenario. The licensee indicated that the breaker spring charging of the St. Lucie Unit 2 design takes approximately 6 seconds and occurs following closing of the circuit breaker. If a trip and subsequent re-close signal were to come in during this period the breaker would not close and the anti-pump relay would energize and seal in preventing further breaker closing attempts. The licensee analyzed the degraded voltage, double-energization scenario for this vulnerability in its January 7, 2005, response and found that about 14 seconds would elapse between initial breaker closure for SIAS and the second breaker closure for sequencing on the EDG. This provides sufficient time for the spring charging to complete its cycle and the associated limit switches to close to preclude lockout of the circuit breaker. The staff concerns on this topic are, therefore, resolved.

Because batteries were not necessarily sized in consideration of the double-energization scenario that could occur as a result of a degraded voltage delayed LOOP main SLB event, the staff asked the licensee to evaluate this capability. The licensee responses indicate that the safety-related batteries at St. Lucie Unit 2 are sized for a 4-hour duty cycle in the event of a LOOP and EDG start failure (station blackout scenario). In this regard they have been sized to include high demand loads at the beginning of the station blackout and 4 hours later for recovery from the station blackout on the EDGs. For the degraded voltage scenario they note that the battery chargers are capable of operation at reduced current with input voltage as low as 75 percent. However, they provided an evaluation of the battery loading for the degraded voltage double-energization scenario assuming pre-existing degraded voltage conditions result in voltages below the charger capabilities. This evaluation demonstrated that the existing battery calculation is bounding for the degraded voltage, double-energization scenario and resolves the staff questions on this item.

With regard to motor starting capability, the licensee responses stated that nuclear safety-related motors operating on the 4160 V system were procured with a 75-percent voltage starting requirement. Further evaluation of these motors for starting at a lower voltage is therefore not required since the 4.16 kV bus loss of voltage relays are set at 79.25 percent. The licensee stated that nuclear safety-related motors operating on the 480 V system were procured with a 90-percent voltage starting rating, per National Electrical Manufacturers Association (NEMA) MG-1, with the exception of the charging pumps, which have a 75-percent voltage starting rating. The responses stated that an existing evaluation of motor starting for the 480 V loads started on SIAS has shown that there is adequate capability to start at voltages that are just above the 480 V bus loss of voltage relay setpoint of 75.75 percent. The licensee stated that the current degraded voltage calculations assume motor operated valves stall for an initial 6.5 seconds due to low voltage, and commence valve stroke when bus voltages recover. This has previously been evaluated by the licensee to be acceptable with respect to valve operation and motor thermal capability considerations.

Motor and generator standard NEMA MG-1 specifies that large squirrel-cage induction motors be capable of starting twice in succession, coasting to a rest between starts, with the motor initially at ambient temperature and motor terminal voltage at a minimum of 90 percent. Minimum starting voltage of 90 percent is also specified in NEMA MG-1 for medium polyphase induction motors. This puts the double energization of the 480 V motors with 90-percent voltage starting rating outside the specified requirements of NEMA MG-1 during the main SLB degraded voltage, double-energization scenario. The licensee responses stated that permitting restart of the motor before it has a chance to cool off results in a potential for elevated winding temperatures in the motor. The licensee indicated that this would possibly shorten the motor life span due to aging, but would not present a concern for immediate motor failure. The licensee concludes, therefore, that multiple motor starts are not seen as a concern for safety-related component operability and this also applies to those components that are normally controlled by automatic operations and thus this scenario may see multiple starts.

There is some support in the literature for the licensee's statement that permitting restart of the motor before it has a chance to cool off results in a potential for elevated winding temperatures in the motor that would possibly shorten the motor life span due to aging, but would not present a concern for immediate motor failure. NEMA MG-1, Section 20.43.2 states: "It should be recognized that the number of starts should be kept to a minimum since the life of the motor is affected by the number of starts." Institute of Electrical and Electronics Engineers (IEEE) Standard C37.96-2000, *IEEE Guide for AC Motor Protection*, Section 5.2.1 states; "It should be noted that deriving increased output at the price of higher temperatures for any given motor means accepting a shorter life." Volume 6, page 6-56 of the Electric Power Research Institute *Power Plant Electrical Reference Series* states: "Rotor overheating is often far more damaging than stator heating during starting or stalling. Rotors may be weakened so as to fail sooner than they otherwise would have, but no instantaneous melting like that of a fuse element is to be expected under any kind of starting abuse."

