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RECIP.NAME RECIPIENT AFFILIATION
Records Management Branch (Document Control Desk)

See Reports

SUBJECT: Forwards proprietary response to NRC request for addl info on Topical Rept DPC-NE-3005-P, "UFSAR Chapter 15 Transient Analysis Methodology." TR previously submitted for NRC review by util ltr dtd 970730.Encl withheld,per 10CFR2.790.

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July 23, 1998

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

Subject: Duke Energy Corporation

Oconee Nuclear Station, Units 1, 2 and 3
Docket Numbers 50-269, 50-270, and 50-287

Response to NRC Request for Additional Information on Topical Report DPC-NE-3005-P, "UFSAR Chapter 15 Transient Analysis Methodology."

This submittal contains information that Duke Energy Corporation considers PROPRIETARY and is being made pursuant to 10CFR 2.790.

By letter dated April 13, 1998 the NRC requested additional information on Topical Report DPC-NE-3005P, "UFSAR Chapter 15 Transient Analysis Methodology." This topical report had been previously submitted for NRC review by Duke letter dated July 30, 1997.

The questions contained in the April 13 NRC letter, and the corresponding Duke answers, are provided in Attachment 1 to this letter.

Additionally, Attachment 2 provides editorial corrections and minor revisions to Topical Report DPC-NE-3005-P. These changes to this topical report have been identified since the July 30, 1997 submittal of this document. Attachment 3 provides the non-proprietary version of these changes.

Some of the information contained in Attachment 2 is considered proprietary. In accordance with 10CFR 2.790, Duke requests that this information be withheld from public disclosure. An affidavit which attests to the proprietary nature of the affected information is included with this letter.

APOI

Change PDR Ltr Enc 1 1 w/o prop.

In the response to Question 9 (see Attachment 1), Duke provides the schedule for implementing station modifications to correct slow response time associated with the turbine trip circuitry channels. Oconee has preliminarily scheduled the turbine stop valve closure circuitry modification beginning with the Unit 3 End-of-cycle 18 outage, currently scheduled for March 2000. Implementation for Unit 1 would be in September 2000, and Unit 2 would be in April 2001. If the modification process alters the preliminary schedule, Duke will notify the NRC of this change by the end of 1997.

Please address any comments or questions regarding this matter to J. S. Warren at (704) 382-4986.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachments

xc:

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AFFIDAVIT

1. I am Executive Vice President of Duke Energy Corporation; and as such have the responsibility for reviewing information sought to be withheld from public disclosure in connection with nuclear power plant licensing; and am authorized on the part of said Corporation (Duke) to apply for this withholding.

2. I am making this affidavit in conformance with the provisions of 10CFR 2.790 of the regulations of the Nuclear Regulatory Commission (NRC) and in conjunction with Duke's application for withholding, which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke in designating information as proprietary or confidential.

4. Pursuant to the provisions of paragraph (b)(4) of 10CFR 2.790, the following is furnished for consideration by the NRC in determining whether the information sought to be withheld from public disclosure should be withheld.

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

    (ii) The information is of a type that would customarily be held in confidence by Duke. The information consists of analysis methodology details, analysis results, supporting data, and aspects of development programs relative to a method of analysis that provides a competitive advantage to Duke.

M. S. Tuck

M. S. Tuckman

(Continued)

(iii) The information was transmitted to the NRC in confidence and under the provisions of 10CFR 2.790, it is to be received in confidence by the NRC.

(iv) The information sought to be protected is not available in public to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is marked in Attachment 2 to Duke Energy Corporation letter dated July 23, 1998; SUBJECT: Response to NRC Request for Additional Information on Topical Report DPC-NE-3005P, "UFSAR Chapter 15 Transient Analysis Methodology." This information enables Duke to:

(a) Respond to NRC requests for information regarding transient response of Babcock & Wilcox PWRs.

(b) Simulate UFSAR Chapter 15 transients and accidents for Oconee Nuclear Station.

(c) Perform safety evaluations per 10CFR50.59.

(d) Support Facility Operating Licenses/Technical Specifications amendments for Oconee Nuclear Station.

M. S. Tuck

M. S. Tuckman

(Continued)

(vi) The proprietary information sought to be withheld from public disclosure has substantial commercial value to Duke.

(a) It allows Duke to reduce vendor and consultant expenses associated with supporting the operation and licensing of nuclear power plants.

(b) Duke intends to sell the information to nuclear utilities, vendors, and consultants for the purpose of supporting the operation and licensing of nuclear power plants.

(c) The subject information could only be duplicated by competitors at similar expense to that incurred by Duke.

5. Public disclosure of this information is likely to cause harm to Duke because it would allow competitors in the nuclear industry to benefit from the results of a significant development program without requiring commensurate expense or allowing Duke to recoup a portion of its expenditures or benefit from the sale of the information.

M. S. Tuckman

M. S. Tuckman

(Continued)

M. S. Tuckman, being duly sworn, states that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth within are true and correct to the best of his knowledge.

M.S. Tuckman

M. S. Tuckman, Executive Vice President

Subscribed and sworn to before me this 23RD day of July, 1998

Mary P. Nelms

Notary Public

My Commission Expires:

JAN 22, 2001

SEAL

bxc:

L. A. Keller
J. E. Burchfield
G. B. Swindlehurst
J. E. Smith (Commitment Included in Response to Question 9)
ELL

Attachment 1

Question 1

Please explain why there are two options available for input of the nodal axial power profile to the computer code VIPRE-01.

a) What differences result between the use of a linear interpolation compared to a spline fit?
b) How does the user determine which option to use?

Response to Question 1

Originally, the spline fit was developed to replace the linear interpolation routine because it was recognized that linear interpolation did not conserve area under the curve (straight line from point to point), and would therefore under-predict the axial shape uniformly (non-conservative for DNB predictions). Furthermore, the linear interpolation routine would grossly under-normalize unless the user specifically input data at the endpoints (if not, linear interpolation would default to zero values at the endpoints). After developing the spline fit, Duke recognized the need to be able to duplicate previous analyses that used linear interpolation; so, instead of replacing linear interpolation with the spline fit, an additional option was added.

