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SOUTHERN COMPANY
Energy to Serve Your World℠

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Vogtle Electric Generating Plant
Supplemental Information Supporting Acceptance Review,
Response to Request for Additional Information of November 20, 2007, and
Response to Request for Additional Information of November 29, 2007,
Regarding the Measurement Uncertainty Recapture Power Uprate Amendment

Ladies and Gentlemen:

On August 28, 2007, Southern Nuclear Operating Company (SNC) submitted a request to change the Maximum Power Level in paragraph 2.C(1) of the Vogtle Electric Generating Plant (VEGP) Facility Operating Licenses NPF-68 and NPF-81 for Unit 1 and Unit 2, respectively (NL-07-1020). SNC proposed to increase the licensed maximum power level by 1.7% by performing a measurement uncertainty recapture power uprate (MURPU).

During the acceptance review of the submittal, SNC was requested to provide further clarification of the plant design changes and the basis for implementation of the design changes in accordance with the provisions of 10 CFR 50.59 without requiring prior NRC approval. Enclosure 1 provides the subject clarification and bases.

By letters dated November 20, 2007, and November 29, 2007, the NRC requested additional information regarding the proposed amendment request. The request for additional information (RAI) included a series of questions from several branches within the NRC. Enclosure 2 provides the SNC response to the NRC RAI dated November 20, 2007, and Enclosure 3 provides the SNC response to the NRC RAI dated November 29, 2007.

(Affirmation and signature are provided on the following page.)

Mr. L. M. Stinson states he is a Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

This letter contains no NRC commitments. If you have any questions, please advise.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

L. M. Stinson
Vice President Fleet Operations Support

Sworn to and subscribed before me this 21st *day of* December*, 2007.*

Notary Public

My commission expires: July 5, 2010

LMS/DRG/daj

Enclosures: 1. Clarification of the Plant Design Changes and the Basis for Implementation
2. SNC Response to the November 20, 2007, NRC RAI Questions
3. SNC Response to the November 29, 2007, NRC RAI Questions

cc: Southern Nuclear Operating Company
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U. S. Nuclear Regulatory Commission
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Mr. S. P. Lingam, NRR Project Manager – Vogtle
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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Mr. N. Holcomb, Commissioner – Department of Natural Resources

Vogtle Electric Generating Plant
Supplemental Information Supporting Acceptance Review,
Response to Request for Additional Information of November 20, 2007, and
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Amendment

Enclosure 1

Clarification of the Plant Design Changes and the Basis for Implementation

Enclosure 1

On August 28, 2007, Southern Nuclear Operating Company (SNC) submitted a request to change the licensed maximum power level for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. SNC proposed to increase the licensed maximum power level by 1.7% by performing a measurement uncertainty recapture power uprate (MURPU). On pages 7 and 8 of Enclosure 1 of the August submittal, SNC described plant design changes that will be implemented to support operation at the uprated power level. The plant design changes are:

1. Installation of the Caldon Check-Plus leading edge flow meter (LEFM),
2. Replacement of the high pressure turbine,
3. Replacement of the heater drain pumps and motors,
4. Replacement of the steam generator steam pressure transmitters, and
5. Performance improvement of the steam dump valves.

<u>Caldon Check-Plus Leading Edge Flow Meter</u>

As discussed on page 7 of Enclosure 1 of the August submittal, the reduced uncertainty in the measured feedwater flow rate based on the LEFM provides the margin for the proposed power uprate. The approval sought by SNC is for operation at the proposed uprated maximum power level of 3625.6 MWt utilizing recaptured margin as a result of the reduced uncertainty in the measured feedwater flow rate. The LEFM will be installed in both units under 10 CFR 50.59. The LEFM can be utilized for providing the feedwater flow input to the calorimetric power calculation for operation at the current licensed maximum power level of 3565 MWt.

<u>High Pressure Turbine</u>

As discussed on page 7 of Enclosure 1 of the August submittal, the non-safety-related high pressure turbine (HPT) rotors will be replaced in both units. The HPT rotor replacement is necessary to accommodate the additional steam flow due to the power uprate. The rotors will be installed in the existing turbine shells. There are no changes being made to the turbine protection system. SNC is not requesting approval from the NRC to make the turbine modifications. The HPT rotors will be installed in both units under 10 CFR 50.59. The replacement HPT rotors can be utilized for operation at the current licensed maximum power level of 3565 MWt.

<u>Heater Drain Pumps and Motors</u>

As discussed on page 7 of Enclosure 1 of the August submittal, the heater drain system pumping capability is marginal. Though the pumps and motors can perform their function at the MUR power uprate conditions, SNC plans to replace the pumps and motors to improve system performance at these conditions. SNC is not requesting approval from the NRC to make the heater drain system modifications. The heater drain pumps and motors will be installed in both units under 10 CFR 50.59. The replacement heater drain pumps and motors can be utilized for operation at the current licensed maximum power level of 3565 MWt.

Steam Generator Steam Pressure Transmitters

As discussed on page 7 of Enclosure 1 of the August submittal, SNC has been conducting an ongoing program to replace the steam generator pressure transmitters. The replacement of these transmitters has been completed on both units. The replacement steam generator pressure transmitters were installed in both units under 10 CFR 50.59. The discussion on page 7 of Enclosure 1 of the submittal noted that the LEFM-based calorimetric uncertainty analyses were based on the implementation of the replacement steam generator pressure transmitters. The replacement steam generator pressure transmitters are being utilized for operation at the current licensed maximum power level of 3565 MWt.

Performance Improvement of the Steam Dump Valves

As discussed on pages 7 and 8 of Enclosure 1 of the August submittal, SNC has been conducting an ongoing program to improve the performance of the steam dump valves to ensure that the valve stroke and trip-open time are consistent with that assumed in the applicable analyses. This is applicable to the current analyses as well as the MUR power uprate analyses. SNC is not requesting approval from the NRC to make the steam dump modifications. The modifications in both units will be made under 10 CFR 50.59. Some of the modifications on both units will be made prior to the upcoming refueling outages in which the power uprates will be implemented. The remaining modifications will be completed during the 2008 outages.

Vogtle Electric Generating Plant
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Enclosure 2

SNC Response to the November 20, 2007, NRC RAI Questions

Enclosure 2

<u>Instrumentations and Controls Branch</u>

<u>Question 1</u>

Criterion 3 in NRC Staff SE on the Caldon Topical Reports ER-80P and ER-157P requested licensees to confirm that the methodology used to calculate UFM uncertainty is based on accepted plant setpoint methodology. Usage of an alternative should be justified and applied to both the venturi and UFM for comparison.

SNC's response in enclosure 5 neither confirmed that the methodology used is based on NRC staff accepted plant setpoint methodology (SE reference should be provided) nor justified using an alternate methodology applying to both instruments for comparison.

<u>Response 1:</u>

The basis for the VEGP RTS and ESFAS setpoint methodology is WCAP-11269, Revision 1, "Westinghouse Setpoint Methodology for Protection Systems - Vogtle Station," November 1986. This was used for the setpoints for the initial licensing of VEGP and is referenced in Technical Specification Bases B3.3.1 and B3.3.2. An alternate methodology for calculation of UFM uncertainty was not used.

The fundamental approach used in the setpoint methodology is to statistically combine the inputs to determine the overall uncertainty. Channel Statistical Allowances (CSA) are calculated for the instrument channels. Dependent parameters are arithmetically combined to form statistically independent groups which are then combined using the Square Root of the Sum of Squares (SRSS) approach to determine the overall uncertainty. As described in Enclosure 5, Section I, Item D, the same fundamental approach was used to determine the UFM-based power calorimetric uncertainty. This approach has been approved by the NRC in the above-referenced Caldon Topical Reports ER-80P and ER-157P as well as recently for Seabrook Station Unit 1 (Amendment 110 of Facility Operating License NPF-86, May 22, 2006).

Question 2

Section G in enclosure 5 provides justification for the proposed 48 hours Allowed Outage time (AOT). It is stated in the first bullet that the alternate instrumentation accuracy could degrade over time as a result of nozzle fouling or transmitter drift, but this degradation will not result in significant uncertainty associated with the calorimetric measurement over a 48-hour period. Is this a qualitative statement or is there transmitter drift data for this conclusion. Provide the calculated effect of the known transmitter drift on the power calorimetric calculation during the AOT.

Response 2:

Fouling of the venturi nozzles results in a higher than actual indication of feedwater flow. This condition results in an overestimate of the calculated calorimetric power level which is conservative because the reactors will actually be operating below the calculated power level. The statement concerning transmitter drift was qualitative but actual drift data for the feedwater venturi transmitters has subsequently been reviewed. The drift data shows the worst case drift for any one transmitter (eight transmitters installed per Unit with two installed on each of the four loops) to be on the order of 0.5 % over the 18 month calibration interval. Even conservatively assuming all transmitters drifted by this magnitude in the same direction, the impact on the thermal power measurement over the 48 hour AOT has been calculated to be less than 0.1 MWt. (This assumes a linear behavior of drift over the 18 month interval). Also, based on the calculated average drift value for all feedwater transmitters over the 18 month interval, the impact on the thermal power measurement over the AOT would be undetectable.

Question 3

Provide confirmation that the UFM mass flow uncertainty used in the total thermal power uncertainty determination includes uncertainty for the actual location of the transducers within the housing as identified in Cameron Customer Information Bulletin CIB 125, Rev.0 dated April 23, 2007.

Response 3:

A transducer can be located in any of the sixteen (16) locations on a spool. The uncertainty for transducer installation, as identified in Cameron Customer Information Bulletin CIB 125, Rev.0 dated April 23, 2007, has been included in the LEFM CHECK PLUS system Uncertainty for Vogtle Unit 1 (ER477R5) and Vogtle Unit 2 (ER586R1). These system uncertainties incorporate an additional transducer variability uncertainty in both the profile factor uncertainty and in the installation uncertainty.

Question 4

Section 7.11.2.5 in WCAP-16736 indicates that P-9 setpoint and the associated allowable values (AV) are changed to lower values to accommodate non availability of pressurizer spray flow, three steam dump valves out-of-service, and manual rod control conditions. Confirm that the current setpoint and AV value of P-8 will not need adjustment to reflect P-9 changes. Current TS P-9 setpoint and AV are higher than the P-8 values. The proposed change will reverse the difference.

Response 4:

The functions of P-8 and P-9 are unrelated. The function of the P-8 permissive is to ensure that a reactor trip will occur due to a loss of flow in any reactor coolant flow loop when operating above the P-8 setpoint. Below this setpoint, a loss of flow in two or more loops is required to cause a reactor trip. This trip function precludes a departure from nucleate boiling (DNB) condition from occurring in the core.

The function of the P-9 setpoint is to ensure that a reactor trip will occur due to a turbine trip when operating above the P-9 setpoint. Below this setpoint, a turbine trip will not result in a reactor trip. The value of the P-9 setpoint is chosen such that a reactor trip that occurs when the power level is above the P-9 setpoint precludes the pressurizer power-operated reliefs valves (PORVs) from opening following a turbine trip. Below the P-9 setpoint, the PORVs will not open upon a turbine trip without a reactor trip.

Question 5

To support NRC assessment of the acceptability of the LAR in regard to the setpoint change, SNC is requested to provide the following:

A. Provide documentation of the methodology used for establishing the limiting setpoint (or NSP) and the limiting acceptable values for the As-Found and As-Left setpoints as measured in periodic surveillance testing. Indicate the related Analytical Limits and other limiting design values (and the sources of these values).

Response 5A:

The revised P-9 setpoint of 40 percent was determined based on a best estimate analysis using the LOFTRAN code approved by the NRC in WCAP-7907-P-A, "LOFTRAN Code Description," April 1984. The P-9 analysis is discussed in Section 7.11.2 of WCAP-16736.

The Allowable Value was determined consistent with the Allowable Values for OTDT and OPDT approved by the NRC in Vogtle Unit 1 and 2 Amendments 128 and 106 respectively issued June 4, 2003.

In addition, the VEGP TS contains the following note applied to each Nominal Trip Setpoint (NTS): "A channel is OPERABLE with an actual Trip Setpoint value outside its calibration tolerance band provide the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is readjusted to within the established calibration tolerance band of the Nominal Trip Setpoint." The addition of this Note was approved by the NRC with Amendments 101 and 79 to the Unit 1 and Unit 2 TS, respectively.

B. Provide a statement as to whether or not the P-9 setpoint is a limiting safety system setting on which a safety limit (SL) has been placed as discussed in 10 CFR 50.36(c)(1)(ii)(A). If the P-9 setpoint is not SL-Related, explain the basis for this.

Response 5B:

The P-9 setpoint does not protect a reactor core safety limit or a reactor coolant system pressure safety limit. The basis for this is discussed in Enclosure 1, pages 4 and 5, of the License Amendment Request dated August 28, 2007.

C. If the P-9 setpoint is determined to be SL-Related, please refer to the NRC letter to the NEI SMTF dated September 7, 2005 (ML052500004) which describes Setpoint-Related TS (SRTS) that are acceptable to the NRC for instrument settings associated with SL-Related setpoints. Specifically: Part "A" of the Enclosure to the letter provides LCO notes to be added to the TS, and Part "B" includes a check list of the information to be provided in the TS Bases related to the proposed TS change.

   1. Describe whether and how the SRTS suggested in the September 7 letter will be implemented. If you do not plan to adopt the suggested SRTS is adopted, then explain how compliance with 10 CFR 50.36 will be assured by addressing items C2 and C3, below.

   2. Describe how surveillance test results and associated TS limits are used to establish operability of the safety system. Show that this evaluation is consistent with the assumptions and results of the setpoint calculation methodology. Discuss the plant corrective action processes (including plant procedures) for restoring channels to operable status when channels are determined to be "inoperable" or "operable but degraded." If the criteria for determining operability of the instrument being tested are located in a document other than the TS (e.g. plant test procedure) explain how the requirements of 10 CFR 50.36 are met.

