DUKE ENERGY®

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~~PROPRIETARY INFORMATION~~

~~WITHHOLD FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390~~

RA-18-0098 10 CFR 50.90

July 20, 2018

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

Duke Energy Carolinas, LLC
Oconee Nuclear Station (ONS), Units 1, 2, and 3
Docket Numbers 50-269, 50-270, and 50-287
Renewed Facility Operating License Nos. DPR-38, DPR-47, and DPR-55

Subject: Response to Request for Additional Information Related to Proposed Revisions to the Updated Final Safety Analysis Report Section for the Standby Shutdown Facility; License Amendment Request No. 2017-03, Supplement 1 Revision

Duke Energy Carolinas, LLC (Duke Energy) submitted a License Amendment Request (LAR), which proposes to revise the Updated Final Safety Analysis Report (UFSAR) to allow off-nominal success criteria for a Standby Shutdown Facility (SSF) mitigated Turbine Building (TB) flood event occurring when the Oconee Unit(s) are not at nominal full power conditions, on October 20, 2017. By email dated May 1, 2018, NRC requested Duke Energy to respond to a Request for Additional Information (RAI) associated with the LAR. This response replaces the original RAI response provided by letter dated June 15, 2018, in its entirety. The enclosure and attachments provide the requested information.

Responses to many of the RAI questions contain information that is proprietary to Duke Energy. Within Enclosure 2, Duke Energy proprietary information is identified by brackets. In accordance with 10 CFR 2.390, Duke Energy requests that this information be withheld from public disclosure. Attachment 3 contains an Affidavit attesting to the proprietary nature of the information in Enclosure 2. The proprietary information is owned by Duke Energy and has substantial commercial value that provides a competitive advantage. Enclosure 1 contains a non-proprietary [redacted] version of this content.

The responses to the RAIs do not affect the conclusions of the No Significant Hazards Consideration provided in the October 20, 2017 LAR. Inquiries on this proposed amendment request should be directed to Boyd Shingleton, ONS Regulatory Affairs Group, at (864) 873-4716.

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NRR

Enclosure 2 to this letter contains ~~proprietary information.~~
~~Withhold from Public Disclosure Under 10 CFR 2.390.~~
Upon removal of Enclosure 2, this letter is uncontrolled.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 20, 2018.

Sincerely,

J Ed Burchfield Jr

J. Ed Burchfield, Jr.
Vice President
Oconee Nuclear Station

Enclosures:
1) Duke Energy Response to NRC Request for Additional Information (Non-Proprietary)
2) Duke Energy Response to NRC Request for Additional Information (Proprietary)

Attachments:
1) UFSAR Marked-Up Pages
2) UFSAR Retyped Pages
3) Duke Energy Affidavit

cc w/enclosures and attachments:

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Bureau of Land and Waste Management
Department of Health & Environmental Control
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ATTACHMENT 3

DUKE ENERGY AFFIDAVIT

AFFIDAVIT OF JOSEPH DONAHUE

1. I am a Vice President of Duke Energy Carolinas, LLC (Duke Energy), and as such have the responsibility of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear plant licensing and am authorized to apply for its withholding on behalf of Duke Energy.

2. I am making this affidavit in conformance with the provisions of 10 CFR 2.390 of the regulations of the Nuclear Regulatory Commission (NRC) and in conjunction with Duke Energy's application for withholding which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke Energy in designating information as proprietary or confidential. I am familiar with the Duke Energy information contained in Enclosures 1 and 2 of Oconee License Amendment Request (LAR) 2017-03 Supplement 1 Revision which responds to an NRC Request for Additional Information associated with the October 20, 2017, LAR.

4. Pursuant to the provisions of paragraph (b) (4) of 10 CFR 2.390, 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 Energy and has been held in confidence by Duke Energy and its consultants.

   ii. The information is of a type that would customarily be held in confidence by Duke Energy. The information consists of analysis methodology details that provide a competitive advantage to Duke Energy.

   iii. The information was transmitted to the NRC in confidence and under the provisions of 10 CFR 2.390, 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 from public disclosure in this submittal is that which is marked by brackets in the proprietary version of Enclosure 2 to this submittal. This information is consistent with marked proprietary information in NRC-approved Duke Energy methodology reports DPC-NE-3000-PA and DP-NE-3003-PA referred to in Attachment 2 of the LAR 2017-74, dated October 20, 2017. This information enables Duke Energy to:

      (a) Support license amendment and Technical Specification revision requests for its Oconee reactors.
      (b) Perform transient and accident analysis calculations for Oconee.

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

(a) Duke Energy uses this information to reduce vendor and consultant expenses associated with supporting operation and licensing of nuclear power plants.
(b) Duke Energy can sell the information to nuclear utilities, vendors, and consultants for the purpose of supporting operation and licensing of nuclear plants.
(c) The subject information could only be duplicated by competitors at similar expense incurred by Duke Energy.

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

Joseph Donahue affirms that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth herein are true and correct to the best of his knowledge.