Like linear interpolation, the spline fit also has limitations at the endpoints. The spline fit conserves area under the curve at all locations except the endpoints, for which it makes an estimate. For this reason, the spline fit also does not normalize to 1.0 unless the user specifies endpoints. Sensitivity studies have shown that, unlike linear interpolation, specifying endpoints to force the spline fit to normalize to 1.0 has negligible effect on DNBR predictions, since the spline fit makes an estimate at the endpoints (as opposed to defaulting to a zero value as with the linear interpolation routine). Generally, bottom peaked spline fit shapes slightly under-normalize, and top peaked spline fit shapes slightly over-normalize. When comparing the two options directly, the spline fit (without specifying endpoints that force normalization to 1.0) will usually give an equal or slightly more conservative DNBR prediction than the linear interpolation routine (with or without specifying endpoints that force it to normalize to 1.0).

If the user is duplicating analyses that have previously been performed with linear interpolation, then the linear interpolation option should be selected for consistency. If the user is performing an analysis for which axial shape input must be generated for a large number of axial levels, the spline fit should be selected for the reasons stated above.

Question 2

When will the power hot channel factor and the local heat flux hot channel factor be input to VIPRE-01 to calculate the departure from nucleate boiling ratio (DNBR) in a subchannel? How will this cause the results of a DNBR calculation to differ from what is currently obtained?

Response to Question 2

The local heat flux hot channel factor has not been applied in Oconee DNBR analyses beginning with the Oconee Unit 1 Cycle 14 reload (Reference the Oconee 1 Cycle 14 Reload Report, Letter, M. S. Tuckman (Duke) to NRC Document Control Desk, May 7, 1991)

The power hot channel factor is input to VIPRE-01 to calculate the DNBR when the DNBR analysis accounts for uncertainties directly, i.e. when the Statistical Core Design (SCD) methodology is not used. The rod ejection DNB analysis is the only transient DNB analysis in DPC-NE-3005-P not employing the SCD methodology. This is due to the core power level exceeding the range of the SCD methodology during the rod ejection analysis.

The power hot channel factor has been applied during the entire operating history of Oconee. The application of the power hot channel factor is not new to the Oconee licensing basis, therefore there is no difference being introduced in the proposed methodology.

Question 3

The Babcock and Wilcox (B&W) Correlation (BWC) and the BWC mixing vane critical heat flux correlations have been previously approved for use in VIPRE-01. Why are these considered additional features to be added to VIPRE-01/MOD2F?

Response to Question 3

Section 2.3.1 of DPC-NE-3005-P shows a summary of additional features and editorial changes existing in the Duke VIPRE-01/MOD2F code version relative to the standard EPRI VIPRE-01/MOD2 version. With the exception of adding the BWU-Z CHF correlation, all other features and changes listed in Section 2.3.1 were added and made in the previous Duke versions (MOD2A to MOD2E). Therefore, the BWC and BWC mixing vane critical heat flux correlations are not considered as additional features to be added to VIPRE-01/MOD2F. They are listed only to distinguish from the standard EPRI code version.

Question 4

Briefly describe the enhanced iteration logic used by VIPRE-01 to converge to a minimum DNBR (MDNBR) limit.

Response to Question 4

The VIPRE-01 code uses the secant method to perform the option to iterate on a specified parameter to an MDNBR limit. The logic in the original VIPRE-01/MOD2 code did not always cause the iteration to converge when the input parameter yielded a MDNBR value significantly different from the target MDNBR limit. Logic was therefore added such that if the MDNBR resulting from the parameter input value is different from the target MDNBR limit by a value of 0.75, the first guess at the iterated parameter would increase the input value by 10% instead of the 1% as in the original code version.

Additionally, each iteration of the specified parameter is used to calculate a MDNBR in the secant method. The calculated MDNBR is then compared to the target MDNBR limit to generate a delta-difference MDNBR value. The next guess of the parameter value is based on this delta-difference MDNBR value. In the original code version, if the next iteration yielded the same delta-difference MDNBR value, the logic would not increase the parameter value and the iteration process would stall. This problem is circumvented by increasing the specified parameter value by an amount of 0.01 when the delta-difference MDNBR does not change between iterations.

Question 5

The moderator (boron) dilution accident for Oconee is analyzed only from conditions of power operation (Mode 1) and refueling (Mode 6). Provide analyses for Modes 2 through 5 and demonstrate that the results conform to those specified in SRP 15.4.6.

Response to Question 5

The analysis methodology and acceptance criteria that were utilized in the original UFSAR Chapter 15 analyses constitute, in part, the design basis of the plant on which the issuance of the operating license was based. Oconee's operating license was issued prior to the Standard Review Plan. Therefore, the Standard Review Plan is not applicable to Oconee. Duke is not proposing to adopt the Standard Review Plan guidelines for including moderator dilution accident analyses for Modes 2 through 5. Duke is upgrading the Modes 1 and 6 analyses to be more representative of modern analyses.

Question 6

The acceptance criterion for the Oconee analysis of the rod ejection accident is that the offsite dose will be less than 100 percent of the 10 CFR Part 100 limits. However, NRC Regulatory Guide 1.77 and Standard Review Plan 15.4.8 specify that calculated doses should be well within 10 CFR Part 100 limits, where "well within" is defined as 25 percent of the 10 CFR Part 100 exposure guidelines values. Please modify the Oconee dose acceptance criterion accordingly.

Response to Question 6

The analysis methodology and acceptance criteria that were utilized in the original UFSAR Chapter 15 analyses constitute, in part, the design basis of the plant on which the issuance of the operating license was based. Oconee's operating license was issued prior to the Standard Review Plan. Therefore, the Standard Review Plan is not applicable to Oconee. Duke is not proposing to adopt the Regulatory Guide 1.77 or the Standard Review Plan guidelines for offsite dose acceptance criteria being limited to a fraction of the 10 CFR Part 100 limits. The Part 100 dose acceptance criteria were the basis for the issuance of the Oconee operating license, and were accepted by the staff at that time. Duke's methodology will continue to comply with the original licensing basis.

Question 7

Section 1.3 - Describe the Emergency Operating Procedures (EOPs) available at Oconee that will manually start the Emergency Feedwater (EFW) System to back up the non-safety grade equipment in mitigating the loss of reactor coolant flow transient. Confirm that the operator actions could be taken in time to bound the results of the analysis.