   3. Describe the controls employed to ensure that the instrument setpoint is, upon completion of surveillance testing, consistent with the assumptions of the associated analyses. If the controls are located in a document other than the TS (e.g. plant test procedure) explain how the requirements of 10 CFR 50.36 are met.

Response 5C:

Based on the response to Question 5B above, Question 5C is not applicable to the change to the P-9 setpoint.

D. For setpoints that are determined to be non-SL-related, describe the measures to be taken to ensure that the associated instrument channel is capable of performing its specified safety functions in accordance with applicable design requirements and associated analyses. Include in your discussion information on the controls you employ to ensure that the as left trip setting after completion of periodic surveillance is consistent with your setpoint methodology. Also, discuss the plant corrective action processes (including plant procedures) for restoring channels to operable status when channels are determined to be "inoperable" or "operable but degraded." If the controls are located in a document other than the TS (e.g., plant test procedure), describe how it is ensured that the controls will be implemented.

Response 5D:

This is discussed in Enclosure 1, pages 4 and 5, of the License Amendment Request dated August 28, 2007.

<u>Technical Specifications Branch</u>

<u>Question 1</u>

Demonstrate compliance with 10 CFR 50.36(c)(2) and (c)(3) for plant operating conditions when the Caldon Check-Plus ultrasonic feedwater flow element cannot perform its specified support function in performing the calorimetric heat balance.

The LAR revises the Rated Thermal Power (RTP) MWt limit in technical specifications (TS) Section 1.1, Definitions. Additionally, the changes include revising the Power Range Neutron Flux, P-9 Interlock Nominal Trip Setpoint and Allowable Value setpoint related to operating at 3625.6 MWt. Regulation 10 CFR 50.36(c)(2) specifies when a LCO is not met, the plant must be shutdown or follow any remedial action specified by the TS. Regulation 10 CFR 50.36(c)(3) specifies that surveillance requirements assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits and that the limiting conditions for operation will be met. The proposed LAR TS changes do not specify TS required actions that must be followed if the Caldon Check-Plus ultrasonic feedwater flow element inputs to the calorimetric heat balance are not available for meeting surveillance requirements to demonstrate the LCO is met.

Further, RIS 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications, Attachment 2, Evaluation of Feedback Received During the Public Workshop on August 23, 2001 (Arranged by Guidance Section), provides the following guidance:

I.5. What should a licensee do when the instrument is out of service?

NRC staff approvals of topical reports for the feedwater measurement technique identify what information is appropriate for addressing this comment (typically included as the first criterion). Therefore, this information is covered by Items I.1.C. and I.1.D. of the draft guidance. However, as a result of this comment, the NRC staff has modified Section I. to provide more explicit guidance in this area. Specifically, a licensee should propose an allowed outage time for the instrument, similar to the allowed outage times contained in the technical specifications for other equipment. If an approved allowed outage time is exceeded, the licensee should reduce the power level of the plant to ensure that it appropriately accounts for the uncertainty in the instrumentation being relied upon.

Item I.1.G. and H. of the guidance now address the NRC staff's information needs for this case. (Emphasis added)

Therefore, the licensee must describe what TS(s) should be created or modified to address the requirements of 10 CFR 50.36(c)(2), including Required Actions and Completion Times, or state why no additional changes are needed for the TS when the Caldon Check-Plus ultrasonic feedwater flow element inputs are not available for the heat balance calorimetric algorithm.

<u>Response 1:</u>

Item I.5 of Attachment 2 of RIS 2002-03 referenced above describes the resolution to the feedback received during the public workshop on August 23, 2001. With regards to allowed outage times (AOT) and proposed actions, Item I.5 states that Items I.1.G and H of the guidance (RIS 2002-03) now address the Staff's information needs.

Accordingly, SNC addressed the AOT and proposed actions in a manner consistent with Items I.1.G and H of RIS 2002-03. The guidance in RIS 2002-03 does not suggest that any Technical Specification be created or modified to address the condition of the Caldon Check-Plus ultrasonic feedwater flow element inputs not being available for the heat balance calorimetric algorithm. The current VEGP Technical Specifications do not include any such provision for when the venturi flow element inputs are not available for the heat balance calorimetric algorithm. Likewise, there is no such provision in NUREG-1431, "Standard Technical Specifications Westinghouse Plants."

In the License Amendment Request (LAR) Seabrook submitted for Seabrook Station Unit 1, there was no proposed Technical Specification, or modification to a Technical Specification, to address the unavailability of the Caldon Check-Plus ultrasonic feedwater flow element inputs. In their LAR, as acknowledged on page 5 of the NRC's safety evaluation report for Seabrook Station Unit 1 (Amendment 110 of Facility Operating License NPF-86, May 22, 2006), they stated that they will modify their plant procedures. Similarly, SNC will modify applicable licensee-controlled documents to provide operational guidance to address the condition of the Caldon Check-Plus ultrasonic feedwater flow element inputs not being available for the heat balance calorimetric algorithm, as well as actions to be taken if these inputs are not restored within the AOT.

The functional requirements for the Caldon Check-Plus ultrasonic feedwater flow element inputs to the heat balance calorimetric algorithm do not meet the criteria of 10 CFR 50.36(c)(2)(ii) for establishing a Technical Specification (TS) Limiting Condition for Operation (LCO). Each criterion is addressed as follows:

<u>Criterion 1</u>

The Caldon Check-Plus ultrasonic feedwater flow element inputs are not used to detect and indicate abnormal degradation of the reactor coolant pressure boundary.

<u>Criterion 2</u>

The Caldon Check-Plus ultrasonic feedwater flow element inputs are not initial conditions of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

<u>Criterion 3</u>

The Caldon Check-Plus ultrasonic feedwater flow element inputs are not part of the primary success path and do not function or actuate to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

<u>Criterion 4</u>

In the event of the Caldon Check-Plus ultrasonic feedwater flow element inputs not being available for the heat balance calorimetric algorithm, the inputs will be determined by alternate instrumentation thus, the Caldon Check-Plus ultrasonic feedwater flow element inputs are not significant to public health and safety.

It is therefore concluded that an LCO is not required to be included in the TS in accordance with 10CFR50.36(c)(2)(ii) to address the functional requirements for the Caldon Check-Plus ultrasonic feedwater flow element inputs to the heat balance calorimetric algorithm.

Operator Licensing and Human Performance Branch

Question 1

Operator Actions (RIS 2002-03 Section VII.1)

a. Has the licensee identified any additional design bases events that will require any revisions to existing operator manual actions or available times?

Response 1.a:

Beyond the design bases events that have already been reviewed per Enclosure V, Section VI, Item 1 in the August 28, 2007 submittal, there are no additional design basis events that that will require any revisions to existing manual actions or available times.

Question 2

Emergency and Abnormal Operating Procedures (RIS 2002-03 Section VII.2.A)

a. What will be revised in VEGP emergency operating procedures (EOPs) and abnormal operating procedures (AOPs) to accommodate the MUR power uprate? How will the operators be made aware of these changes?

Response 2.a:

A number of revisions will be required for the EOP and AOP procedures due to setpoints needing change due to the MURPU power conditions or increase in decay heat at shutdown conditions. These are setpoint changes only and will not impact any required operator actions. Procedures which reference the current license power level (MWt) will also need revision to reflect the MURPU licensed power level. As described in Enclosure V, Section VI, Item 2D in the August 28, 2007 submittal, operators will be made aware of the changes as part of the formal process for operator training and requalification prior to implementation of the MURPU.

Question 3

Control Room Controls, Displays (Including the Safety Parameter Display System), and Alarms (RIS 2002-03 Section VII.2.B)

a. How will the installation of the new Caldon Leading Edge Flowmeter (LEFM) annunicator and associated computer display modifications impact the operators' ability to operate both Units after implementation of the MUR power uprate? How will the operators diagnose and address functionality errors of the Caldon LEFM system?

Response 3.a:

A Caldon LEFM system will be installed for each Unit with its own unique local electronics cabinet, control room computer display, and main control board annunciator alarm. No LEFM components, displays, or annunciators are shared between the two Units, therefore, the annunciator and display modifications will not impact the operators' ability to operate both Units.

As described in Enclosure V, Section 1, p. 4 of 13 in the August 28, 2007 submittal, the control room annunciator alarm will alert the operators to conditions that indicate functional errors of the Caldon LEFM system. An annunciator response procedure (ARP) will give the operators direction for alarm diagnosis via use of the control room display or the local cabinet display.

Question 4

Control Room Plant Reference Simulator and Operator Training Program (RIS 2002-03 Section VII.2.C and D)

a. Has the licensee identified any additional changes to the plant simulator to address the effects of the MUR power uprate?

Response 4.a:

Beyond the plant simulator modifications identified in Enclosure V, Section VII, Item 2.C, no additional changes to the plant simulator will be required to address the effects of the MURPU.

b. What other aspects of the MUR power uprate will be incorporated by the licensee's design change process in order to ensure that operators will be made aware of all plant modifications prior to implementation of the MUR power uprate?

Response 4.b:

Beyond the aspects of the MURPU identified in Enclosure V, Section VII, Item 2.D, no other aspects of the MURPU will be incorporated by the design change process to ensure that the operators will be made aware of all plant modifications prior to MURPU implementation.

Electrical Engineering Branch

Question 1

In Section V, Part D of the license amendment request, the licensee states that the stability impact of the power uprate was evaluated and concludes that the proposed electrical output uprate for the units will not cause any stability problems. Provide the grid stability study and discuss in depth the assumptions, methodology, cases studied, and evidence to support the conclusion.

Response 1:

The following report documents the transient stability analysis of the Southern Electric System with the proposed MW uprate for Vogtle units #1 and #2. This stability review was done with two dynamic ready cases, one with a valley case load level (17GW) and one with 50% load level (23.3GW).

The results show that with the proposed MW uprate for the Vogtle units, the critical breaker failure clearing time (BFCT) for the studied contingencies would be reduced by some degree, a reduction as much as 3.75 cycles from what was obtained with the existing MW outputs from Vogtle units. However, the current actual clearing time (CT) settings are much lower than the critical clearing time (CCT) obtained in the study. Therefore, the proposed MW uprate for Vogtle units will not cause any stability problems.

Scope of Study

A 2006 Valley case was created for this study. Also a 50% load level case was used. Two scenarios were studied as listed in Table 1.

Table 1: Proposed and Existing Gross MW Outputs of units.

Scenarios	Vogtle #1 MW	Vogtle #2 MW
Proposed	1280	1280
Existing	1215	1215

The breakers at Vogtle 500 kV and 230 kV substations are two (2) cycle IPO breakers. The single-line diagram for Vogtle 500/230 kV is shown in Figure 1.

Enclosure 2

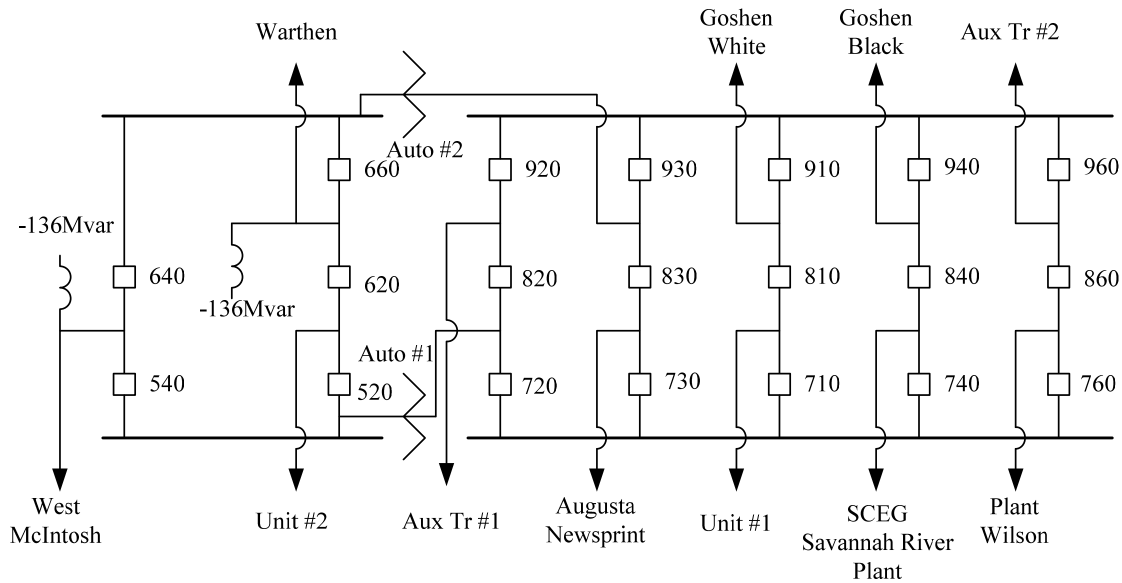

Fig. 1. Single-line diagram of Vogtle 500/230 kV.

<u>Assumptions</u>

The following assumptions were made in this study:

1. The load flow base cases used in this study represent both 50% (of peak) load level and valley load conditions. The light load conditions usually present the worst results for angular stability.
2. All 500 kV circuit breakers at Plant Vogtle are two-cycle breakers with independent pole operation (IPO) capability
3. All 230 kV circuit breakers at Plant Vogtle are two-cycle breakers with independent pole operation (IPO) capability
4. Plant Vogtle 500 kV switchyard is a ring bus design. Plant Vogtle 230 kV switchyard is a breaker-and-a-half design.
5. The (maximum) installed breaker failure clearing time for all 230 and 500 kV breakers at Plant Vogtle is 9.25 cycles.
6. The station service load for Plant Vogtle Units 1 and 2 are 60.6+j30.4 MVA and 61.5+j30.5 MVA, respectively, at the generator terminals. In addition, 9+j4.4 MVA and 9+j4.5 MVA for Units 1 and 2, respectively, are modeled at Vogtle 230 kV bus.