Although, as indicated above, there is evidence that starting motors outside of their specified requirements is a fatigue mechanism that can shorten their life rather than an immediate failure concern; this is not explicitly addressed in the standards. Also, as a fatigue mechanism, motor failure is strongly dependent on the operating and maintenance history of the motor, as well as design margins. Consideration could be given to evidence that safety-related motors in nuclear power plant applications are generally well-maintained and some, such as injection pump motors have minimal operating duty. These are the kinds of variables that a motor supplier could take into account in determining whether a limited endorsement is appropriate for motor starting and operation in a degraded voltage, double-energization scenario such as addressed in this evaluation.

Because some motors at St. Lucie Unit 2 will be operating outside their specified requirements during the main SLB degraded voltage, double-energization scenario, the staff believes it is beneficial for the licensee to be aware of conditions that could place St. Lucie Unit 2 in such a condition, which will result in inadequate switchyard voltages at the plant if a main SLB were to occur. This can be accomplished by having St. Lucie verify the availability of the on-line contingency analysis software program. Contingency analysis programs, however, are not always available to transmission system operators, such as during the period leading up to the August 14, 2003, blackout. Events have also demonstrated that the data used in the programs sometimes do not represent actual conditions or capabilities. These shortcomings can be ameliorated to some degree by nuclear power plant notification of contingency analysis program unavailability with subsequent performance of operability determinations, and by verification of actual post-trip switchyard voltages with contingency analysis predicted voltages following inadvertent nuclear power plant trips.

In order to satisfy the staff's concerns, the licensee has committed[2] to the following:

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[2] The licensee agreed with these regulatory commitments by email dated 01/31/2005 from G. Madden, FPL to J. Arroyo, NRC.

1. During periodic communications with the transmission system operator (at least weekly), St. Lucie will verify the availability of the contingency analysis program. Upon becoming aware that the contingency analysis program is unavailable, St. Lucie will perform an operability assessment of the offsite power system, with the exception to unavailability of the contingency analysis program due to routine maintenance.

2. Subsequent to any St. Lucie reactor trip, the resultant switchyard voltages shall be verified to be bounded by the same voltages predicted by the contingency analysis program under the same conditions.

Tripping of motor overload protection is also a concern during a degraded voltage, double-energization scenario. The licensee evaluated the St. Lucie Unit 2 motor overload protection for this scenario in its January 7, 2005, response. With regard to running motors that are not subject to two starts they stated that these had already been evaluated with respect to the degraded voltage relay setpoints, and it was concluded that none of the operating motors would trip on overload at 75-percent voltage before the degraded voltage relays dropout.

With regard to motors that would be subject to two starts during a degraded voltage, double-energization scenario, the licensee response eliminated those motors with overload protection that had no thermal memory capability or where the protection was alarm only. The overload protection without thermal memory capability cannot distinguish between one start and two starts because the protection resets back to zero following each start, and the alarm-only protection will not trip the motor. The licensee response stated that the only overload devices with thermal memory that could cause premature trip due to two successive starts are the devices installed in the 480 V Motor Control Centers (MCCs). Two successive starts could reduce the overload trip time for the second start due to the residual heating of the thermal overload (TOL) heater element from the first start.

The licensee's review of 480 V MCC motors found that motor operated valves (MOVs) actuated by SIAS are not expected to trip prematurely since the TOL function is bypassed and generally provides an alarm-only function. The licensee's review of non-MOV motor characteristics, motor starting time calculations and TOL ratings for 480 V MCC-powered components, shows that the minimum trip time at locked rotor exceeds twice the calculated acceleration time at degraded voltage. This time bounds the degraded voltage, double-energization starts; and this protection, therefore, would not be expected to trip.

The licensee review did find two groups of motors that, because of their relatively long acceleration time and shorter TOL trip time at locked rotor, their overload protection could trip on the second start. These are Hydrazine Pumps 2A and 2B, and Fans HVE-9A and 9B. The licensee response indicates that these loads are needed during a LOCA or CEA injection event, but neither load is needed for the main SLB/SIAS event being evaluated. The need for this equipment during a main SLB/SIAS event is evaluated by another (non-electrical engineering) staff safety evaluation. The potential tripping of this equipment during degraded voltage, double-energization events further supports the discussion above, of the benefit to the licensee to be aware of conditions that could place St. Lucie Unit 2 in such a condition. The above mentioned commitments will also address these staff's concerns.