Response to Question 7

The EFW System is a three pump/two train safety-grade system designed to automatically start and feed both steam generators on low main feedwater pump turbine hydraulic oil pressure or low steam generator level. Either of these start signals infers that a loss of the non-safety grade main feedwater system has occurred. The multiple pump and redundant train design of the EFW System ensures that at least one steam generator will automatically be fed following this event. EFW flow will be automatically controlled to the appropriate minimum level (any RCPs on) or the natural circulation level (all RCPs off).

The discussion in Section 1.3 (Credit for Control Systems and Non-Safety Components and Systems) describes a scenario where 1) a loss of all RCPs occurs, which requires that the SG level be raised to the natural circulation setpoint, 2) the MFW System continues to operate, 3) the non-safety Integrated Control System (ICS) fails to raise the SG level from the post-trip minimum level to the natural circulation level setpoint, and 4) the EFW autostart setpoints are not reached and EFW does not actuate. For this scenario operator action is required to identify the ICS failure and to respond by increasing SG levels to the natural circulation setpoint with either MFW or EFW. In the Oconee EOP, Step 5.3 (the third step) in the Subsequent Actions section directs the operator to "Throttle Main or Emergency FDW as required to control SG level(s) and RCS temperature". Based on simulator experience, this step will be reached in less than 5 minutes for this scenario. EOP Step 15.12 specifies "IF no RCPs are operating . . . Verify SG levels approaching 50% OR" (50% OR is the natural circulation setpoint). It is expected that this step will be reached in 10 minutes for this scenario. These steps clearly guide the operator to address the ICS failure of concern. Increasing SG levels beginning at this time is very sufficient for establishing conditions for natural circulation and long-term decay heat removal.

The duration of the loss of flow analysis is very short and focuses on the approach to the DNBR limit as a result of the loss of some or all RCPs. MFW and EFW are not relied on to demonstrate that the DNBR acceptance criterion is met. Therefore, there is no explicit modeling of the MFW or EFW Systems in the analysis other than the use of MFW to establish the secondary heat sink at the initial conditions.

Question 8

Section 1.3 - It is stated that for certain failures in the safety grade EFW System, credit is taken for realigning EFW flow through the non-safety Main Feedwater System and this design aspect has been reviewed and approved by the NRC. Provide the documentation for this issue.

Response to Question 8

The documentation for this issue is the following references:

1. Letter, William O. Parker (Duke), to Harold R. Denton (NRC), December 21, 1979, Attachment 2 - Emergency Feedwater System Reliability Analysis for the Oconee Nuclear Generating Station. Refer to Section 2.1.3 on p. 6 for a docketed description of the EFW realignment.

2. Letter, William O. Parker (Duke), to Harold R. Denton (NRC), July 23, 1980, Attachment 2 - Emergency Feedwater System. Refer to Section 2.1.3 on p. 2-2 for a docketed description of the EFW realignment.

3. Letter, William O. Parker (Duke), to Harold R. Denton (NRC), April 3, 1981, Response to NRC RAI Dated 11/14/80 - Auxiliary Feedwater System Reliability Evaluation. Refer to the response to Question 14.

4. Letter, John F. Stolz (NRC) , to William O. Parker (Duke), August 25, 1981, SER for NUREG-0737 Item II.E.1.1, "Auxiliary Feedwater System Evaluation" (Refer to Item 6 on p. 18).

Question 9

Section 1.3 - One of the turbine trip circuitry channels has a slower response time than the value assumed in the analysis methodology. Confirm that the required modification will be completed prior to the approval of the proposed methodology.

Response to Question 9

Oconee has preliminarily scheduled the turbine stop valve closure circuitry modification for implementation beginning with the Oconee Unit 3 end-of-cycle 18 outage, currently scheduled for March 2000. Implementation for Unit 1 would be in September 2000, and Unit 2 would be in April 2001 based on their respective refueling outages. The modification process will finalize the scope and schedule for this modification by the end of 1998. If the modification process alters the preliminary schedule, Duke will notify the staff of this change by the end of the year.

Considering that the current design has been the licensing basis since 1973, the above implementation plan, which is an enhancement to the redundancy of the turbine stop valve actuation circuitry, is considered sufficient. This is supported by the excellent reliability data for the first actuation channel, which has been credited in the current UFSAR licensing basis analyses.

Implementation of the proposed methodology is planned beginning with the startup of Oconee Unit 1 Cycle 18 in June 1999. This is desired in order to enable upgrading the UFSAR Chapter 15 analyses to establish a new baseline for safety reviews and UFSAR verification activities in progress. With the proposed implementation plan, this represents essentially one year of operation with the proposed analysis methodology in place prior to the upgrade of the turbine stop valve circuitry. NRC approval of this implementation plan is requested.

Question 10

Section 1.3 - Confirm that the use of the non-safety grade turbine trip circuitry in the transient analysis is consistent with the Oconee licensing basis.

Response to Question 10

The UFSAR Chapter 15 analyses include an immediate turbine trip following all reactor trip. This assumption is typical of UFSAR Chapter 15 analyses, including other PWRs such as Westinghouse plants. A failure of the turbine to trip is considered as an initiating event that causes an overcooling event that is bounded by the steam line break analysis. Since this assumption has been in the Oconee UFSAR since the operating license was issued, it is the licensing basis assumption.

Question 11

Section 1-3 - It is stated that the capability to remotely throttle certain non-safety grade valves (including the steam generator drain lines) is credited in the analysis methodology. Identify the areas that are affected by this assumption and confirm that they are within the Oconee current licensing basis.

Response to Question 11

The non-safety grade valves credited in the analysis methodology are the atmospheric dump valves (ADVs), the turbine bypass valves (TBVs), valves in the startup feedwater flow path, the pressurizer spray valve, and valves in the steam generator drain lines. The TBVs are remotely controlled, while the remainder of these valves are manual-local controlled valves.

The ADVs and TBVs are credited in the proposed SGTR analysis to both cool the unit down to DHR system conditions and to control level in the ruptured SG. The TBVs are considered part of the current Oconee licensing basis since they are credited in the current Ch. 15 SGTR analysis for cooling the plant down to DHR System conditions. The ADVs are not considered part of the current licensing basis with regard to UFSAR Ch. 15.