<u>Analyses and Results</u>

The specific fault events and subsequent network protection system switching actions are detailed as follows for the simulations made.

Plant Vogtle 230 kV Faults with Normal Clearing

NC_1: Close-in fault on Goshen (white) 230 kV line
- a) Trip Vogtle 810 and 910 in CCT
- b) Trip Goshen (white) end in CCT+2c (Pilot Relay w./3c breakers @ Goshen)

NC_2: Close-in fault on Augusta Newsprint 230 kV line
- a) Trip Vogtle 730 and 830 in CCT
- b) Trip Augusta Newsprint end in CCT+1c (Pilot Relay)

NC_3: Close-in fault on SCEG 230 kV line
- a) Trip Vogtle 740 and 840 in CCT
- b) Trip SCEG 230 kV line end in CCT+1c (PR)

NC_4: Fault on 230 kV side of autobank #2
- a) Trip Vogtle 830, 930, 640 and 660 in CCT

Plant Vogtle 500 kV Faults with Normal Clearing

NC_5: Close-in fault on Warthen 500 kV line
- a) Trip Vogtle 620 and 660 in CCT
- b) Trip Warthen end in CCT+1c (PR)

NC_6: Close-in fault on West McIntosh 500 kV line
- a) Trip Vogtle 540 and 640 in CCT
- b) Trip West McIntosh end in CCT+1c (PR)

NC_7: Fault on 500 kV side of auto #2
- a) Trip Vogtle 640, 660, 830 and 930 in CCT

Plant Vogtle 230 kV Faults with Breaker Failure(BF)

BF_1: Fault on 230 kV side of autobank #2 fault w./ BF on 830

- a) Trip Vogtle 640,660, 930, and 830 (2 poles) in 3.5c (fault is now SLG)
- b) Trip Vogtle 730 in BFCT
- c) Trip Augusta Newsprint end in BFCT+1c (Transfer Trip)

BF_2: Close-in fault on SCEG 230 kV line w./ BF on 840

- a) Trip Vogtle 740 (SCEG) and 840 (2 poles) in 3c (fault is now SLG)
- b) Trip SCEG-Savannah River end in 4c (PR)
- c) Trip Vogtle 940 in BFCT
- d) Trip Goshen (black) end in BFCT+2c (TT w./ 3c breakers @ Goshen)

Plant Vogtle 500 kV Faults with Breaker Failure

BF_3: Fault on 500 kV side of Autobank #1 fault w./ BF 540

a) Trip Vogtle 520, 720, 820 and 540 (2 poles) in 3.5c (fault is now SLG)
b) Trip Vogtle 640 in BFCT
c) Trip West McIntosh end in BFCT+1c (TT)

BF_4: Fault on 500 kV side of Autobank #2 fault w./ BF 660

a) Trip Vogtle 640, 830, 930 and 660 (2 poles) in 3.5c (fault is now SLG)
b) Trip Vogtle 620 in BFCT
c) Trip Warthen end in BFCT+1c (TT)

A total of seven normal clear (NC) contingencies were evaluated (four on 230 kV and three on 500 kV). Only the worst two 230 kV breaker failure contingencies were evaluated at Plant Vogtle. Due to the arrangement of the existing switchgear (see Figure 1), the breaker failure contingencies involving breakers 830 and 840 will be the two worst-case scenarios due to the fact that both of these contingencies result in the loss of two power delivery components (lines and autotransformers). Breaker failure contingencies involving breakers 810, 820, or 860 would result in either only a single power delivery component being tripped or in the tripping of a unit. Such breaker failure contingencies are widely recognized as being inherently more stable.

Only two 500 kV breaker failure contingencies were evaluated at Plant Vogtle. In both cases, the fault was assumed to occur on the bus-work for the autotransformers because the transformer differential relaying is slightly slower than the zone 1 line relaying, thus producing the most severe contingencies from a transient stability point of view. Contingencies were selected such that Plant Vogtle Unit 2 was not tripped by the breaker failure relaying; the chosen contingencies would trip only power delivery equipment resulting in worst-case transient stability contingencies.

The simulation results (critical clearing time in cycles) for valley and 50% load level cases with the Proposed and Existing MW output scenarios were obtained and tabulated in Table 2.

Table 2: Critical clearing time (in cycles) comparison.

	Valley Load Level		50% Load Level		Actual Clearing Time
	Proposed MW	Existing MW	**Proposed MW**	Existing MW	
NC_1	**7.75**	8.5	**8.5**	9.25	3
NC_2	**8.25**	8.75	**8.75**	9.5	3
NC_3	**8**	8.75	**8.5**	9.25	3
NC_4	**8**	8.75	**8.75**	9.25	3.5
NC_5	**7.5**	8.25	**8**	8.75	3
NC_6	**7.5**	8.25	**8.25**	9	3
NC_7	**8.75**	9.5	**9.25**	10	3.5
BF_1	**14**	15.75	**15.5**	17.75	9.25
BF_2	**13**	14.75	**14.75**	16.75	9.25
BF_3	**17**	20.75	**20**	24.5	9.25
BF_4	**16.5**	20	**18.5**	22.5	9.25

Note: Proposed MW=1280MW, Existing MW=1215MW.

Appendix

Positive (Negative) sequence and Zero sequence impedances at Plant Vogtle

At Vogtle 230 kV Bus

	Pos. sequence Z	Zero sequence Z	PSS/E shunt fault Y
All in service	0.00028+j0.00581	0.00016+j0.00331	528-j10939
Without one auto	0.00032+j0.00646	0.00019+j0.00377	486-j9751
SCEG tie line open	0.00028+j0.00658	0.00015+j0.00339	432-j10011

At Vogtle 500 kV Bus

	Pos. sequence Z	Zero sequence Z	PSS/E shunt fault Y
All in service	0.00023+j0.00578	0.00016+j0.00393	413-j10282
Without one auto	0.00024+j0.00640	0.00018+j0.00466	343-j9029

Fire Protection Branch

Question 1

License amendment request, Section II, “Accidents and Transients for Which the Existing Analyses of Record Bound Plant Operation at the Proposed Uprated Power Level,” mentions safe-shutdown fire analysis. The results of the Appendix R evaluation for measurement uncertainty recapture (MUR) power uprate are provided in Table II-1. However this section does not discuss the time necessary for the repair of systems required to achieve and maintain cold shutdown nor the increase in decay heat generation following plant trips. The NRC staff requests the licensee to verify that, with the increased reactor power level of 3625.6 megawatts thermal, the safe-shutdown equipment for Vogtle Electric Generating Plant, Units 1 and 2, would remain in compliance with 10 CFR Part 50, Appendix R.

Response 1:

Per the Vogtle SSER 4, there are only two cold shutdown repairs that may be required. The first is a repair to the Unit 1 diesel fuel oil transfer pump. A control room fire may damage circuits for this pump which would prevent the emergency fuel oil day tank from being refilled. A repair is needed within 1.4 hours to provide a power source to this pump. The second repair involves installing portable ventilation equipment in the Train B ESF Chiller Room. A control room fire could damage the installed ventilation in the room. At least 48 hours are available to accomplish this repair. There are no changes in the Control Building heat load; therefore, the room heatup rate is not affected. These repairs are part of the original fire protection licensing bases. The aspects of these bases remain valid. The power uprate will not have any affect on these cold shutdown repairs.

The increase in decay heat generation due to the increased power level does not impact safe shutdown equipment. The safe shutdown analysis assumes safe shutdown is accomplished by only one train of equipment. Decay heat removal is still accomplished by only one train of AFW and RHR, for example. The systems necessary to achieve and maintain safe shutdown remain unchanged. Therefore, compliance is still maintained with the existing safe shutdown analysis. No new components that have not been previously analyzed are required for SSD in any fire area; therefore, there are no impacts.

Question 2

License amendment request, Section II, “Accidents and Transients for Which the Existing Analyses of Record Bound Plant Operation at the Proposed Uprated Power Level,” mentions safe-shutdown fire analysis. This section states that …”the MUR power uprate will increase the thermal and electrical power of the plant, therefore, adding heat to the plant areas. Overall temperature changes in the primary and secondary systems are very small [such that any] added heat load to the plant environment is not significant…” The NRC staff requests the licensee to provide the temperature changes in the primary and secondary systems. Further, the NRC staff requests the licensee to verify that additional heat in the plant environment from the MUR power uprate will not prevent required manual actions from being performed at their designated time.

Response 2:

Potential operator manual actions due to fires are outlined in procedure 17103A-C for fires in zones outside the Control Room and procedures 18038-1 and 18038-2 for fires inside the Control Room. The MUR power uprate does not create any adverse environmental conditions which would impact performance of these actions. Based on engineering evaluation, there are no significant environmental changes in plant areas due to the power uprate. There are no increases in heat load in various Control Building rooms (Control Room, Cable Spreading Room, Aux Relay rooms, computer rooms, HVAC area). There are no increases in heat load in the Auxiliary Building or Fuel Handling Building. There are no actions required to be performed inside Containment. There are potential manual operator actions performed in the MSIV and feedwater penetration areas. Temperatures in these areas do not increase significantly. Main steam temperature is reduced slightly (from 543.8 °F to 543.0 °F). Feedwater temperature increases slightly (from 446.3 °F to 448.2 °F). Main steam and feedwater piping is insulated, therefore, any room temperature changes are minimal. Operator access to these areas is unaffected. Radiation (gamma) levels may increase in the Auxiliary Building by 5%. This increase does not affect access into any areas that may be required for performance of safe shutdown manual actions. There are no environmental conditions that would affect the timing of the performance of these actions.

Question 3

The NRC staff notes that license amendment request, Section III, "Accidents and Transients for Which the Existing Analyses of Record do not Bound Plant Operation at the Proposed Uprated Power Level," does not include any discussion regarding changes to the fire protection program or other operating conditions that may adversely impact the post-fire safe shutdown capability in accordance with 10 *CFR Part 50*, Appendix R. Clarify whether this request involves changes to the fire protection program or other operating conditions that may adversely impact the post-fire safe-shutdown capability in accordance with 10 CFR Part 50, Appendix R. Provide the technical justification for whether and, if so, why, existing analyses do not bound any impact on accidents or transients resulting from any changes.

Response 3:

This request does not involve changes to the fire protection program. Changes to operating conditions as a result of the MUR power uprate have been evaluated and it was determined that those changes do not adversely impact the post-fire safe-shutdown capability of the plant. The following fire-event safe-shutdown plant systems were reviewed to determine if the MUR power uprate has any impact on post-fire safe-shutdown operator actions:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Main Steam System (MSS)
- Auxiliary Feedwater (AFW) System
- Residual Heat Removal (RHR) System
- Nuclear Service Cooling Water (NSCW) System
- Diesel Generator Fuel Oil Transfer System (Unit 1 only)
- Essential Safety Features Room Coolers

- Electrical Distribution System
- Containment Spray System (CSS)

The impact of fire-induced hot-shorts, open-circuits, and shorts-to-ground in the control room electrical circuitry on the ability to safely shut down the plant from outside the control room both, with and without offsite power available, was determined by a Control Room Fire Alternate Shutdown Evaluation (CRFASE). This evaluation defines fire-induced situations requiring special operating procedural requirements and identifies time constraints due to potential spurious control actions/inactions. The results of the CRFASE do not change as a result of the MUR power uprate since the power uprate does not create any new adverse conditions or significant changes to operating conditions that would impact the fire protection program or the performance of post-fire operator actions.

Potential operator manual actions due to fires are outlined in plant procedure 17103A-C for fires in zones outside the Control Room and procedures 18038-1 and 18038-2 for fires inside the Control Room. Operator access to the remote shutdown panel and other areas outside the control room remain accessible to facilitate post-fire safe shutdown manual operator actions. There are no changes in operating conditions that would affect the timing of the performance of these actions, change the safe-shutdown operator actions, or require any changes to the fire protection program.

The basis for determining any MUR power uprate impact on post-fire safe-shutdown operator actions is provided below. For the RCS, there are no changes in pressure and no changes in configuration due to the MUR power uprate; therefore, time constraints and compensatory measures related to potential RCS depressurization and loss of inventory, as a result of spurious opening of various pressurizer valves, are not affected by the MUR power uprate.

For the CVCS, there are no changes in configuration, setpoints, pressure, and flow rate as a result of the MUR power uprate. Hence, CVCS time constraints and compensatory measures related to potential pump failures, RCS inventory loss, and pressurizer overfill as a result of spurious closure, opening, and fire induced failure of various valves and instrumentation circuits are not affected by the MUR power uprate.

For the MSS, pressure and temperature will slightly decrease at MUR power uprate conditions. The MSS configuration is not changed for the MUR power uprate. MSS time constraints related to potential steam generator overfill and steam generator time to boil dry may change with the propensity for more rapid overcooling due to increased decay heat as a result of the MUR power uprate. MSS time constraints and compensatory measures related to atmospheric dump valves control are not changed by the MUR power uprate. The MSS compensatory measures to minimize the chances of a significant overcooling transient, as a result of steam generator overfill or boil dry, are to isolate (close) the MSIVs and MSIVs bypass, the MFIVs and MFIVs bypass, and the steam generator blowdown isolation valves. If upon arrival at the shutdown panel there is indication of uncontrolled flow into or out of any steam generator, compensatory measures consist of tripping various breakers to ensure closure of the MSIVs and MSIVs bypass, the MFIVs and MFIVs bypass, and the steam generator blowdown isolation valves. Although the MUR power uprate may change the times related to SG overfill or boil dry, the corresponding compensatory measures are not changed and therefore, there are no changes to operator actions.