With regard to the potential LOOP time delays associated with a main SLB event, the licensee's responses indicate that the LOOP could occur between 3-to-12 seconds following reactor/turbine trip or 9 seconds following a SIAS. The response to RAI-1 in the licensee's

January 7, 2005, response indicates a LOOP could occur at approximately 9 seconds following a SIAS with approximately 2 seconds of dead time before the SIAS loads begin to sequence onto the EDGs. The response also indicates that the LOOP could occur at approximately one second following a SIAS with approximately 9 seconds of dead time before the SIAS loads begin to sequence onto the EDGs. Other licensee responses indicated that a one-half LOOP (half the safety loads and half the non-safety loads including RCPs lose offsite power) could occur approximately simultaneously with a reactor/turbine/generator trip.

Based on the above discussion, the staff has the following conclusions regarding the time delays of potential LOOP events:

The LOOP occurring between 3-to-12 seconds following a reactor/turbine/generator trip with no SIAS at that time is unlikely. This is the wide scale grid breakup or voltage collapse event.

The LOOP occurring to the safety loads at approximately 9 seconds following a SIAS with approximately 2 seconds of dead time before sequencing on the EDGs is a more likely LOOP scenario. This is the degraded voltage, double-energization scenario.

The LOOP occurring to the safety loads at approximately 1 second following a SIAS with approximately 9 seconds of dead time before re-sequencing on the EDGs is not as likely as the previous LOOP scenario, but is still possible. This is the loss-of-voltage relay actuation scenario.

A one-half LOOP on the safety and/or non-safety loads (including RCPs) occurring approximately simultaneously with a reactor/turbine/generator trip with or without a SIAS occurring at that time, is a likely LOOP scenario. This is the fast-bus-transfer failure or switchyard breaker-failure-protection spurious actuation scenario.

6.0 TECHNICAL EVALUATION - STEAM GENERATOR TUBE INTEGRITY

In its letter dated September 14, 2004 (Reference 7), the licensee provided its assessment of SG tube integrity considerations as they relate to the requested license amendment. The licensee's response specifically addressed the adequacy of the current technical specification tube plugging limit to ensure that design basis structural margins are maintained during service, given that 30 percent of the tubes in each SG are plugged. The SG tube plugging limit is defined in the technical specifications to be the imperfection depth at or beyond which the tube shall be repaired or removed from service by plugging. The SG tube plugging limit is intended to ensure that tubes are plugged or repaired before safety factors against burst are degraded to values less than would be consistent with the ASME Code, Section III, with allowance for incremental flaw growth between tube inspections and flaw size measurement error. For St. Lucie Unit 2, the specified plugging limit is 40 percent of the nominal tube wall thickness. ("Tube plugging limit" is not to be confused with the level (or percentage) of tubes assumed to be plugged which is the subject of the requested license amendment.) The staff has reviewed the licensee's assessment and concludes that the currently specified plugging limit remains adequate under the requested license amendment since it continues to ensure structural margins consistent with the design basis with an allowance for incremental flaw growth and flaw size measurement error consistent with those assumed throughout the industry. The licensee has also assessed the impact of the 30 percent tube plugging amendment on flow induced vibration of the tubing and concluded that the increase in tube displacements and, thus, tube wear rates and high cycle fatigue are not significant. Based on the above, the staff concludes that the proposed license amendment to permit 30 percent tube plugging in each SG will not adversely impact SG tube integrity.

7.0 STATE CONSULTATION

Based upon a letter dated May 2, 2003, from Michael N. Stephens of the Florida Department of Health, Bureau of Radiation Control, to Brenda L. Mozafari, Senior Project Manager, U.S. Nuclear Regulatory Commission, the State of Florida does not desire notification of issuance of license amendments.

8.0 ENVIRONMENTAL CONSIDERATION

These amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration and there has been no public comment on such finding (69 FR 12873, dated March 18, 2004). Accordingly, these amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of these amendments.

9.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

10.0 REFERENCES

1. Letter from W. Jefferson, Jr. of Florida Power & Light to U.S. Nuclear Regulatory Commission, “St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment WCAP-9272 Reload Methodology and Implementing 30 percent Steam Generator Tube Plugging Limit,” dated December 2, 2003.

2. WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology,” July 1985.

3. Attachment 1 to Reference 1, “A Description of the Proposed Changes and Supporting Justification.”

4. Attachments 3 and 5 to Reference 1, “Marked up and Retyped Copies of the TS Changes.”

5. Attachment 6 to Reference 1, “St. Lucie Unit 2 30-Percent Steam Generator Tube Plugging and WCAP-9272 Reload Methodology Transitiont Project - Licensing Report,” dated October 2003.

6. 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.”

7. Letter from W. Jefferson, Jr. of Florida Power & Light to U.S. Nuclear Regulatory Commission, “St. Lucie Unit 2 Docket No. 50-389, Proposed License Amendment, Request for Additional Information Response, WCAP-9272 Reload Methodology And Implementing 30 percent Steam Generator Tube Plugging Limit,” dated September 14, 2004.

8. Letter from W. Jefferson, Jr. of Florida Power & Light to U.S. Nuclear Regulatory Commission, “St. Lucie Unit 2 Docket No. 50-389, Proposed License Amendment, Request for Additional Information Response, WCAP-9272 Reload Methodology And Implementing 30 percent Steam Generator Tube Plugging Limit,” dated December 10, 2004.

9. Generic Letter 88-16, U.S. Nuclear Regulatory Commission Generic Commission, “Removal of Cycle Specific Parameter Limits from Technical Specifications,” dated October 4, 1988.

10. NUREG-1432, Revision 2, “Standard Technical Specifications - Combustion Engineering Plants,” dated June 2001.

11. CENPD-132, Supplement 4-P-A, “Calculative Methods for the CE Nuclear Power Large Break Evaluation Model,” dated March 2001.

12. CENPD-137, Supplement 2-P-A, “Calculative Methods for the ABB CE Small Break LOCA Evaluation Model,” dated April 1998.

13. CENPD-404-P-A, Revision 0, “Implementation of ZIRLO™ Cladding Material in CE Nuclear Power Fuel Assembly Designs,” dated November 2001.

14. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control/F_Q Surveillance Technical Specification,” dated February 1994.

15. WCAP-11397-P-A, “Revised Thermal Design Procedure,” dated April 1987.

16. WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Presurized Water Reactor Non-LOCA Safety Analyses,” dated April 1999.

17. WCAP-14565-P-A, “VIPRE-01 Modeling and Qualification for Pressurizer Water Reactor Non-LOCA Thermal Hydraulic Safety Analysis,” dated October 1999.

18. Letter from H. Berkow (NRC) to J. Gresham, Final Safety Evaluation for WCAP-14565-P-A, Addendum 1 and WCAP-15306-NP-A, Addendum 1, “Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code” (TAC No. MB9509), dated April 14, 2004.

19. WCAP-7588 Rev. 1-A, “An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetic Methods,” dated January 1975.

20. Letter from W. Jefferson, Jr. of Florida Power & Light to U.S. Nuclear Regulatory Commission, “St. Lucie Unit 2 Docket No. 50-389, Proposed License Amendment, Third Request for Additional Information Response, WCAP-9272 Reload Methodology And Implementing 30 percent Steam Generator Tube Plugging Limit,” dated January 7, 2005.

21. Letter to U.S. Nuclear Regulatory Commission, Document Control Desk from William Jefferson, Jr. (FPL) entitled, “St. Lucie Unit 2, Docket No. 50-389, Proposed License Amendments, Alternate Source Term and Conforming Amendments,” dated September 18, 2003.

22. Letter to U.S. Nuclear Regulatory Commission, Document Control Desk from William Jefferson, Jr. (FPL) entitled, “St. Lucie Unit 2, Docket No. 50-389, Supplemental Information, Alternate Source Term (AST) License Amendment,” dated January 7, 2005.

23. Numerical Applications Calculation Number, “NAI-1101-023, St. Lucie Unit 2 Steam Generator Tube Rupture Radiological Analysis with AST Methodology, Revision 2,” dated October 17, 2003.

24. Letter to U.S. Nuclear Regulatory Commission, Document Control Desk from J.A. Stall (FPL) entitled, “St. Lucie Units 1 and 2, Docket No. 50-335, 50-389, Seabrook Station, Docket No. 50-433, Generic Letter 2003-01, Supplemental Responses - Control Room Habitability (GL 2003-01),” dated October 29, 2004. ADAMS Accession Number ML040370441.