The proposed SGTR analysis methodology credits bypassing a stuck-closed EFW control valve via the alternate Main Feedwater System flowpath. The use of this alternate flowpath is part of the current licensing basis (References: 1) Letter, William O. Parker (Duke), to Harold R. Denton (NRC), December 21, 1979, Attachment 2 - Emergency Feedwater System Reliability Analysis for the Oconee Nuclear Generating Station. Refer to Section 2.1.3 on p. 6 for a docketed description of the EFW realignment; 2) Letter, John F. Stolz (NRC) , to William O. Parker (Duke), August 25, 1981, SER for NUREG-0737 Item II.E.1.1, "Auxiliary Feedwater System Evaluation" (Refer to Item 6 on p. 18)).

The pressurizer spray valve is assumed to be operable in the proposed SGTR analysis methodology. The use of the spray valve during a SGTR event is part of the current licensing basis (References: 1) Letter, M. S. Tuckman (Duke), to NRC Document Control Desk, March 27, 1991, G. L. 90-06; 2) Letter, L. A. Wiens (NRC), to J. W. Hampton (Duke), June 9, 1994, SER regarding G. L. 90-06)

The SG drain lines are credited in the proposed SGTR analysis methodology to control level in the ruptured SG when steaming of this SG is no longer effective in accomplishing this action (i.e., when SG pressure is very low). The use of these drain lines is not currently within the licensing basis for ONS.

Question 12

Section 2.2 - It is indicated that the advanced solution scheme and correlations of the RETRAN-3D computer code are used in the proposed analysis methodology. Provide further discussions on how the proposed methodology could be approved without a detailed review of the RETRAN-3D code.

Response to Question 12

DPC-NE-3005-P includes several comparison analyses which demonstrate similar transient results for RETRAN-02 and RETRAN-3D. In these analyses RETRAN-3D is used in the "RETRAN-02 mode", which refers to applying the code without any of the significant new RETRAN-3D models (three-dimensional core kinetics, non-equilibrium field equations, non-condensible gas flow). The new solution method (faster execution time) and some improved correlations in RETRAN-3D are the scope of the application of RETRAN-3D that is proposed in the topical report. The intent of the submittal is to demonstrate by direct comparison of analysis results that the improved RETRAN-3D code gives essentially identical results as RETRAN-02. Comparing a new code version (RETRAN-3D) to an approved code version (RETRAN-02) is a logical process for validating the new code, and has precedent in the industry.

RETRAN-3D is maintained by EPRI as a quality-assured code under EPRI's Appendix B program. RETRAN-3D has been submitted for NRC review and approval (Letter, G. B.

Swindlehurst (Duke Power on behalf of RETRAN Maintenance Group), to T. E. Collins (NRC), July 8, 1998). The details of RETRAN-3D, including the new solution method and upgraded correlations are in this reference. The proposed approach was intended as a first step in the NRC approval process for RETRAN-3D.

Implementation of the DPC-NE-3005-P methodology does not require NRC-approval of the RETRAN-3D scope of the submittal.

Question 13

Section 9.3 - Assuming a single failure of the pump monitor trip, will Cases 3 and 5 become more limiting than Cases 2 and 4 due to a reactor trip from flux/flow?

Response to Question 13

Case 3 is a loss of four RCPs from an initial condition that assumes four RCPs are operating. Case 5 is a loss of three RCPs from an initial condition that assumes three RCPs are operating. The pump monitor trip is designed to trip the reactor when two or more RCPs trip at power levels greater than 2% rated thermal power. Assuming a single failure in the pump monitor trip function results in a reactor trip when three or more RCPs trip. For both Cases 3 and 5, a single failure in the pump monitor trip will not prevent a pump monitor trip since the combination of the number of pumps tripped and/or not operating is greater than or equal to three. Therefore, the single failure of concern has no effect on Cases 3 and 5. Analyses have shown that Cases 2 and 4 result in more severe transient results than Cases 3 and 5.

Question 14

Section 9.3.1.4 - Discuss the assumed delay time of the reactor trip.

Response to Question 14

The conservative trip delay time referred to in Section 9.3.1.4 actually refers to a conservative trip delay time for each trip. Thus, the trip delay time assumed for the pump monitor trip function conservatively bounds the calculated pump monitor trip time delay, while the trip delay time assumed for the flux/flow/imbalance trip function conservatively bounds the calculated flux/flow/imbalance trip time delay. The delay times are given in Table 4-2.

Question 15

Section 10 (Locked Rotor) - Provide a revised analysis methodology to incorporate the following:

a) Assume a loss of offsite power with this event

b) Include peak system pressure as a part of the acceptance criteria for this event

c) Since a flux/flow is the trip function for this event, a single failure of the pump monitor trip becomes a non-limiting failure. Identify the most limiting single failure for this event.

Response to Question 15

a) The assumption of a loss of offsite power concurrent with the locked rotor event is not part of Oconee's current licensing basis. The operating license was issued based on the current assumption. Duke is not proposing to change this assumption.

b) Duke will include a peak Reactor Coolant System pressure acceptance criterion of 110% of design pressure for the locked rotor accident. The results will be included in the UFSAR.

c) For locked rotor, the case initiated from three RCPs in operation is the limiting case in terms of approach to DNB. Since the pump monitor trip normally actuates when two or more pumps are in a tripped condition, it is normally expected that a pump monitor trip would be actuated for this case. By assuming a single failure in the pump monitor trip function, the three RCP case becomes limiting due to the longer trip time delay associated with the flux/flow/imbalance trip. For the four RCPs in operation initial condition, no single failure could be identified which would affect the analysis results due to the short duration of the event.

Question 16

Section 12.0 (Turbine Trip) - It is indicated that no credit is taken for EFW flow in this event since the peak reactor coolant system (RCS) pressure will occur prior to the EFW actuation. The staff does not agree with this approach. We will require an analysis that shows there will not be a second peak pressure higher than the first peak during this transient. With an insufficient EFW flow rate, the RCS pressure could become the problem later in the transient. Also, the concern of the solid pressurizer should be addressed during the longer-term with respect to EFW flow.