For the AFW system, there are no changes in configuration, setpoints, pressure, and flow rate as a result of the MUR power uprate. The condensate storage volume of usable inventory required for MUR power uprate is bounded by the existing condensate storage tank useable inventory. Hence, AFW system time constraints and compensatory measures related to potential AFW actuation failure and spurious closure of a motor-driven AFW pump control valve are not affected by the MUR power uprate.

For the RHR system, cool down of the RCS to Mode 5 has been demonstrated to be within the existing design bases for the plant and there are no changes in configuration, pressure, and flow rate. Therefore, RHR system time constraints and compensatory measures related to potential pump failures, RCS and RWST loss of inventory, and RCS cooling control due to spurious closure of RHR pump suction and RHR heat exchanger outlet valves and opening of RHR vent and heat exchanger bypass valves are not affected by the MUR power uprate.

For the NSCW system, the Ultimate Heat Sink analysis was reanalyzed to demonstrate the ability of the NSCW System to provide cooling without normal makeup for thirty days following a postulated design basis LOCA with the reactor operating at MUR power uprate conditions, as a result of the analyses there are no changes in configuration, pressure, flow rate, and design temperature as a result of the MUR power uprate. Therefore, NSCW system time constraints and compensatory measures related to potential reduction in system flow rate due to fire induced spurious failures of NSCW return header temperature or pressure instruments are not affected by the MUR power uprate. For the Diesel Generator Fuel Oil Transfer system (Unit 1 only), the diesel generator fuel oil storage tank pump may not be available for automatic makeup due to a fire induced circuit failure. The diesel generator can run for approximately 1.4 hours with no automatic makeup assuming minimum level (level at which auto makeup should start) in the diesel generator fuel oil day tank. The compensatory measure for this failure is to perform the necessary repairs in the fuel oil storage tank pump electrical breaker cabinet to ensure a source of makeup to the fuel oil day tank for an operating diesel generator. The MUR power uprate does not impact the Diesel Generator Fuel Oil Transfer system time constraints or compensatory measures as there are no changes to tank setpoints, tank inventory, or system configuration as a result of the MUR power uprate.

For the Essential Safety Features Room Coolers, there are no changes in configuration as a result of the MUR power uprate. Also, the Control Building design heat load bounds any changes in temperature due to the MUR power uprate. Therefore, time constraints and compensatory measures related to potential loss of ventilation for the “B” train of the CBCR ESF chiller room due to spurious stopping of the room exhaust fan are not affected by the MUR power uprate. For the Electrical Distribution System, a control room fire may cause de-energizing of certain 480V switchgears resulting in loss of diesel generator building cooling due to spurious feeder breaker opening. The diesel generator room temperature can approach a point where proper equipment operation cannot be assured within 15 minutes following a diesel start with no cooling system operation. The compensatory measure for this failure is to place the appropriate control switches for the breaker in the local position and ensure that the breaker is closed following control room evacuation. The MUR power uprate does not change the configuration of the Electrical Distribution System for these switchgear units and therefore does not impact the time constraints and compensatory measures related to this fire induced failure.

For the CSS, there are no changes in configuration, setpoints, pressure, and flow rate as a result of the MUR power uprate. Hence, CSS time constraints and compensatory measures related to potential RWST inventory loss due to a fire induced spurious containment spray actuation signal are not affected by the MUR power uprate.

The changes associated with the MUR power uprate will not affect fire protection or safe shutdown systems. Fire area boundaries, including suppression and detection systems, doors, penetrations, walls, and barriers will not be impacted as a result of the MUR power uprate. There will be no modifications to existing structural steel members with fire resistant coatings, nor deletion or addition of any structural steel members. Communication systems required for fire event safe shutdown operator action in the event of a fire will not be altered or modified. The proper operation of fire protection features, such as detection and suppression systems will not be obstructed, altered, or hampered by the MUR power uprate. Safe shutdown systems and equipment will not be removed, altered, or modified as a result of the MUR power uprate and no new manual actions will be required to achieve compliance with the existing design basis. Raceways, circuits, and circuit protection, and emergency lighting will not be impacted by the MUR power uprate.

In conclusion, changes to operating conditions as a result of the MUR power uprate have been evaluated and it was determined that those changes do not adversely impact the post-fire safe-shutdown capability of the plant.

Vessels and Internal Integrity Branch

Question 1

In the Final Safety Analysis Reports Update, Revision 13, dated April 2006, under Section 5.3.1 "Reactor Vessel Materials," Table 5.3.1-8 and Table 5.3.1-9 "Reactor Vessel Material Surveillance Program Withdrawal Schedule" for VEGP, Units 1 and 2, respectively, the capsule withdrawal time is listed as effected full power years (EFPY) from plant start up. Please provide the dates and refueling outages numbers that correspond with the EFPY listed in Table 5.3.1-8 and Table 5.3.1-9 for VEGP, Units 1 and 2.

Response 1:

The following Tables provide the dates and refueling outage numbers that correspond with the EFPY listed in Table 5.3.1-8 and Table 5.3.1-9 for VEGP Units 1 and 2.

U1 Capsule Number	Withdrawal Time EFPY (FSAR)	Date Removed	Outage # for withdrawal
U	1.14	Fall 1988	1R1
Y	4.85	Spring 1993	1R4
V	8.78	Fall 1997	1R7
X	14.33	Fall 2003	1R11
W	Standby	Spring 2008 *	1R14
Z	Standby	Spring 2008 *	1R14

U2 Capsule Number	Withdrawal Time EFPY (FSAR)	Date Removed	Outage # for withdrawal
U	1.20	Fall 1990	2R1
Y	4.98	Spring 1995	2R4
X	7.78	Spring 1998	2R6
W	13.29	Spring 2004	2R10
Z	Standby	Fall 2008 *	2R13
V	Standby	Fall 2008 *	2R13

* Planned removal dates. Reference Letter NL-05-1323, dated July 28, 2005 where SNC notified the NRC of its plans for withdrawal of standby specimen capsules.

Question 2

In WCAP-16736-NP, Revision 1 dated May 2007, Section 8 "Other Evaluations," Sub-Section 8.1.1 "Introduction," Page 8-1, it was stated in the first paragraph: "In both cases, the analyses included plant specific evaluations for Cycles 1 through 11 and future projections were based on operation with low leakage fuel management and core power level of 3,565 MWt."

In the second paragraph it was stated: "... an analyses is discussed that uses the data from References 1 and 2 as a base and updates the future projections based on core power level of 3636 MWt with low leakage... "

Please clarify the above statements as they appear inconsistent with each other regarding the core power level used in determining the future fluence projections.

Response 2:

References 1 and 2 discussed in the question above provided the results of neutron fluence calculations completed in support of surveillance capsule analysis for the Vogtle Units 1 and 2 reactor vessels. These references are identified and discussed below.

1. WCAP-16278-NP, Revision 0, "Analysis of Capsule X from the Southern Nuclear Operating Company, Vogtle Unit 1 Reactor Vessel Radiation Surveillance Program," K. G. Knight, *et al.,* July 2004.

2. WCAP-16382-NP, Revision 0, "Analysis of Capsule W from the Southern Nuclear Operating Company, Vogtle Unit 2, Reactor Vessel Radiation Surveillance Program," T. J. Laubham, *et al*., July 2004.

The fluence analyses documented in these references included plant specific calculations for all fuel cycles completed at the time of the last capsule withdrawal. This encompassed fuel Cycles 1 through 11 for both units. For each reactor vessel, the calculations for fuel Cycles 1 through 11 were based on a core power level of 3565 MWt, which represented actual past operation and, therefore established a baseline fluence applicable to all fuel cycles completed at the time of the fluence analyses.

In the fluence evaluations described in References 1 and 2, projections for assumed future plant operations (beyond Cycle 11) were also listed. Since the Reference 1 and 2 calculations did not consider a plant uprate to 3636 MWt, the projections beyond the baseline end of Cycle (EOC) 11 actual fluence were also based on reactor operation at a core power level of 3565 MWt. Thus for the Reference 1 and 2 analyses, the projected fluence at any future time for continued operation at 3565 MWt can be expressed as:

$$\Phi_{3565}(t) = [\Phi_{3565}\,\Delta t] + \Phi_{EOC11} \qquad \text{(Equation 1)}$$

Where:

Φ_{3565} (t)	=	Projected neutron fluence at time t, based on a core power of 3565 MWt for the entire reactor operating period.
Φ_{3565}	=	The calculated neutron flux, based on a core power of 3565 MWt that is assumed for future operation beyond the end of Cycle 11 (EOC 11).
Δt	=	The time interval between the end of Cycle 11 and the time which the fluence projection is desired.
Φ_{EOC11}	=	The baseline EOC11 fluence that represents actual past operation (taken from References 1 and 2 for Units 1 and 2, respectively).

In the fluence evaluations completed for the VEGP MUR-PU submittal, a core power uprate of 3636 MWt was assumed to occur at the beginning of Cycle 12 for both units based on the uprate and the baseline neutron fluence values accrued from operation through EOC 11 at each unit remains as documented in Reference 1 and 2. However, the projections for future operation beginning at the beginning of Cycle 12 must be re-evaluated based on a power level of 3636 MWt rather than on 3565 MWt as was done in References 1 and 2.

Thus, for the VEGP MUR-PU submittal, the projected fluence at any future time considering an uprate to 3636 MWt, at the beginning of Cycle 12 can be expressed as:

$$\Phi_{Uprate}(t) = [\Phi_{3636}\,\Delta t] + \Phi_{EOC11} \qquad \text{(Equation 2)}$$

In the evaluation of the pressure vessel exposure applicable to the VEGP MUR-PU, the fluence levels accrued through the end of Cycle 11 (Φ_{EOC11}) from Reference 1 and 2 were used as the baseline fluence values representing actual past operation, and the incremental fluence accrued after the beginning of Cycle 12 was increased by the ratio of [3636]/[3565] providing an overall pressure vessel fluence based on operation at a core power level of 3565 MWt for fuel Cycles 1 through 11, followed by operation at a core power level of 3636 MWt for fuel Cycles 12 and beyond. This approach was applied to both Vogtle Units 1 and 2.

Question 3

Please provide a detailed discussion on the impact of the 1.7-percent MUR on the projected USE values for the RV beltline limiting plate materials, including plate identifications, based on USE data from surveillance capsules for both VEGP Units 1 and 2.

Response 3:

The impact on the USE is discussed on page 6-7 of WCAP-16736. The USE calculations for all beltline materials, including plate identification numbers, are identified in the following Tables:

Vogtle Unit 1 Predicted EOL (36 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	Surface EOL Fluence (10^{19} n/cm^2)	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Intermediate Shell Plate B8805-1	0.083	2.06	1.23	90	20	72
Intermediate Shell Plate B8805-2	0.083	2.06	1.23	100	20	80
Intermediate Shell Plate B8805-3[(a)]	0.062	2.06	1.23	107	9	97
Lower Shell Plate B8606-1	0.053	2.06	1.23	116	20	93
Lower Shell Plate B8606-2	0.057	2.06	1.23	113	20	90
Lower Shell Plate B8606-3	0.067	2.06	1.23	118	20	94
Intermediate Shell Longitudinal Weld Seams 101-124A, B & C[(a)]	0.042	2.06	1.23	134	3	130
Lower Shell Longitudinal Weld Seams 101-142A, B & C[(a)]	0.042	2.06	1.23	134	3	130
Intermediate to Lower Shell Circumferential Weld Seam 101-171[(a)]	0.042	2.06	1.23	134	3	130

Notes:
(a) Using Surveillance Capsule Data from WCAP-16278-NP.

Vogtle Unit 1 Predicted EOLR (57 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	Surface EOLR Fluence (10^{19} n/cm^2)	1/4T EOLR Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOLR USE (ft-lb)
Intermediate Shell Plate B8805-1	0.083	3.24	1.93	90	22	70
Intermediate Shell Plate B8805-2	0.083	3.24	1.93	100	22	78
Intermediate Shell Plate B8805-3[(a)]	0.062	3.24	1.93	107	10	96
Lower Shell Plate B8606-1	0.053	3.24	1.93	116	22	91
Lower Shell Plate B8606-2	0.057	3.24	1.93	113	22	88
Lower Shell Plate B8606-3	0.067	3.24	1.93	118	22	92
Intermediate Shell Longitudinal Weld Seams 101-124A, B & C[(a)]	0.042	3.24	1.93	134	3	130
Lower Shell Longitudinal Weld Seams 101-142A, B & C[(a)]	0.042	3.24	1.93	134	3	130
Intermediate to Lower Shell Circumferential Weld Seam 101-171[(a)]	0.042	3.24	1.93	134	3	130

Notes:

(a) Using Surveillance Capsule Data from WCAP-16278-NP.

Vogtle Unit 2 Predicted EOL (36 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	Surface EOL	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Intermediate Shell Plate R4-1	0.07	1.93	1.15	95	20	76
Intermediate Shell Plate R4-2	0.06	1.93	1.15	104	20	83
Intermediate Shell Plate R4-3	0.05	1.93	1.15	84	20	67
Lower Shell Plate B8825-1	0.06	1.93	1.15	83	20	66
Lower Shell Plate R8-1	0.07	1.93	1.15	87	20	70
Lower Shell Plate B8628-1[a]	0.05	1.93	1.15	85	7	79
Intermediate Shell Longitudinal Weld Seams 101-124A, B & C[a]	0.05	1.93	1.15	152	8	140
Lower Shell Longitudinal Weld Seams 101-142A, B & C[a]	0.05	1.93	1.15	152	8	140
Intermediate to Lower Shell Circumferential Weld Seam 101-171[a]	0.05	1.93	1.15	90	8	83

Notes:
(a) Using Surveillance Capsule Data from WCAP-16382-NP.