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TABLE 1

SGTR DBA ANALYSIS ASSUMPTIONS

Reactor power level, MWt (includes 2 % uncertainty)			2754
Initial RCS activity (1.0µCi/gm dose equivalent I-131)			Reference 21, Table 1.7.2-1
Initial secondary activity (0.1 µCi/gm dose equivalent I-131)			Reference 21, Table 1.7.3-1
Core fission product inventory			Reference 21, Table 1.7.4-1
Dose conversion factors			FGR 11 & 12
Offsite breathing rate, m^3/sec			
0-8 hours			3.5E-4
8-24 hours			1.8E-4
24-720 hours			2.3E-4
Control room volume, ft^3			97,600
Control Room HVAC system	Normal	Isolation	Filt. M/U
Time after accident, sec, hr	0-360 s	360 s-1.5 h	1.5 to 720 h
Filtered air makeup, cfm	0	0	450
Unfiltered air makeup, cfm	1000	0	0
Filtered recirculation, cfm	0	2000	1550
Unfiltered inleakage, cfm	1000	1000	1000
Intake filter efficiency,%			
Aerosols	99	99	99
Elemental/organic	99	99	99
Control room breathing rate, m^3/sec			3.5E-4
Control room occupancy factors			
0-24 hours			1.0
1-4 days			0.6
4-30 days			0.4
Control room χ/Q values			Table 2
Control Room Unfiltered inleakage due to ingress and egress after accident, cfm			10
Offsite χ/Q, sec/m^3			
EAB: 0-2 hr			Table 3
LPZ: 0-720 hr			

TABLE 1

SGTR DBA ANALYSIS ASSUMPTIONS (CONTINUED)

Pre-incident iodine spike activity (60 µCi/gm dose equivalent I-131)		Reference 7, Table 2.4-3
Coincident spike appearance rate, based on		Reference 7, Table 2.4-5
RCS letdown flow rate (120F, 2250 psia), gpm		150.0
RCS letdown demineralizer efficiency		4
RCS mass, lbm		452,000
RCS leakage, gpm		11
Coincident spike multiplier		335
Release duration, hrs		
Ruptured SG		8
Unaffected SGs		8
Liquid Masses, lbm		
RCS	475,385	(pre-incident spike)
RCS	452,000	(Coincident spike)
SG	105,000	(minimum)
SGTR integrated mass releases		Reference 7, Table 2.4-2
Break Flow Flash Fraction, %		
Pre-trip (up to 379.2 sec)		17.1 9
Post-trip		6. 6
Primary-to-secondary leakage		
Ruptured SG, gpm		.15
To three unaffected SGs, gpd		.15
Duration, hours		12
Chemical form release fractions		
Elemental		0.97
Organic		0.03
Steam partition coefficient in SGs		
Ruptured SG (flashed flow)		1.0
Ruptured (non-flashed flow)		100
Intact SG		100

Table 2

St. Lucie Unit 2 Control Room Relative Concentration (X/Q) Values
Steam Generator Tube Rupture Accident

TIME FRAME	RELEASE POINT	X/Q VALUES (sec/m^3)				
		0 TO 2 HOURS	2 TO 8 HOURS	8 TO 24 HOURS	1 TO 4 DAYS	4 TO 30 DAYS
Prior to CR Isolation	Condenser[3]	2.47×10^{-3}	-	-	-	-
	Closest MSSV/ADV[2]	6.69×10^{-3}	-	-	-	-
During CR Isolation	Condenser[2]	2.47×10^{-3}	-	-	-	-
	Closest MSSV/ADV[4]	3.11×10^{-3}	-	-	-	-
After Initiation of Filtered Make-up	Closest MSSV/ADV[5]	1.88×10^{-3}	1.46×10^{-3}	5.98×10^{-4}	4.23×10^{-4}	3.19×10^{-4}

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[3]The receptor is assumed to be the north CR intake.

[4]The receptor is assumed to be the midpoint between the CR intakes.

[5]The receptor is assumed to be the south CR intake.

Table 3

St. Lucie Unit 2 EAB and LPZ Relative Concentration (X/Q) Values
Steam Generator Tube Rupture Accident

TIME PERIOD	X/Q VALUES (sec/m^3)	
	EAB	LPZ
0-2 hours	1.10×10^{-4}	-
0-8 hours	-	5.91×10^{-5}
8-24 hours	-	4.41×10^{-5}
1-4 days	-	2.33×10^{-5}
4-30 days	-	9.32×10^{-6}