Response to Question 16

The analysis methodology for the turbine trip event was intended to quantify the short-term Reactor Coolant System peak pressure, which occurs at 7.5 seconds, shortly after the reactor trips. The results show that the pressurizer code safety valves are not challenged during this short-term pressure peak following a turbine trip event, and therefore the turbine trip is non-limiting relative to other events that do challenge the code safety valves. The turbine trip event does not require an assumption of a loss of the Main Feedwater System. That would constitute two initiating events. On p. 12-5 of the topical report, it states, "Therefore, main feedwater is isolated on turbine trip to maximize the primary system pressure ." This statement refers to the post-trip runback of Main Feedwater to control to the minimum steam generator level setpoint. To reach this setpoint, main feedwater flow is "isolated" until the level setpoint is reached, and then flow is restored to the steam generator. Since the analysis is of short duration and the low level setpoint is not reached, the main feedwater flow remains isolated, With continued availability of the Main Feedwater System, the high flow capacity ensures that the long-term peak pressure will be bounded by those events for which the MFW System is not available. The focus of the analysis was on the short-term pressure peak, with the result being that this event did not even lift the pressurizer code safety relief valves. With the Main Feedwater System still available to provide an abundant heat sink, the turbine trip event is clearly non-limiting in the long-term relative to other events in which only the small capacity Emergency Feedwater System is available. For this reason, an extended analysis of the turbine trip is not necessary. The report will be revised (see Attachment 2) to state that the pressure peak is bounded by other events which challenge the code safety valves, and that the long-term response with continued main feedwater availability is also bounded by events with only the Emergency Feedwater System in operation to provide a secondary heat sink. The Oconee UFSAR does not include an acceptance criterion related to overfilling the pressurizer. The current acceptance criteria are the basis on which the operating license was issued. Duke is not proposing adding this new acceptance criterion.

Question 17

Section 13.0 (Steam Generator Tube Rupture (SGTR)) - Provide the results of a revised analysis methodology to incorporate the following:

a) Assume a loss of offsite power with this event
b) Assume a stuck-open atmospheric dump valve to maximize the radiological consequences.

Response to Question 17

a) The proposed SGTR analysis methodology is based on the current licensing basis which does not assume a loss of offsite power during this event. Duke is not proposing to change the current licensing basis in regard to this assumption.
b) The atmospheric dump valves at Oconee are manual-local valves. Oconee's single failure philosophy was developed prior to the issuance of most of the present day industry standards, and is thus only partially based on the present day standard. Only specific systems are considered for the single failure criterion, and of these systems, a single failure in the EFW system will result in the highest offsite radiological releases during a SGTR event. A failure of a manually-opened valve, such as the atmospheric dump valve, is not in the current licensing basis and is therefore not considered in the proposed SGTR analysis methodology. Duke is not proposing to change the current licensing basis in regard to this assumption.

Question 18

Section 13.0 - Discuss the consequences of the SGTR event assuming the non-safety grade pressurizer heater and spray systems become inoperable.

Response to Question 18

Assuming that the pressurizer heaters are inoperable during an SGTR event will result in a slower repressurization of the RCS following a reactor trip. This will reduce the primary-to-secondary leakage during this portion of the transient, resulting in lower offsite radiological releases. It is therefore conservative to assume that the pressurizer heaters are operable.

During the course of this transient, operators will minimize the RCS subcooled margin to minimize primary-to-secondary leakage. There are three methods that can be used to depressurize the RCS: 1) normal pressurizer spray, 2) auxiliary pressurizer spray, and 3) manual actuation of the pressurizer PORV. The availability of normal pressurizer spray during an SGTR event has been reviewed and approved by the NRC (References: 1) Letter, M. S. Tuckman (Duke), to NRC Document Control Desk, March 27, 1991, G. L. 90-06; 2) Letter, L. A. Wiens (NRC), to J. W. Hampton (Duke), June 9, 1994, SER regarding G. L. 90-06). The least effective method in depressurizing the RCS is normal pressurizer spray. The use of either auxiliary pressurizer spray or the pressurizer PORV will result in a more rapid minimization of the subcooled margin. This will reduce primary-to-secondary leakage during this portion of the transient and result in lower offsite radiological releases. Therefore, the least effective method of depressurizing the RCS, the pressurizer spray valve, is credited.

Question 19

Section 13.0 - Discuss the EOPs available at Oconee that affect the following:

a) Operator isolation of the ruptured steam generator following the SGTR event.

b) Prevention of steam generator overfill, assuming the maximum EFW flow rate.

Response to Question 19

a) The EOPs at Oconee will have operators diagnose that a tube leak has occurred in either the Immediate Manual Actions section or the Subsequent Actions section, depending on whether or not the tube leak has resulted in a reactor trip. This diagnosis will require entry into the SG tube leak section of the EOP, which provides the guidance to mitigate this event. The EOP requires that the RCS be cooled down to a temperature $\leq$ 532°F. After this has been completed the EOP provides guidance to isolate the SG with the tube leak. Isolation refers to stopping both steaming and feeding of the SG with the tube leak. Due to the design of the OTSGs, the tube leak flow can only be minimized (not stopped) as the plant is cooled down and depressurized. Steaming will subsequently be used to prevent SG overfill and to prevent exceeding the tube-to-shell ΔT limits, as necessary. After completion of these initial isolation steps, the EOP refers the operators to the procedure "Control of Secondary Contamination" which will complete the isolation of the SG with the tube leak. This procedure addresses the isolation of drain lines and other possible flowpaths from the secondary side of the SG with the tube leak.

b) EFW is automatically controlled by the safety-grade EFW Control System to a low minimum level setpoint (any RCPs on) once actuated. Manual operator control of EFW to prevent SG overfill is not required, but is included as a backup action in procedures should the control system fail. Due to the SG tube leakage slowly filling the SG, the SG level rapidly exceeds the minimum level setpoint, and EFW is automatically isolated. SG overfill is then a result solely of the continuing SG tube leakage. SG overfill is mitigated by steaming and draining once the overfilled level setpoint is reached.