Enclosure 2

Vogtle Unit 2 Predicted EOLR (57 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	Surface EOLR	1/4T EOLR Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected EOLR USE (ft-lb)
Intermediate Shell Plate R4-1	0.07	3.06	1.82	95	22	74
Intermediate Shell Plate R4-2	0.06	3.06	1.82	104	22	81
Intermediate Shell Plate R4-3	0.05	3.06	1.82	84	22	66
Lower Shell Plate B8825-1	0.06	3.06	1.82	83	22	65
Lower Shell Plate R8-1	0.07	3.06	1.82	87	22	68
Lower Shell Plate B8628-1[a]	0.05	3.06	1.82	85	7	79
Intermediate Shell Longitudinal Weld Seams 101-124A, B & C[a]	0.05	3.06	1.82	152	8	140
Lower Shell Longitudinal Weld Seams 101-142A, B & C[a]	0.05	3.06	1.82	152	8	140
Intermediate to Lower Shell Circumferential Weld Seam 101-171[a]	0.05	3.06	1.82	90	8	83

Notes:
(a) Using Surveillance Capsule Data from WCAP-16382-NP.

Question 4

In Tables 6.1.2-1 and 6.1.2-2 of the MUR analysis report, it appears that the clad/metal neutron fluence values were used for calculations of ΔRT_{NDT}. ASME Code, Section XI, Appendix G, Article 2120 notes that a postulated flow to the 1/4T (Thickness) is to be used in determining facility pressure-temperature (P-T) limits. Therefore, neutron fluence values for the 1/4T depth should be used in lieu of fluence values located at the clad/metal interface for P-T limit determination. In the licensee's "Revision to the Pressure Temperature Report" dated July 1, 2005 (ML051870322), Table 5-5 notes that neutron fluence values located at 1/4T was used in calculating ΔRT_{NDT} values. Please clarify the differences between Table 6.1.2-1 and Table 6.1.2-2 of the MUR submittal and Table 5-5 of your July 1, 2005 report, and revise Tables 6.1.2-1 and 6.1.2-2, if necessary.

Response 4:

Tables 6.1.2-1 and 6.1.2-2 in WCAP-16736 are the ΔRT_{NDT} values that were used in the determination of the validity of the currently licensed surveillance withdrawal schedule and are unrelated to the applicability of the pressure-temperature limit curves. As discussed in the RAI above, Westinghouse concurs that the pressure temperature limit curves are based on the fluence values at the 1/4T depth, in lieu of the fluence values located at the clad/base metal interface. The applicability of the pressure-temperature limit curves is based on the change in fluence incurred due to the MUR-PU. The data contained in Tables 6.1.2-1 and 6.1.2-2 have no relationship to the data contained in Table 5-5, and therefore do not need to be revised.

Question 5

Please discuss the effects of the MUR on the integrity of ferritic Class 1 components, specifically the RV, steam generators, and pressurizer, in Section 6.3 of the MUR analysis report; e.g., provide the postulated flaw depth values and the ratio of the calculated stress intensity factor (K_I) to the reference fracture toughness (K_{IR}) for the ferritic components.

Response 5:

There are no specific changes to the reactor vessel equipment, key reactor vessel design inputs, or reactor vessel stress report results due to the MUR uprate.

There are no changes to the steam generator and pressurizer equipment or key design inputs resulting from the Vogtle MUR-PU. Key transients which minimize the bulk temperature of the steam generator/pressurizer pressure boundary are unaffected by the MUR-PU. Test transients (e.g., primary and secondary side hydrostatic tests and steam generator tube leakage tests) also a key input in the non-ductile fracture evaluation, are also not impacted. Therefore, with no changes to the design inputs, such as the key design transients, the MUR-PU has no effect on steam generator or pressurizer integrity. The calculated flaw depths and calculated stress intensity factors are not changed by the MUR-PU.

Question 6

Discuss the impact of the MUR on the VEGP, Units 1 and 2 reactor vessel PTS assessments in Section 6.1.2.3 *Description of Analyses/Evaluation Performed* for sub-paragraph *Pressurized Thermal Shock* of the MUR analysis report and how your conclusions regarding this issue relates to the values in Tables 6.1.2-1 through 6.1.2-7 of the report.

Response 6:

The MUR impacts the current fluence projections of VEPG Units 1 and 2, i.e., the MUR fluence projections exceed the current fluence projections. The Pressurized Thermal Shock reference temperature (RT_{PTS}) values are dependent on the fluence values; therefore RT_{PTS} calculations were performed using the MUR fluence projections for the reactor vessel beltline materials at EOL (36 Effective Full Power Years (EFPY)). The PTS calculations were performed using the latest requirements specified in the PTS Rule (10 CFR Part 50.61) for both 36 and 57 EFPY. Tables 6.1.2-4, 6.1.2-5, 6.1.2-6, and 6.1.2-7 in WCAP-16736 provide a summary of the limiting beltline material RT_{PTS} values. All RT_{PTS} values remain below the 10 CFR Part 50.61 screening criteria values using the projected MUR-PU fluence values for 36 and 57 EFPY for VEGP.

Tables 6.1.2-1 and 6.1.2-2 are provided to calculate the shift in RT_{NDT}, which is used to justify the continued applicability of the surveillance capsule withdrawal schedule. Table 6.1.2-3 is provided to show that VEGP Units 1 and 2 will remain in the same category for the Emergency Response Guideline Limits as discussed on page 6-7 of WCAP-16736.

Question 7

Discuss in detail the impact of the MUR on the structural integrity of the VEGP, Units 1 and 2 internal components in Section 6.2 *Reactor Internals* of the MUR; e.g., the effect of changes due to the MUR evaluations of the RV internals for loading due to structure deadweight, temperature differences, flow loads, fuel assembly pre-load, control rod assembly dynamic loads, vibratory loads, and earthquake accelerations. Identify the Code or Standard (including applicable edition) which was used in the structural evaluation of the VEGP, Units 1 and 2 internals.

Response 7:

The structural integrity of the VEGP Units 1 and 2 reactor internals design has been ensured by analyses performed on both a generic and plant-specific basis. These analyses were used as the basis for evaluating Vogtle Units 1 and 2 reactor internal components for the MUR-PU.

The criteria established by the 1974 Edition of the ASME Boiler and Pressure Vessel Code, Section III, Sub-section NG applies to these reactor internals analyses. However, it should be noted that Sub-section NG of the 1974 Edition of the ASME Code was not approved by the NRC for use at the time the VEGP Units 1 and 2 reactor internals were procured.

Since there were no changes in the NSSS design transients and fuel assembly design, and the impact due to seismic and LOCA loads is not changing from the current analysis of record due to the MUR-PU, the reactor internals components remain bounded by the current analysis of record. Therefore, the MUR-PU does not affect the RV internals for the loadings evaluated due to structure deadweight, temperature differences, flow loads, fuel assembly pre-load, control rod assembly dynamic loads, vibratory loads, and earthquake accelerations.

Based on these conclusions, the current analysis of record for the reactor internals components remains applicable for the Vogtle Units 1 and 2 MUR-PU.

Question 8

The RV internals of PWR-designed light-water reactors may be susceptible to the following aging effects:

(1.) cracking induced by thermal cycling (fatigue-induced cracking);
(2.) stress corrosion cracking (SCC);
(3.) irradiation-assisted stress corrosion cracking (IASCC)
(4.) loss of fracture toughness properties induced by radiation exposure for all stainless steel grades;
(5.) the synergistic effects of radiation exposure and thermal aging for cast austenitic stainless steel (CASS) grades;
(6.) stress relaxation in bolted, fastened, keyed; or pinned RV internal components induced by radiation exposure and/or exposure to elevated temperatures; and,
(7.) void swelling (induced by radiation exposure).

Table Matrix-1 of NRC Review Standard RS-001, Revision 0, “Review Standard for Extended Power Uprate,” provides the NRC staff’s basis for evaluating the potential for extended power uprates to induce these aging effects. In Table Matrix-1, the NRC staff states that guidance on the neutron irradiation-related threshold levels for inducing IASCC in RV internal components are given in WCAP-14577, Revision 1-A. However, the industry, through the Materials Reliability Program (MRP), is in the process of developing comprehensive inspection and evaluation guidelines for the management of PWR internals degradation due to all of the effects listed above.

In order to ensure that the functionality of the VEGP, Unit 1 and 2 RV internals is maintained over the remaining licensed life of the facility, the NRC staff requests that the licensee provide a commitment to follow and participate in the MRP’s development of these comprehensive guidelines. In addition, the NRC staff requests that the licensee commit to evaluating the applicability of these guidelines, upon their completion, to VEGP, Units 1 and 2 and implementing any recommended inspections/evaluations to manage the effect noted above.

Response 8:

SNC will participate in the industry program for investigating and managing aging effects on reactor vessel internals.

SNC will evaluate and implement the results of the industry programs, such as the EPRI Material Reliability Program (MRP), as applicable to the VEGP reactor vessel internals.

Accident Dose Branch

Question 1

Regulatory Guide (RG) 1.195, "Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents (DBA's) at Light-Water Nuclear Power Reactors" is the U. S. Nuclear Regulation Commission (NRC) guidance document for performing accident dose consequence re-analysis for light water reactor power plants that utilize the Technical Information Document (TID)-14844 source term methodology. In regulatory position 1.3.1, "Design Basis Radiological Analyses" of RG 1.195 states in principal that all the applicable dose consequence DBA's listed in the RG and the final safety analysis report (FSAR) need to be re-analyzed for control room (CR) dose consequence. This is done to identify the limiting event for the general design criterion (GDC)-19 CR dose design criterion.

Please verify that you performed this analysis for all dose consequence DBA's other than the loss-of-coolant accident (LOCA) and the fuel handling accident (FHA) with no containment isolation. List the accidents analyzed for CR dose consequences and the resulting accident dose values. Also provide the analysis methods and assumptions, including the values used for the CR atmospheric dispersion factor (χ/Q) for each accident.

Please confirm that the LOCA is the bounding CR dose DBA by presenting your analysis results above or by justifying that your change in analysis assumptions would not cause any other DBA to be limiting for the CR dose consequence.

Response 1:

Control room doses are calculated for the limiting accidents grouped by the control room emergency filtration system (CREFS) initiation signal. The CREFS is initiated by a safety injection signal (see UFSAR 6.4.3.2) for all accidents inside containment except fuel handling accident, or by the intake radiation monitor for accidents outside containment which do not generate a safety injection signal. Therefore, the control room dose analysis considers the most limiting combination of release magnitude and location from accidents inside the containment and those outside the containment.

For accidents outside the containment, the most limiting release (largest activity release and closest to the control room) is the fuel handling accident in the fuel handling building. The fuel handling accident in the containment without isolation is bounded by the fuel handling accident in the fuel handling building since the source terms and releases are equal and the fuel handling building X/Q bounds those for releases from the containment. For accidents inside the containment (except fuel handling accident) where the containment is isolated and CREFS is initiated by a safety injection signal, the largest release is for the LOCA.

Therefore, control room doses are calculated only for these two accidents. Inputs for these two analyses are discussed in the response to Question 8 and the enclosed UFSAR table excerpts. As shown in Table III-4 of Enclosure 5-Section III, the LOCA control room dose bounds the fuel handling control room dose recalculated in response to Question 9.

Question 2

The CR χ/Q values presented in Table III-2 of Enclosure 5 - Section III to Vogtle Electric Generating Plant (VEGP) Measurement Uncertainty Recapture (MUR) Power Uprate (PU) submittal represent Unit 2 containment hatch door releases to Unit 2 CR emergency air intakes (i.e., Output File: VGC2R2X.out) during a design-basis LOCA. These values are characterized as the most limiting χ/Q values for releases from each of the two VEGP Units (Unit 1 and Unit 2) to each of the CR emergency air intakes. However, χ/Q values presented on the enclosed compact disk with supplemental letter dated October 9, 2007 (ML072850108) shows more conservative atmospheric dispersion factors for the releases from the Unit 1 Fuel Handling Building (FHB) to the Unit 1 CR (i.e., Output File: VGC1FHB.out) at all time periods (0-720 hours).

Please verify that the estimated CR doses derived using the revised χ/Q values for the MUR power Up-rate presented in the submittal dated August 28, 2007 (ML072470691) bound the CR dose estimates derived using χ/Q values presented in the VGC1FHB.out file.

Response 2:

Fuel handling accident doses for the fuel handling accident, including control room doses, were recalculated using the X/Q value for the fuel handling building from VGC1FHB.out, the automatic control room intake radiation monitor isolation time (Question 9), and the input data as described in the response to Question 8. The results provided in the response to Question 9 meet GDC 19.

Question 3

Pursuant to NRC Regulatory Issue Summary (RIS) 2002-03: *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, a change in licensed power level requires that the radiological consequences of the accidents analyzed in the Chapter XV of the VEGP updated final safety analysis report (UFSAR) be reanalyzed due to increase in source terms. Accordingly, new χ/Q values were presented for the “limiting” LOCA DBA for releases to VEGP Units 1 and 2 CR (i.e., onsite). However, no offsite χ/Q values were presented. Please confirm that the χ/Q values for releases to the exclusion area boundary and outer boundary of the low-population zone are bound by the values currently listed in the VEGP Units 1 and 2 UFSARs. Please provide these calculations to confirm your determination.

Response 3:

Offsite doses were re-calculated for the change in source terms using the existing X/Q values currently shown in the VEGP UFSAR; offsite X/Q values were not re-calculated.