Question 20

Section 15.0 (Large Steamline Break (SLB)) - Provide discussion in the following areas:

a) Why is the SLB with loss of offsite power very similar to a loss of RCS flow event? Should a SLB with rapid RCS cooldown lead to a more severe DNBR transient?

Response to Question 20 (a)

The SLB with loss of offsite power (LOOP) is very similar to a loss of RCS flow event because in both events the reactor coolant pumps (RCPs) lose power early in the transient. Upon loss of power, the RCPs coast down, resulting in a decrease in core flow. Decreased core flow when reactor power is still high is a DNB concern.

For the SLB with coincident LOOP, the LOOP is assumed to result in the loss of power to the control rod drives, resulting in control rod insertion. In a loss of flow analysis, the initiating event that results in all RCPs coasting down is not assumed to cause control rod insertion. Control rod insertion relies on a reactor trip signal initiated by the Reactor Protection System sometime after the RCPs have actually begun to coast down.

In a loss of flow accident, the RCS pressure remains fairly constant or increases due to the heatup. In the SLB, the cooldown results in the RCS pressure decreasing rapidly, which is a DNB penalty. Due to a finite loop transport time, the SLB induced cooldown of the RCS inventory in the tube bundle does not reach the core before the minimum DNB ratio occurs. Thus, the SLB induced cooldown does not influence the MDNBR during the time period of interest (core inlet temperature remains fairly constant). However, the pressure reduction is immediately sensed in the core region. The combined effect of a flow coastdown and depressurization is a DNB concern.

In summary, the loss of flow event has a delayed insertion of the control rods, and the SLB/LOOP event has a much lower pressure. Both of these effects are DNB penalties, and the limiting event can only be determined by analysis.

b) Should low initial pressurizer level lead to a lower transient pressure and lower DNBR?

<u>Response to Question 20 (b)</u>

For the SLB with offsite power maintained, minimizing the volume of relatively hot pressurizer inventory that drains into the hot leg is conservative with respect to maximizing the cooldown of the core inlet temperature. With a negative moderator temperature coefficient, a greater RCS cooldown maximizes the chances of a post-trip return to power. Sensitivity cases have investigated a high initial pressurizer level coupled with a high initial RCS pressure assumption. The results of these sensitivities indicate that a low initial level with a low initial pressure result in a more severe challenge to DNB.

For the SLB with coincident LOOP, sensitivity cases have been run assuming both high and low initial pressurizer levels. As discussed in the response above, the core inlet temperature does not change before the MDNBR occurs. Thus, system temperature effects associated with varying pressurizer levels do not affect the DNB results. The RCS pressure response has also been shown to be approximately the same regardless of the level assumption during the time period of interest. Thus, the initial pressurizer level assumption is not significant.

c) If a single failure of the EFW control valve is assumed, will a second MDNBR occur later in the transient due to further cooldown of the RCS?

Response to Question 20 (c)

A second MDNBR will not occur later in the transient since there is no return-to-power. Once the High Pressure Injection System (HPI) is actuated and injecting borated water, subcriticality is assured. Boron injection from HPI occurs approximately 85 seconds into the event. The core flood tanks may also inject borated water to prevent a return-to-criticality. The negative reactivity resulting from control rod insertion on reactor trip is sufficient to prevent a return to power in this time period. SLB sensitivity cases have been extended to 10 minutes and confirmed no return to criticality will occur. At 10 minutes operator action to isolate the EFW flow to the affected steam generator is credited to terminate the cooldown.

Question 21

Section 16.0 (Small SLB) - Provide discussion in the following areas:

a) Explain why the acceptance criteria allow fuel failure and the offsite dose within 100 percent of the 10 CFR Part 100 limits for a small steam line break (including an inadvertent opening of a main steam relief valve), which is an incident of moderate frequency.

b) Discuss the consequences of the event assuming failure of the non-safety grade main feedwater system and EFW is needed.

Response to Question 21

a) The offsite dose acceptance criteria in the Oconee UFSAR are the 10 CFR Part 100 dose limits. These were accepted by the NRC when Oconee's operating license was issued. The Standard Review Plan approach of restricting offsite doses for some events to a fraction of the Part 100 limits is not applicable to Oconee. The analyses performed using the DPC-NE-3005-P methodology have demonstrated that no fuel failure will occur for all small steam line breaks, and therefore offsite doses will not be limiting regardless of the acceptance criteria.

b) The small SLB transient is an overpower event that relies on a continued high main feedwater flowrate, well in excess of the full power flowrate, to provide a heat sink that can maintain the core overpower condition without resulting in a reactor trip. If the Main Feedwater System is assumed to fail, then a large mismatch between the core power and the small EFW System heat sink capacity will develop, and the reactor will rapidly trip. In addition, assuming a loss of the Main Feedwater System along with the small steam line break constitutes two initiating events, which is not required. For the small SLB transient, it is the large capacity of the Main Feedwater System which aggravates the plant transient response and causes an approach to the DNB limits. Assuming a loss of the non-safety grade Main Feedwater System would result in a less-limiting transient.

Attachment 3

Revisions and Editorial Corrections to
DPC-NE-3005-P - July 1997

The following revisions and editorial corrections are provided for clarification purposes, and to correct minor errors that have been identified since the submittal of DPC-NE-3005-P on July 30, 1997. One of these revisions is in response to the NRC RAI letter dated April 13, 1998.

1) Page iii: Editorial correction for consistency

2) Page 4-5: Corrected values in the table for the range of initial pressurizer level.

3) Page 5-3: Editorial correction for consistency

4) Page 11-2: Added details of base model nodalization changes to the main steam line and the feedwater boundary condition.

5) Page 12-5: Revised to clarify the modeling of the MFW System.

6) Page 12-6: Revised to state that the long-term response of the turbine trip is bounded by other events.

7) Pages 16-1 and 16-2: Rewritten for clarity.

Table 4-1
Current Initial Condition Ranges and Uncertainties

Key Parameter	Nominal Value	Initial Condition Range	Initial Condition Uncertainty
Reactor Power #	100 %FP (4 RCP) 75 %FP (3 RCP)	98 - 100 %FP 78 - 80 %FP ***	± 2 %RTP
RCS Avg. Temperature #	579 °F for ≥ 15 %FP 532 °F at HZP	578 - 580 °F 527 - 537 °F	± 1 °F + 3 °F, - 2 °F
NR RCS Pressure #	2155 psig	2125 - 2155 psig	± 30 psig
RCS Flow #	~112 %df (4 RCP) 0.747 x 112 %df (3 RCP) 0.49 x 112 %df (2 RCP)	107.5 - 115 %df 74.7 % of 4 RCP range 49 % of 4 RCP range	[ ]
Core Bypass Flow	5.3 %	5 - 7 %	NA **
Pressurizer Level	220 inches	~~220~~ inches 220 - 260	± 25 inches
Core Avg. Fuel Temperature	NA **	1075 - 1250 °F (BOC) 950 - 1150 °F (EOC)	NA **
SG Level	~ 60 %OR (HFP) ~ 69/19 %OR (2/1 RCP) 25 inches XSUR MFW at HZP	55 - 98 %OR 67-98/18-38 %OR 25 inches XSUR MFW	+ 3 %OR, - 5 %OR + 3 %OR, - 5 %OR ± 12.1 inches
SG Pressure	910 psig	This value is chosen to maintain the proper system heat balance	Included in any safety system actuation setpoints
MFW Flow	~1500 lbm/sec/SG	This value is chosen to maintain the proper system heat balance	Included in any safety system actuation setpoints
CFT Inventory	1040 ft^3	1070 - 1010 ft^3	- 40 ft^3 ****
CFT Pressure	600 psig	625 - 575 psig	- 25 psi ****

\# Indicates that the initial condition uncertainty in this parameter is included in the SCD.

* [ ]%df uncertainty applicable for 1 pump in each loop.[ ]%df uncertainty applicable for 2 pumps in one loop and zero pumps in the other loop.

** NA denotes that this value is not applicable since there is not one value that is either repeatable (nominal fuel temperature) or measured (uncertainties).

*** The initial condition range for the 3 RCP UFSAR Chapter 15 analyses assumes that the initial indicated power level is 78-80 % FP

**** These values are for steam line break and not LOCA

5.2.2 VIPRE-01

Should a DNB analysis become necessary, the VIPRE-01 code is used to calculate the minimum DNBR for the startup accident. VIPRE thermal-hydraulic boundary conditions (core heat flux, core inlet flow, core inlet temperature and core exit pressure) are obtained from the RETRAN simulation. The[ ]channel VIPRE model described in Section 2.3 of Reference 5-3 is used to calculate the limiting statepoint local properties and DNBR. The VIPRE analysis will employ the SCD methodology for the startup accident.

5.2.3 SIMULATE-3P

SIMULATE-3P is a core neutronics code used to generate safety analysis physics parameters and three-dimensional core pin power distributions for the startup accident. The conservatism of the physics parameters will be confirmed each cycle as described in Section 5.4 SIMULATE-3P will also be used to calculate the pin power distributions for the accident conditions if a DNBR analysis is necessary. The pin power distributions will then be used to determine if any fuel failures occur.

Core Cooling Capability

5.3 Peak Primary System Pressure and D~~N~~B Analysis

The startup accident analysis presented herein is concerned with maximizing the core heat flux, which therefore maximizes the RCS pressure response. If the predicted heat flux for the peak RCS pressure analysis does not exceed the allowable steady-state heat flux for three-pump operation, then DNB is not of concern for this event. Otherwise a VIPRE-01 analysis is performed to calculate the minimum DNBR.

5.3.1 Initial Conditions

Power Level

An initial critical power level of 1E-9 of the nominal full power level is assumed. This very low initial power level maximizes the power excursion.

The analog ICS is being replaced by an advanced digital ICS. The same modeling philosophy presented for the analog ICS will be used in analyzing the plant response to a dropped rod event with the digital ICS.

The transient response is analyzed with the RETRAN-02 code (Reference 11-1). The DNB analysis is performed with the VIPRE-01 code (Reference 11-2). The core power distribution is analyzed with the SIMULATE-3P code (Reference 11-3). The acceptance criteria for this analysis are to ensure that the minimum DNBR remains above the DNBR limit, and that the pressure in the Reactor Coolant System (RCS) remains below 110% of design pressure. The minimum DNBR is determined using the statistical core design (SCD) methodology. Based on the analysis results, peak RCS pressure is not a concern during this event. The initial conditions and boundary conditions chosen for this analysis are therefore those that will result in the lowest DNBR.

11.1.1 Nodalization

This transient is analyzed using the Oconee two-loop RETRAN model (Reference 11-4). This permits the evaluation of cases with both three and four-pump operation. ~~A junction is added to the base model to connect the steam lines since an asymmetric steam generator response will occur during cases with three-pump operation.~~ (Insert 1 here)

11.1.2 Initial Conditions

Core Power Level

A high initial power level for both three and four RCP operation maximizes the primary system heat flux. The uncertainty for this parameter is incorporated in the SCD methodology.

RCS Pressure

Low initial RCS pressure is conservative for DNBR. The SCD accounts for instrument uncertainty in the pressure indication, but does not account for a controller deadband bias. Nominal pressure less the controller deadband bias is therefore assumed for the initial RCS pressure.

Normalized Scram Curve

A conservatively slow scram curve along with a minimum scram worth is used.

12.3.4 Control, Protection, and Safeguards Systems

Reactor Trip

The reactor trips on the high RCS pressure trip. A conservative trip delay time is assumed. The reactor trip on turbine trip above 28% full power is defeated. This is an additional conservative assumption that is not necessary but is assumed. Future analyses may elect to delete this assumption.

RCS Pressure Control

To maximize the primary system pressure response the pressurizer spray and the PORV are assumed inoperable, and the pressurizer heaters are assumed operable.

Pressurizer Level Control

Due to the short duration of the transient, modeling of makeup/letdown will not significantly affect the results of the analysis, and therefore is not modeled.

Main Feedwater System

Continued post-trip main feedwater flow tends to reduce the secondary system pressure and temperature which results in more primary-to-secondary heat transfer leading to a lower primary system pressure response. Therefore, the Integrated Control System (ICS) initiates an immediate main feedwater ~~is isolated~~ runback on turbine trip to maximize the primary system pressure. The analysis is terminated prior to when the ICS would reestablish main feedwater flow to maintain the post-trip minimum level.