Question 4

In section 7.8.1, “Radiation Source Terms” of WCAP-16736-P, you have generally described the basis for the re-calculation of your reactor core source term. Describe in detail the analysis methods and the specific assumptions including the release fractions used for the reactor core source term recalculation. Describe in detail any deviations from the guidance in section 3.1 of RG 1.195.

Response 4:

The core source term currently discussed in the VEGP UFSAR is for the end of the fuel cycle and was calculated in 1978 using the 1973 version of the ORIGEN code and is based on a core power of 3565 MWt with a 12 month fuel cycle. The source term does not include any adjustment for power measurement uncertainty. The source term presented in WCAP-16736 is based on values that were calculated in 1990 using a later version of the ORIGEN code and addressed both an 18 month fuel cycle and extended fuel burnup. This analysis utilized more sophisticated modeling than was used in the earlier source term calculation. For the MUR-PU the values obtained in the 1990 analysis were subjected to the following adjustments:

- The nuclide inventories were increased by a factor of 1.02 to address the increase in licensed power from 3565 MWt to 3626 MWt (an increase of ~1.7%) plus the reduced calorimetric uncertainty of ~0.3%.
- The nuclide inventories were increased by a nominal amount to provide margin for ongoing fuel cycle design variations. The increases were 15 percent for Kr-85, 5 percent for Xe-133 and Xe-131m, and 2 percent for the other noble gases and for the iodines.

Question 5

In section 7.8.1, “Radiation Source Terms” of WCAP-16736-P, you have generally described the basis for the re-calculation of your reactor coolant source term. Describe in detail the analysis methods and the specific assumptions including the change in your Iodine appearance rates. Also provide the regulatory basis for the changes that you cited in your application.

Response 5:

Part 1:

The primary coolant source term currently discussed in the UFSAR was developed in 1978 based on a core power of 3565 MWt, a 12 month fuel cycle, and operation with 1% fuel defects.

The primary coolant source term that is presented in WCAP-16376 is based on values that were calculated in 1990 for an 18 month fuel cycle and extended fuel burnup. The values obtained in the 1990 analysis were subjected to the same adjustments that were applied to the core source terms:

- The nuclide concentrations were increased by a factor of 1.02 to address the increase in licensed power from 3565 MWt to 3626 MWt (an increase of ~1.7%) plus the reduced calorimetric uncertainty of ~0.3%.
- The nuclide concentrations were also increased by a nominal amount to provide margin for ongoing fuel cycle design variations. The increases were 15 percent for Kr-85, 5 percent for Xe-133 and Xe-131m, and 2 percent for the other noble gases and for the iodines.

Note that, in performing the dose analyses in which primary coolant activity is released, the source term for iodines is based on a Tech Spec limit of 1.0 µCi/g of Dose Equivalent I-131 and reflects a fuel defect level of approximately 0.25% while the source term for the noble gases is based on 1.0% fuel defects.

Part 2:

The changes in iodine appearance rates from those currently reported in the VEGP UFSAR are the result of the changes in the equilibrium iodine concentrations that were determined and the parameter changes identified in Table 7.8-3 of WCAP-16736. These are:

Assumption	Current UFSAR Table 15A-7 Basis	Revised Analysis Basis
Letdown Flow Rate	75 gpm	140 gpm
Iodine Removal Provided in the Letdown Line	90%	100%
Primary Coolant Leakage Losses	0 gpm	12 gpm
Primary Coolant Water Mass	2.3E8 gm	2.53E8 gm

The cleanup rate for the current VEGP UFSAR values is only (0.9 * 75 gpm) = 67.5 gpm, while the revised cleanup rate is (140 gpm + 12 gpm) = 152 gpm. This is more than twice the iodine removal. With the increased cleanup, higher iodine appearance rates can be accommodated without exceeding the Tech Spec limit on iodine activity concentration. Thus, based on the assumption that the plant is operating at the Tech Spec limit of 1.0 µCi/g of Dose Equivalent I-131, it is expected that appearance rates for the longerlived iodines (I-131 and I-133) would increase by a factor of approximately two. The impact would be much less for the other isotopes which have short half-lives because their removal is dominated by radioactive decay.

The change in water mass has only a slight impact on the calculated iodine appearance rates.

<u>Question 6</u>

In table 7.8-3, “Assumptions Used in the Calculation of revised Iodine Appearance Rates,” you changed the percentage of Iodine removal by the Letdown Heat Exchanger from 90 percent to 100 percent removal. Please provide the regulatory basis or the justification for this non-conservative change in the iodine appearance rate assumption.

<u>Response 6:</u>

The iodine removal by the letdown line demineralizer is set at 100%, instead of 90%, in order to obtain a more conservative determination of iodine appearance rates. If a lower iodine removal efficiency is assumed, the iodine appearance rates will be reduced.

Question 7

What was the basis for the increased Control room unfiltered in-leakage to 835 cfm for unfiltered in-leakage and the 130 cfm for the pressurized Control room condition?

Response 7:

Unfiltered inleakage is assumed to be ½ the pressurization flow rate (1650/2) as suggested by Regulatory Guide 1.78 (June 1974) plus 10 cfm for ingress/egress. This value provides margin to the design requirement described in UFSAR 6.4.2.4 G. The current control room dose analysis for the limiting accident (LOCA) uses only 5 cfm for ingress/egress and has no margin for pressurized unfiltered inleakage. To bring the analysis into conformance with the more common industry practice, ingress/egress inleakage is increased to 10 cfm and the pressurized unfiltered inleakage is chosen so that the calculated doses meet GDC 19. The resulting value (130 cfm total) bounds the GL 2003-01 as-tested inleakage and provides margin for future design changes, or system or boundary leakage changes.

Question 8

For the accidents listed in RG 1.195 describe the re-analysis dose consequence calculation input assumptions and methods details. For any calculation assumptions or methods that are not in conformance with the guidance provide the safety justification for these differences. The applicable accidents include the following:

a) LOCA

b) Fuel Handling Accident

c) PWR Steam Generator Tube Rupture

d) Main Steam Line Break

e) Locked Rotor

f) Rod Ejection

Response 8:

The re-analysis dose consequences for MUR were not explicitly calculated using RG 1.195 assumptions. However a comparison between the assumptions used and RG 1.195 assumptions indicates the re-analysis dose consequences calculations conform to RG 1.195 guidance except as described below.

a) LOCA conforms. Input parameters are as described in enclosed excerpts of UFSAR Tables 15.6.5-9 and 15A-1.

b) Fuel Handling Accident conforms. Input parameters are described in enclosed excerpts of UFSAR Table 15.7.4-1.

c) Steam Generator Tube Rupture conforms, except position 1.4. Since all iodine removal (partitioning and filtration) is equal for all forms of iodine, all iodine is assumed to be elemental. Input parameters are described in enclosed excerpts of UFSAR Table 15.6.3-4.

d) Main Steam Line Break conforms, except position 1.4. Since all iodine removal (partitioning and filtration) is equal for all forms of iodine, all iodine is assumed to be elemental. Input parameters are described in enclosed excerpts of UFSAR Table 15.1.5-2.

e) RCP Locked Rotor conforms except positions 1, 1.3, and 2.6.
Position 1 - The locked rotor causes only clad failure, though the gap release fractions exceed those of RG 1.195, Table 2 as described in the enclosed excerpts of UFSAR Table 15.3.3-2.
Position 1.3 - Since all iodine removal (partitioning and filtration) is equal for all forms of iodine, all iodine is assumed to be elemental.
Position 2.6 - The transport model of Appendix E is used except scrubbing is notcredited.
Input parameters are described in enclosed excerpts of UFSAR Table 15.3.3-2.

f) Rod Ejection conforms with the following exceptions.

Position 1. Since the re-analysis was not specific to RG 1.195, the total activity released differs slightly. For containment airborne sources, the iodine release of 50% coupled with an airborne fraction of 45% yields 22.5% airborne fraction. However, the I-131 gap fraction dominates other iodines and is assumed to be 12% (vs. 10%), so the DEI release assumed bounds the RG 1.195 assumption of 25%. The steam generator leakage source is reduced by the RCS spill to the containment resulting in only 99.5% of the noble gas released to the RCS water available for leakage to the secondary system. Thus, while the iodine DEI source bounds the RG 1.195 assumption, the noble gas is slightly non-conservative. However, since WCAP Table 7.8-10 dose results indicate the whole body dose is about 3% of the limit, this difference is insignificant. Note that the dose results reported are for both pathways combined.

Positions 1.3 and 1.4.
Since all iodine removal (partitioning and filtration) is equal for all forms of iodine, all iodine is assumed to be elemental.

Position 3.4. The transport model of Appendix E is used except scrubbing is not credited.

Input parameters are described in enclosed excerpts of UFSAR Table 15.4.8-2.

<u>Question 9</u>

Table 7.8-3, “Summary of Revised MUR-PU control room Doses for the FHA with No Isolation of Containment,” provides a range of time to switch the CR Heating-Ventilation and Air Conditioning (HVAC) to emergency mode. Explain the mechanism for the CR HVAC switch to “emergency mode,” for the FHA and if this would be accomplished in time to meet regulatory dose limits to control room personnel or if the Operator(s) would need to take any actions to meet required CR personnel dose limits.

<u>Response 9:</u>

The range of dose vs. actuation time was included in Table 7.8-3 to provide the same level of detail as currently provided in the UFSAR. In the case of an FHA, the Control Room Emergency Filtration System (CREFS) will automatically initiate the emergency mode based on the CREFS intake radiation monitor (RE-12116 of 12117) reaching its trip setpoint as currently described in UFSAR 15.7.4.5.1.2 O. The design time to establish pressurization flow is ≤ 138 seconds; including radiation monitor response, signal processing, diesel generator and sequencer timing, and fan and damper actuation. No operator actions are required.

Calculations for control room doses using the fuel handling building X/Q, 138 second CREFS actuation time and input parameters in the enclosed UFSAR Table 15.7.4-1 excerpts meet GDC 19:

Thyroid dose	12.4 REM
Whole body dose	0.5 REM
Skin dose	5.5 REM.

TABLE 15.6.5-9 *EXCERPT* (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Source Data	
Core power level (MWt)	3636
Core activity released in the containment atmosphere after 20 s into the accident (%)	
Noble gas	100
Iodine	50
Core inventories	WCAP Table 7.8-1
Iodine distribution (%)	
Elemental	91
Organic	4
Particulate	5
Atmospheric Dispersion Factors	NL-07-1020, Encl. 5, Table III-2; and NL-07-1948
Control Room Parameters	Table 15A-1
Containment Leakage of Activity	
Containment leak rate (volume %/day)	
0 to 24 h	0.2
1 to 30 days	0.1
Unfiltered containment leakage (%)	100
Deposition iodine removal constants elemental iodine only (h^{-1})	4.8 (DF ≤ 200)

TABLE 15.6.5-9 *EXCERPT* (SHEET 2 OF 2)
Credit for containment sprays

Spray iodine removal constants (h^{-1})	
Elemental	10(1) (DF ≤ 21.4)
Organic	0.0
Particulate	4.2 (DF ≤ 50) 0.42 (DF > 50)
Duration of sprays (h)	2
Sprayed volume (%)	78
Unsprayed volume (%)	22
Number of fan coolers operating	2
Sprayed-unsprayed mixing rate (ft^3/min)	87,000
Containment volume (ft^3)	2.93×10^6
<u>Containment Purge of Activity</u>	
Purge flowrate (ft^3/min)	5000
Duration of purge, from accident initiation (s)	8.5
Reactor coolant iodine spike (µCi/g I-131 dose equivalent)	60
Reactor coolant activity airborne in the containment (%)	
Noble gas	100
Iodine	100
<u>Recirculation Leakage Outside Containment</u>	
Leak rate (gal/min, measured at 70 °F)	2
Temperature of recirculating fluid (°F)	
0 to 0.5 h	No recirculation
0.5 to 2.0 h	240
2.0 to 720 h	<212
Mass of water in the containment sump (lb)	6.77×10^6
Volume of building served by the auxiliary building emergency ventilation system (ft^3)	525,000
Auxiliary building emergency ventilation system parameters (for each of two trains)	
Recirculation flow (ft^3/min)	13,950
Discharge flow (ft^3/min)	2970
Elemental iodine filter efficiency (%)	90

(1) Calculated value is 22.5 h^{-1}.

TABLE 15A-1 *EXCERPT*

PARAMETERS USED IN ACCIDENT ANALYSIS

Control room

Free volume (ft^3)	1.72×10^5
Normal ventilation rate, unfiltered (ft^3/min)	3000
Time to isolate normal ventilation (s)	11.3
Time to establish emergency ventilation one unit operating (s)	99.3
Time to establish emergency ventilation, three units operating (s)	108
Emergency ventilation intake rate - one unit operating (ft^3/min)	1500
Emergency ventilation intake rate - three units operating (ft^3/min)	3870
Emergency ventilation rate, - one unit operating (ft^3/min)	17,100[a]
Emergency ventilation rate, - three units operating (ft^3/min)	47,500[a]
Unfiltered infiltration rate (ft^3/min) unpressurized control room	835
pressurized control room	130
Iodine removal efficiency for recirculation filters (all forms of iodine) (percent)	99
Iodine removal efficiency for intake filters (all forms of iodine) (percent)	99
High-efficiency particulate air filter efficiency (percent)	99

a. The value is for combined intake and recirculation air flow. The value also reflects the Technical Specification acceptance criterion of ± 10% of the nominal flow for a single train.