Emergency Feedwater System

No credit is taken for emergency feedwater flow. The ~~limiting conditions~~ results of interest for the transient occur within seconds of the turbine trip before the Emergency Feedwater System can actuate.

Turbine Bypass System

The TBS is assumed to be inoperable to maximize the secondary system pressure and temperature. This will result in reduced primary-to-secondary heat transfer, thus maximizing the primary system pressure response.

12.3.5 Results

The peak primary system pressure case is analyzed for 40 seconds. The sequence of events is shown in Table 12.1. The turbine trip occurs at 0.1 seconds. Following the turbine trip, steam flow to the turbine stops abruptly due to the immediate closure of the turbine stop valves. The mismatch between power generated in the primary system and heat removed by the secondary system results in an increase in the secondary system temperature and pressure. As a result the primary system pressure and temperature increase. The neutron power (Figure 12-1) initially increases slightly due to the positive reactivity feedback associated with the increasing RCS pressure, which exceeds the negative reactivity feedback associated with the increasing RCS temperature. The RCS pressure (Figure 12-2) and the hot and cold leg temperatures (Figure 12-3) increase almost instantly due to the reduction in primary-to-secondary heat transfer. The pressurizer level (Figure 12-4) increases due to the expansion of the coolant.

The high RCS pressure trip setpoint is reached at 3.49 seconds after turbine trip, with the actual reactor trip occurring at 3.99 seconds including the RPS delay time. The RCS pressure continues to increase following the reactor trip and reaches a maximum actual pressure of 2503 psig at 7.5 seconds after the turbine trips. The PSVs do not lift. A few seconds after the reactor trips on high RCS pressure the RCS pressure begins to decrease. This results from decreasing reactor power and decreasing main steam pressure (Figure 12-5) resulting from the lifting of the main steam safety valves. The peak primary pressure occurs at the bottom of the reactor vessel (Figure 12-6). At 7.4 seconds after turbine trip, the pressure at the bottom of the reactor vessel reaches a maximum value of 2590.4 psig. This is within the acceptance criterion of 2750 psig.

(Insert 1 here)

12.3.6 RETRAN-3D Comparison

The RETRAN-02 and RETRAN-3D results comparisons are shown in Figures 12-1 to 12-6. The results are in good agreement with the exception of the primary system pressure. A difference of 13 psi (approximately 4%) between the RETRAN-02 and RETRAN-3D primary pressure predictions develops in the first 8 seconds of the transient. Pressure is very sensitive to rapid increases in pressurizer level, and in this case the deviation in the pressurizer level is less than 2 inches. This level deviation results from a small difference in primary-to-secondary heat transfer beginning at around 3 seconds when the main steam safety valves begin to lift. This is attributed

16.0 SMALL STEAM LINE BREAK

A small steam line break can be initiated from either a control system failure in which valves in the main steam line fail open or a mechanical failure of the steam line piping itself. Regardless of which type of failure occurs, the increased steam flow will cause both steam generators to depressurize until they are separated by turbine stop valve closure on turbine trip. The transient response is an overcooling event that results in an increase in power level. The system response is determined by the break size, the moderator temperature coefficient, and the Integrated Control System (ICS) assumption (manual or automatic). The most adverse combination of these conditions is analyzed to determine the worst RCS overcooling and power excursion, which should be the limiting case for DNB and centerline fuel melt (CFM). The limiting cases do not result in a reactor trip due to the reduction in reactor vessel downcomer temperature affecting the excore flux channels. Avoiding a reactor trip will result in a new steady-state condition at an elevated power level. The system response is simulated with RETRAN-02 (Reference 16-1). Both full power four-pump and part-power three-pump cases are analyzed. Analyses are performed both with and without credit for the high steam generator level trip of the main feedwater pumps. The RETRAN analysis provides the input for the DNB and CFM analyses.

The acceptance criteria for this analysis are to ensure that acceptable fuel damage limits are not exceeded, and that the offsite doses will be within 100% of the 10CFR100 limits. The fuel damage evaluation includes both DNB and CFM. The minimum DNBR is determined using the Statistical Core Design (SCD) methodology and the VIPRE-01 core thermal-hydraulic code (Reference 16-2). CFM limits are determined using the TACO-3 fuel pin code (Reference 16-3).

16.1 RETRAN-02 Analysis

16.1.1 Nodalization

For the four-pump operating condition, the system response is symmetric and can be analyzed using the single-loop RETRAN-02 Oconee base model (Reference 16-4). The three-pump operating condition is asymmetric and requires the use of the two-loop RETRAN-02 Oconee base model. ~~A steam chest junction is added to the two-loop base model to connect the steam lines upstream of the turbine for modeling the simultaneous depressurization of both generators~~

(Insert 1 here)

~~prior to turbine trip. This junction closes on turbine trip when the turbine stop valves close.~~

[ ]

16.1.2 Initial Conditions

<u>Power Level</u>

A high initial power level for four- and three-pump operation maximizes the primary system heat flux. The uncertainty for this parameter is incorporated in the SCD limit.

<u>RCS Pressure</u>

Low initial RCS pressure is conservative. The uncertainty for this parameter is incorporated in the SCD limit.

<u>Pressurizer Level</u>

Sensitivity cases are performed to ensure that a conservative pressurizer level is assumed for the conditions analyzed.

<u>RCS Temperature</u>

High initial average temperature is conservative with the uncertainty for this parameter incorporated in the SCD limit.

<u>RCS Flow</u>

Low initial flow is conservative. The uncertainty associated with this parameter is incorporated in the SCD limit.

<u>Core Bypass Flow</u>

A high core bypass flow is assumed to minimize the coolant flow along the fuel rods.

Inserts as Marked on Previous Pages

Page 11-2 - Insert 1

[PROPRIETARY INFORMATION]

Page 12-6 - Insert 1

Since the high flow capacity Main Feedwater System remains available following a turbine trip event, other transients which rely on the smaller capacity Emergency Feedwater System bound the turbine trip transient in the longer-term. Therefore, only the short-term results are presented.

Page 16-1 - Insert 1

[PROPRIETARY INFORMATION]