TABLE 15.7.4-1 *EXCERPT*

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

	Containment Open or In Fuel Building	Containment Closed
Source Data		
Core power level (MWt)	3636	3636
Radial peaking factor	1.70	1.70
Decay time (h)	100	100
Number of fuel assemblies affected	1.2	1.2
Fraction of fission product gases contained in the gap region of the fuel assembly	RG 1.195	RG 1.25 for all except I-131 (a fraction of 0.12)
Atmospheric Dispersion Factors	Table 15.6.5-9	Table 15A-2
Activity Release Data		
Percent of affected fuel assemblies gap activity released	100	100
Pool decontamination factors		
Elemental iodine	400	200
Organic iodine	1	1
Noble gas	1	1
Filter efficiency (%)	No credit	0
Building mixing volumes assumed (% total volume)	0	25
HVAC exhaust rate (ft^3/min)	N/A	15,000
Building isolation time (s)	No isolation	10+5
Activity release period (h)	2	Release terminated 10 s after containment isolation signal with 5 s allowed for signal generation
Control room (FHA only)		
Time to isolate normal ventilation (s)	48	
Time to establish emergency ventilation (s)	138	

TABLE 15.6.3-4 *EXCERPT* (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING RADIOLOGICAL CONSEQUENCES
OF A STEAM GENERATOR TUBE RUPTURE

I.	Source Data		
	A.	Core power level (MWt)	3636
	B.	Total steam generator tube leakage, prior to accident (gal/min)	1.0
	C.	Reactor coolant iodine activity:	
		1. Accident initiated spike	The initial RC iodine activities based on 1 µCi/gram of D.E. I-131 are presented in WCAP Table 7.8-2. The iodine appearance rates assumed for the accident initiated spike are 500 times those presented in WCAP Table 7.8-4.
		2. Preaccident spike	Primary coolant iodine activities based on 60 µCi/gram of D.E. I-131 are presented in WCAP Table 7.8-2.
		3. Noble gas activity	The initial RC noble gas activities based on 1-percent fuel defects are presented in WCAP Table 7.8-1.
	D.	Secondary system initial activity	Dose equivalent of 0.1 µCi/g of I-131 is 1/10 of the 1 µCi/gram of D.E. I-131 presented in WCAP Table 7.8-2
	E.	Reactor coolant mass, grams	2.53×10^8
	F.	Initial steam generator mass (each), grams	4.2×10^7
	G.	Offsite power	Lost at time of reactor trip
	H.	Primary-to-secondary leakage duration for intact SG, h	20
	I.	Species of iodine	100-percent elemental

TABLE 15.6.3-4 *EXCERPT* (SHEET 2 OF 2)

II.	Activity Release Data		
	A.	Ruptured steam generator	
		1. Rupture flow	See table 15.6.3-3
		2. Rupture flow flashing fraction	See figure 15.6.3-13
		3. Iodine scrubbing efficiency	See figure 15.6.3-15(1)
		4. Total steam release, lb	See table 15.6.3-3
		5. Iodine partition factor	100
	B.	Intact steam generators	
		1. Total primary-to-secondary leakage, gal/min	0.7
		2. Total steam release, lb	See table 15.6.3-3
		3. Iodine partition factor	100
	C.	Condenser	
		1. Iodine partition factor	100
	D.	Atmospheric Dispersion Factors	See table 15.6.5-9

(1) Although scrubbing is included in the UFSAR, no scrubbing credit has been included in the MUR dose analysis.

TABLE 15.1.5-2 *EXCERPT* (SHEET 1 OF 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A MAIN STEAM LINE BREAK

I.	Source Data		
	A.	Core power level (MWt)	3636
	B.	Total steam generator tube leakage (gal/min)	1
	C.	Reactor coolant iodine activity	
		1. Accident initiated spike	Initial activity equal to the DE 1.0 µCi/g of I-131 with an assumed iodine spike that increases the rate of iodine release into the reactor coolant by a factor of 500 times WCAP Table 7.8-4.
		2. Preaccident spike	An assumed preaccident iodine spike which has resulted in the DE of 60 µCi/g of I-131 in the reactor coolant. See WCAP Table 7.8-2.
	D.	Reactor coolant noble gas activity (both cases)	Based on 1-percent defective fuel. See WCAP Table 7.8-1 .
	E.	Secondary system initial activity	DE of 0.1 µCi/g of I-131.
	F.	Reactor coolant mass (g)	2.53×10^{8}
	G.	Secondary coolant mass, 4 generators (g)	1.9×10^{8}
	H.	Offsite power	Lost after trip
	I.	Primary-to-secondary leakage duration (h)	20
	J.	Species of iodine	100 percent elemental

Enclosure 2

TABLE 15.1.5-2 *EXCERPT* (SHEET 2 OF 3)

II.	Atmospheric Dispersion Factors	See table 15.6.5-9.
III.	Activity Release Data for the Steam Generator in the Faulted Loop	
	A. Primary-to-secondary leakrate (gal/min)[a]	0.35
	B. Steam released (lb)	
	0 to 0.5 h	167,000
	0.5 to 8.0 h	945
	C. Iodine Partition Factor	1
IV.	Activity Release Data for the Steam Generators in the Intact Loops	
	A. Primary-to-secondary leakrate (gal/min)[a]	0.65
	B. Steam released (lb)	
	0 to 2 h	424,000
	2 to 8 h	960,000
	8 to 20 h	1,920,000
	C. Iodine partition factor	0.01

a. Based on water at 590°F, 2250 psia.

TABLE 15.3.3-2 *EXCERPT*

PARAMETERS USED IN EVALUATING
THE RADIOLOGICAL CONSEQUENCES OF A
LOCKED ROTOR ACCIDENT

I.	Source Data	
	A. Core power level (MWt)	3636
	B. Total steam generator tube leakage (gal/min)	1
	C. Reactor coolant iodine activity prior to accident	An assumed preaccident iodine spike, which has resulted in the DE of 60 μCi/g of I-131 in the reactor coolant. See WCAP Table 7.8-2
	D. Gap activity released to reactor coolant from failed fuel	5 percent. (b).
	E. Reactor coolant noble gas activity	Based on 1-percent defective fuel. See WCAP Table 7.8-1.
	F. Secondary system initial activity	DE of 0.1 μCi/g of I-131.
	G. Reactor coolant mass (g)	2.3×10^8
	H. Secondary coolant mass, 4 generators (g)	1.9×10^8
	I. Offsite power	Lost after trip
	J. Primary-to-secondary leakage duration (h)	20
	K. Species of iodine	100-percent elemental
II.	Atmospheric Dispersion Factors	See table 15.6.5-9.
III.	Activity Release Data	
	A. Primary-to-secondary leak-rate (gal/min)[a] 1.0	
	B. Steam Released (lb)	
	0 to 2 h	555,000
	2 to 8 h	1,365,000
	8 to 20 h	2,730,000
	C. Iodine partition factor 100	

a. Based on water at 62.4 lb_m/ft^3.
b. Gap fractions are 10 percent of WCAP Table 7.8-1 core except Kr-85, I-127, I-129 are 30% and I-131 is 12%.

Enclosure 2

TABLE 15.4.8-2 *EXCERPT* (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CONTROL ROD EJECTION ACCIDENT

I.	Source Data		
	A.	Core power level (MWt)	3636
	B.	Total steam generator tube leakage (gal/min)	1
	C.	Reactor coolant iodine activity prior to accident	An assumed preaccident iodine spike, which has resulted in the DE of 60 μCi/g of I-131 in the reactor coolant. See WCAP Table 7.8-2.
	D.	Gap activity released to reactor coolant from failed fuel	10 percent.[(b)]
	E.	Melted fuel	0.25 percent of core (0.00125 of core iodines, 0.0025 of core noble gases, see WCAP Table 7.8-1)
	F.	Reactor coolant noble gas activity	Based on 1 percent defective fuel. See WCAP Table 7.8-1.
	G.	Secondary system initial activity	DE of 0.1 μCi/g of I-131.
	H.	Reactor coolant mass (g)	2.3×10^8
	I.	Secondary coolant mass, 4 generators (g)	1.9×10^8
	J.	Offsite power	Lost after trip
II.	Atmospheric Dispersion Factors		See table 15.6.5-9.

TABLE 15.4.8-2 *EXCERPT* (SHEET 2 OF 2)

III. Activity Release Data	
A. Containment	
1. Leak rate (percent/day)	0.2
2. Mass of primary coolant discharged to containment (lb)	
0 to 1600 s	9.3×10^4
1600 to 4700 s	3.4×10^5
4700 to 10000 s	6.9×10^5
3. Fraction of activity carried by reactor coolant spill that is assumed to be airborne	
Iodines	0.45
Noble gases	1.0
B. Steam generators	
1. Primary-to-secondary leak rate (gal/min)[a]	1.0
2. Mass of steam released (lb)	
0 - 214 s	4.9×10^4
3. Iodine partition factor	100

a. Based on water at 62.4 lb_m/ft^3.
b. Gap fractions are 10 percent of WCAP Table 7.8-1 core except Kr-85, I-127, I-129 are 30% and I-131 is 12%.

Enclosure 2

SG Tube Integrity and Chemical Engineering Branch

Question 1

The Case 3 analysis in Table 2-1 does not list the maximum value used for steam outlet moisture. Please confirm that the maximum value used was 0.25 percent. If 0.25 percent was not the maximum value used, state the maximum value used and discuss why a different value was used from the other cases.

Response 1:

Case 3 in Table 2-1 of WCAP-16736 is based on a moisture carryover of 0.25%.

Question 2

In Section 6.6.9, "Key Input Parameters and Assumptions" indicates that the reactor vessel outlet temperature for the MUR-PU is 618.2 °F, that minimum T_{hot} is 603.8 °F, that maximum T_{hot} is 620.0 °F, and that the maximum T_{hot} is a 1.8 °F increase from the current operating conditions. Please clarify whether the reactor vessel outlet temperature of 618.2 °F is the reactor vessel outlet temperature for the current operating conditions or for the MUR-PU conditions.

Response 2:

The T-hot assumed for current operating conditions is 618.2 degrees F. Therefore, the temperature increase in T-hot projected for the MUR-PU conditions is 1.8 degree based on the expected uprate temperature of 620 degrees F. (See Table 2-1, Note 2)

Question 3

In Section 6.6.9, "Description of Analyses and Evaluations and Results" for tube integrity uses temperatures (T_{hot} = 620 °F) and pressures (steam outlet pressure = 961 psia) from Case 3 in Table 2-1, which is the 0 percent plugging case. Discuss why temperature and pressure parameters from Case 4 in Table 2-1, which is the 10 percent plugging case, were not used, since Case 4 results in a lower steam outlet pressure of 941 psia.

Response 3:

Between Case 3 and Case 4 there is no difference in the anticipated vessel outlet temperatures. The Case 3 steam pressure is given as 961 psia, while the Case 4 value is 941 psia. The impact of choosing Case 3 (0% tube plugging) vs Case 4 (10% tube plugging) is that in the Case 3 conditions the structural limits are based on a normal operating differential pressure of 1289 psi while at Case 4 conditions the normal operating pressure differential is 1309 psi. The result of the difference in the two cases is a difference in the burst pressure limit. In accordance with VEGP Specification 5.5.9, "Vogtle Steam Generator (SG) Program," Section 5.5.9.b.1 structural integrity performance criterion, the burst pressure limit includes a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential. Based on this criterion, and the different normal operating differential pressures cited above, the burst pressure limit is 60 psi greater for Case 4 than for Case 3.

The requirement to meet the higher burst pressure capability results in a slight reduction in the limiting 100% throughwall depth crack, from 0.379" for $3\Delta P$ =3867 psi vs 0.372" for $3\Delta P$ = 3927 psi. The probability of detection for the shorter throughwall crack is not discernibly less than that for the slightly longer throughwall crack. Case 3 was chosen since the assumed tube plugging level (0%) more closely approximates the assumed plugging levels of the SGs during Cycle 13 for Unit 1 and during Cycle 12 for Unit 2: 0.33% for Unit #1 and 0.19% for Unit #2. Condition Monitoring and Operational Assessment calculations are based on the actual plant data for steam pressure. Thus the values current for the cycle preceding the outage are used for Condition Monitoring and the expected values for the ensuing cycle are used for Operational Assessment.

Question 4

In Section 6.6.9, "Effect of T_{hot} Temperature Increase on Steam Generator Tube Degradation," verify that the provided calculation for crack initiation and propagation of outside diameter stress corrosion cracking is correct. Using the supplied equation, energy of activation value, and temperatures resulted in an increase of 4.59 percent, as compared to the 4.88 percent value shown in the paper.

Response 4:

The correct increase in ODSCC is 4.59%.

Question 5

Confirm that the original coating qualification temperature and pressure profile, used by VEGP Units 1 and 2 to qualify Service Level I coatings, remains bounding in light of the power uprate pressures and temperatures. If the original coating qualification pressure and temperature profile is no longer bounding, discuss the conditions to be used and corrective actions that will be taken to assure that Service Level I containment coatings will be qualified.

Response 5:

There was no analysis performed for the LOCA and SLB inside containment M&E releases, therefore no new M&E releases were calculated for the MUR-PU. Therefore, the containment response associated with the LOCA and SLB inside containment is not changed by the MUR-PU. It has been confirmed that the original coating temperature and pressure qualification profile remain bounding for MURPU pressure and temperature conditions.

Vogtle Electric Generating Plant
Supplemental Information Supporting Acceptance Review,
Response to Request for Additional Information of November 20, 2007, and
Response to Request for Additional Information of November 29, 2007,
Regarding the Measurement Uncertainty Recapture Power Uprate
Amendment

Enclosure 3

SNC Response to the November 29, 2007, NRC RAI Questions

Enclosure 3

Reactor Systems Branch and Nuclear Performance and Code Review Branch

Question 1

Confirm that VIPRE-W (the version of VIPRE used for this MUR power uprate) is identical to the version of VIPRE approved in WCAP-14565 with no changes except those stated and approved in the WCAP.

Response 1:

The VIPRE-W code, which was used for the VEGP MUR-PU, is a configured QA version of the Westinghouse VIPRE-01 code that was approved in WCAP-14565-P-A (Reference 1). The Westinghouse QA program contains provisions for code change control and testing. Every code modification for QA configuration is evaluated in accordance with the Westinghouse procedure on compliance with NRC-approved codes and methods. The configured VIPRE-W version for VEGP MUR-PU application has been evaluated to be in full compliance with the methodology in WCAP-14565P-A, including the results and conclusions stated and approved in the WCAP.

Reference:

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

Question 2
Confirm that VIPRE is being used under an accepted quality assurance program with adequately trained users per Appendix B to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50.

Response 2:

VIPRE is used under the Westinghouse QA program that has been reviewed by the NRC to meet the requirements of 10CFR50, Appendix B, including proper user training and qualification procedures.

Question 3

Confirm that there is a 5-percent reduction factor to the flow entering the hot channel (per safety evaluation report for WCAP-14565).

Response 3:

Consistent with the VIPRE modeling for PWR safety analyses established in WCAP-14565-P-A, a 5% flow reduction to the hot assembly was assumed in all VIPRE DNBR calculations for the VEGP MUR-PU.

Question 4

Demonstrate that the plant parameters at the uprated conditions are still within the ranges of the correlations in VIPRE.

Response 4:

As discussed in Section 7.10.4 of WCAP-16736, DNBR calculations were performed at uprated conditions with the VIPRE code for all of the DNB-limited Chapter 15 events that were previously analyzed with the THINC subchannel analysis code at pre-MUR-PU conditions. The primary DNB correlation used in the VIPRE calculations for the VANTAGE+ fuel in VEGP is the WRB-2 DNB correlation. The W-3 DNB correlation is used where the primary DNB correlation is not applicable. The acceptance criteria for the DNBR calculations were that the results were within the parameter ranges of the appropriate DNB correlation and that the DNB design criterion was met.

Further discussion is provided in Section 7.10.5 of WCAP-16736 regarding compliance with the SER Conditions for the implementation of VIPRE, which demonstrates that the plant parameters associated with the VEGP MUR-PU are within the ranges of the correlations in VIPRE.

Question 5

In WCAP-16736-P, Section 7.3.1 (p. 7-5) states that the over-temperature-delta-T and over-power-delta-T setpoint evaluation are discussed in subsection 7.13. However, subsection 7.13 does not exist. Please provide or clarify where the evaluation is located.

Response 5:

The evaluation referred to in the RAI above is not applicable to VEGP MUR-PU. The sentence should not have been included in the referenced WCAP.

Question 6

The justification, that sufficient departure from nucleate boiling (DNB) and DNB ratio (DNBR) margin exists for the non-loss-of-coolant (non-LOCA)/transient analyses, was stated in many incidents in WCAP-16736-P. For example, page 7-7, states that DNB margin is allocated to specifically address the 1.7-percent power uprate. Page 7-4 states DNB margin in Updated Final Safety Analyses Report (UFSAR) 15.0.6 has been "allocated" such that the core thermal limits do not change. Page 7-6 states, "….34-percent margin to the DNBR limit. Based on the known DNB sensitivity to changes in power, the amount of margin is more than sufficient to offset the penalty associated with a 1.7 percent power uprate." However, insufficient detail was provided to make a determination on the adequacy of the statements. Provide a detailed evaluation of DNB/DNBR margin that demonstrates the allocation specifically addressing each non-LOCA event that utilizes the DNB or DNBR margin justification, given the uprated conditions.

Response 6:

A comparison of Table 7.10.4-1 and Table 7.10.4-2 for the events protected by the OTΔT reactor trip function shows that a maximum of 3.6% (thimble cell) of the available DNBR margin has been used for the 1.7% percent power uprate, while maintaining the same plant operating limits and trip setpoints. This is the amount of DNBR margin that was allocated to offset the impact of the 1.7% power increase. The available DNBR margin was obtained from the margin retained by the use of a higher DNBR limit for the safety analysis than is required to meet the 95/95 DNB design criterion.

Section 7.3 discusses the DNBR margins in the current licensing basis analyses. These margins are in excess of the 3.6% DNBR margin allocated for the 1.7% percent power uprate, as discussed in the preceding paragraph.

Question 7

In WCAP-16736-P, Section 7.3.1 states that for non-LOCA evaluations it is assumed that the reload-related inputs will not be impacted and will be verified as part of the standard reload process. Confirm the two parts of this statement are true or provide an explanation.

Response 7:

In Section 7.10.2, representative uprated reload VEGP cores were evaluated to determine the impact of the MUR-PU on the reload-related inputs for the safety analyses. It was concluded in Section 7.10.2 that adequate margins were available in the assumptions used in the safety analyses to accommodate the 1.7 percent uprated core power level. The assumption in Section 7.3.1 is consistent with this conclusion. As part of the standard Westinghouse reload methodology (WCAP-9272-P-A), all reload-related inputs are re-verified for each core reload.

Question 8

Further explanation is necessary for a comparison of the current licensing basis in UFSAR Table 15.0.3-2 and WCAP-16736-P Table 7.3-1. For approximately 10 events, the power level listed in parentheses in WCAP-16736 is the same as the UFSAR table. However, for approximately six events, the power level in parentheses is different than the UFSAR table.

Response 8:

Table 7.3-1 of WCAP-16736-P identifies the non-LOCA events that include a 2% power uncertainty and those that only consider a nominal 100% power level, as discussed on pages 7-4 and 7-5 of WCAP-16736-P, "Initial Power Conditions Assumed in the Safety Analyses (UFSAR Section 15.0.3)."

Table RAI-8 (below) provides a comparison of the initial Nuclear Steam Supply System (NSSS) power in the non-LOCA licensing analyses and the corresponding initial NSSS power for the 1.7% MUR-PU. The current licensing basis events analyzed with a 2% power uncertainty have a higher initial NSSS power than their corresponding 1.7% uprated initial power, except for the full power Steam System Piping Failure event (UFSAR Section 15.1.5) and the Turbine Trip event (UFSAR Section 15.2.3). The nominal pump heat, which is credited in these two events, has increased from 14 MWt (in the current analysis) to 17 MWt (in the MUR-PU). The increased pump heat of 3 MWt in the MUR-PU resulted in an initial NSSS power of 3654 MWt versus 3651 MWt in the current analyses.

For the full power steamline break event (UFSAR Section 15.1.5), the evaluation in Section 7.3 of WCAP-16736-P remains valid considering the increased initial NSSS power, since departure from nucleate boiling ratio (DNBR) margin was allocated to offset the MUR-PU impact.

For the Turbine Trip event (UFSAR Section 15.2.3), the evaluation in Section 7.3 of WCAP-16736-P remains valid (with respect to the effect on DNBR) considering the increased initial NSSS power, since DNBR margin was allocated to offset the MUR-PU impact. With respect to the effect on the peak reactor coolant system and steam generator pressure acceptance criteria, the current analysis has more than 50 psia and 90 psia of margin, respectively, to the peak pressure limits. These margins are judged to be more than sufficient to offset the penalty associated with the increased 3 MWt in the initial NSSS power. Therefore, the conclusion in WCAP-16736-P remains valid.

Table RAI-8: Vogtle Chapter 15 Non-LOCA Events – NSSS Power Comparison

Event Description	UFSAR Section	Current Licensing basis NSSS Power versus MUR-PU NSSS Power		
		Current Analysis Initial Power (% of NSSS, MWt)	MUR 1.7% Power Uprate Initial NSSS (MWt)	Limiting Initial NSSS (MWt) for UFSAR Table 15.0.3-2 (for MUR-PU)
Feedwater System Malfunctions (decreased FW temp)	15.1.1(1)			
Feedwater System Malfunctions (increased FW flow)	15.1.2	100% of 3579 = 3579	**3643**	3643
Excessive Increase in Secondary Steam Flow	15.1.3	100% of 3579 = 3579	**3643**	3643
Inadvertent Opening of SG relief or safety valve	15.1.4(1)			
Steam System Piping Failure	15.1.5	102% of 3579 = 3651	100.3% of 3643 = **3654**	3654
Steam Pressure Regulator Failure (decreased steam flow)	15.2.1(2)			
Loss of External Electrical Load	15.2.2(1)			
Turbine Trip	15.2.3	102% of 3579 = 3651	100.3% of 3643 = **3654**	3654
Inadvertent Closure of MSIVs	15.2.4(1)			
Loss of Condenser Vacuum	15.2.5(1)			
Loss of Non-Emergency ac Power	15.2.6	102% of 3585 = **3657**	100.3% of 3646 = 3657	3657
Loss of Normal Feedwater	15.2.7	102% of 3585 = **3657**	100.3% of 3646 = 3657	3657
Feedwater System Pipe Break	15.2.8	102% of 3585 = **3657**	100.3% of 3646 = 3657	3657
Partial Loss of Forced Reactor Coolant Flow	15.3.1	100% of 3585 = 3585	**3646**	3646
Complete Loss of Forced Reactor Coolant Flow	15.3.2	100% of 3585 = 3585	**3646**	3646
Reactor Coolant Pump Shaft Seizure (Peak Pressure)	15.3.3	102% of 3585 **= 3657**	100.3% of 3646 = 3657	3657
Reactor Coolant Pump Shaft Seizure (Rods in DNB)	15.3.3	100% of 3585 = 3585	**3646**	3646
Reactor Coolant Pump Shaft Break	15.3.4(1)			
Uncontrolled RCCA Bank Withdrawal from subcritical	15.4.1	0%	n/a	
Uncontrolled RCCA Bank Withdrawal at power	15.4.2	100% of 3585 = 3585	**3646**	3646
RCCA Misalignment (Dropped Rod)	15.4.3	100% of 3565 = 3565	**3626**	3626
Startup of an Inactive RCP at incorrect temperature	15.4.4	72% of 3579 = **2577**	70.3% of 3643 = 2561	2577
Failure of Flow Controller in BWR loop	15.4.5(2)			
Uncontrolled Boron Dilution	15.4.6	100% of 3565 = 3565	**3626**	3626
Spectrum of RCCA Ejection	15.4.8	102% of 3564.7 = **3636**	100.3% of 3626 = 3636	3636
Steamline Break with coincident RWAP	15.4.9(2)			
Inadvertent Operation of the ECCS	15.5.1	102% of 3585 = **3657**	100.3% of 3646 = 3657	3657
CVCS Malfunction (increased RCS inventory)	15.5.2(1)			
BWR Loop transients	15.5.3(2)			
Inadvertent Opening of PZR Safety or Relief Valve	15.6.1	100% of 3579 = 3579	**3643**	3643

(1) Bounded by another event
(2) Not applicable to VEGP

Current Core Power = 3564.7 MWt (rounded to 3565 MWt); NSSS Power = (Core Power + pump heat) MWt; where, nominal pump heat = 14 MWt and maximum pump heat = 20 MWt.

MUR Core Power = **3626** MWt; NSSS Power = (Core Power + pump heat) MWt; where, nominal pump heat = **17** MWt and maximum pump heat = 20 MWt.

Table 7.3-1 of WCAP-16736-P identifies the non-LOCA events that include a 2% power uncertainty and those that only consider a nominal 100% power level, as discussed on pages 7-4 and 7-5 of WCAP-16736-P, "Initial Power Conditions Assumed in the Safety Analyses (UFSAR Section 15.0.3)."

Table RAI-8 (below) provides a comparison of the initial Nuclear Steam Supply System (NSSS) power in the non-LOCA licensing analyses and the corresponding initial NSSS power for the 1.7% MUR-PU. The current licensing basis events analyzed with a 2% power uncertainty have a higher initial NSSS power than their corresponding 1.7% uprated initial power, except for the full power Steam System Piping Failure event (UFSAR Section 15.1.5) and the Turbine Trip event (UFSAR Section 15.2.3). The nominal pump heat, which is credited in these two events, has increased from 14 MWt (in the current analysis) to 17 MWt (in the MUR-PU). The increased pump heat of 3 MWt in the MUR-PU resulted in an initial NSSS power of 3654 MWt versus 3651 MWt in the current analyses.

For the full power steamline break event (UFSAR Section 15.1.5), the evaluation in Section 7.3 of WCAP-16736-P remains valid considering the increased initial NSSS power, since departure from nucleate boiling ratio (DNBR) margin was allocated to offset the MUR-PU impact.

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Table RAI-8: Vogtle Chapter 15 Non-LOCA Events – NSSS Power Comparison

Event Description	UFSAR Section	Current Licensing basis NSSS Power versus MUR-PU NSSS Power		
		Current Analysis Initial Power (% of NSSS, MWt)	MUR 1.7% Power Uprate Initial NSSS (MWt)	Limiting Initial NSSS (MWt) for UFSAR Table 15.0.3-2 (for MUR-PU)
Feedwater System Malfunctions (decreased FW temp)	15.1.1(1)			
Feedwater System Malfunctions (increased FW flow)	15.1.2	100% of 3579 = 3579	**3643**	3643
Excessive Increase in Secondary Steam Flow	15.1.3	100% of 3579 = 3579	**3643**	3643
Inadvertent Opening of SG relief or safety valve	15.1.4(1)			
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Steamline Break with coincident RWAP	15.4.9(2)			
Inadvertent Operation of the ECCS	15.5.1	102% of 3585 = **3657**	100.3% of 3646 = 3657	3657
CVCS Malfunction (increased RCS inventory)	15.5.2(1)			
BWR Loop transients	15.5.3(2)			
Inadvertent Opening of PZR Safety or Relief Valve	15.6.1	100% of 3579 = 3579	**3643**	3643

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