Joe Donahue

Subcribed and sworn to me: July 12, 2018
Date

Notary Public

My Commission Expires: June 1, 2026

LISA SALVADOR NOTARY PUBLIC SOUTH CAROLINA

Lisa Salvador
NOTARY PUBLIC
State of South Carolina
My Commission Expires
June 1, 2026

ENCLOSURE 1

DUKE ENERGY RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
[NON-PROPRIETARY]

Duke Energy Response to NRC Request for Additional Information

NRC RAI Summary Introduction

By letter ONS-2017-074 dated October 20, 2017 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17299A114), Duke Energy Carolinas, LLC (the licensee) applied for license amendments to Renewed Facility Operating Licenses DPR-38, DPR-47, and DPR 55, for the Oconee Nuclear Station, Units 1, 2, and 3 (Oconee), respectively. In its License Amendment Request (LAR) No. 2017-03, the licensee requested that the Updated Final Safety Analysis Report (UFSAR) be revised to allow (1) off nominal success criteria for a Standby Shutdown Facility (SSF)-mitigated Turbine Building flood (TBF) event occurring when the Oconee units are not at nominal full power conditions and (2) use of the Main Steam (MS) Atmospheric Dump Valves (ADVs) to enhance SSF mitigation capabilities. In March 2018, the NRC staff completed a regulatory audit using an internet-based portal from the NRC Headquarters office in Rockville, MD. The audit plan is available in ADAMS at Accession No. ML18032A461. In order to complete its review, the staff developed the following requests for additional information (RAIs).

RAI-1 (Reactor Systems Branch (SRXB))

The following RAIs are related to the licensee's RETRAN analysis (e.g., methods, modelling assumptions, model modifications, etc.) and are needed to give the staff confidence that the proposed UFSAR acceptance criteria are met for maintaining the reactor in a safe shutdown condition when using the SSF to mitigate a TBF event.

RAI-1.A

Page 2 of the Enclosure to LAR 2017-03 states, "As the flood height in the turbine building increases, the flooding results in a reactor/turbine trip and a loss of both main and emergency feedwater systems." However, on page 11, it states, "For example, an overheating case may assume maximum decay heat, a delayed reactor trip from the Reactor Protection System, minimum EFW flow rates, and neglect modeling secondary system steam loads and RCS (Reactor Coolant System) ambient heat losses to minimize primary-to-secondary heat transfer and maximize the post-trip RCS overheating response." The staff requests the licensee to explain why Emergency Feedwater (EFW) flow is credited (which the staff understands to be a non-conservative assumption for an overheating event) when the initiating event is a loss of both main and EFW systems. In addition, the staff requests the licensee to provide sequence-of-events tables for the limiting cases (i.e., nominal full power, low decay heat, and high decay heat with low initial temperature), including items such as operator actions and availability of systems (e.g., EFW, SSF letdown line, SSF auxiliary service water, etc.).

Duke Energy Response

The statement on page 2 of the Enclosure to LAR 2017-03 stating "As the flood height in the turbine building increases, the flooding results in a reactor/turbine trip and a loss of both main and emergency feedwater systems," refers to a gradual loss of the stated equipment. The statement on page 11, "For example, an overheating case may assume maximum decay heat, a delayed reactor trip from the Reactor Protection System, minimum EFW flow rates, and neglect modeling secondary system steam loads and RCS (Reactor Coolant System) ambient heat losses to minimize primary-to-secondary heat transfer and maximize the post-trip RCS overheating response," is a generalized statement of how an overheating event would be modeled, including how EFW would be modeled while available.

The Turbine Building Flood event results in a gradual loss of normal and emergency equipment as the flood water rises to the elevations of the equipment inside the Turbine Building. Normal plant equipment is modeled in the analyses until it is lost. For example, the Condensate Booster Pumps in the Feedwater System are located on the basement floor of the Turbine Building and flood almost immediately, resulting in a rapid loss of main feedwater at event initiation. Motor Driven Emergency Feedwater equipment, located at a higher elevation, is not lost until approximately 13 minutes into the event. EFW is therefore modeled with a minimum or maximum flow capacity during the first 13 minutes depending on whether the T-H analyses is an overheating or overcooling case, respectively. Also, overheating cases assume a maximum EFW fluid temperature of 130°F, while overcooling cases assume a minimum EFW fluid temperature of 60 °F.

Sequence of events tables are provided below for the limiting cases relative to the success criteria associated with this event.

For the nominal core cooling success criteria which requires that a sufficient level in the pressurizer be maintained to ensure long term core cooling, a review of the Region 5 Nominal Operation Conditions RETRAN analyses was performed to determine which case(s) had the lowest pressurizer level response during the 72-hour long event. Cases 70.max and 70.min result in the lowest pressurizer level response for the Region 5 Nominal Operation Conditions analyses performed for this event. RAI-1.A Table 1 shows the sequence of events for Case 70.max which is representative of both cases. The time at which the minimum pressurizer level occurs for these cases is the same. The only difference between the cases is the RC Makeup pump flow (maximum or minimum) which starts after the time at which the minimum pressurizer level occurs. This sequence of events table reflects both equipment availability and operator actions.

For the off-nominal core cooling success criteria (low decay heat) which requires that a minimum water level above the reactor core shall be maintained and conditions that support the formation of natural circulation flow shall be established, Case r2.min.low.dcy results in the lowest pressurizer level response for Regions 1 and 2 Off-Nominal Operation Conditions analyses during the 72-hour long event. Table RAI-1.A Table 2 shows the sequence of events for this case. This table reflects both equipment availability and operator actions.

For the off-nominal core cooling success criteria (low RCS temperature/high decay heat) which requires that a minimum water level above the reactor core be maintained, conditions that support natural circulation be established, and that liquid relief through the pressurizer code safety valves is prevented, Case 250f results in the most limiting transient conditions for the Region 4 Off-Nominal Operation Conditions analyses. This case reflects the longest period of time during which a water-solid condition is present in the pressurizer. Table RAI-1.A Table 3 shows the sequence of events for this case. This table reflects both equipment availability and operator actions.

RAI-1.A Table 1 Sequence of Events
Region 5 - Case 70.max.out

Event	Time (seconds)
Event start	0.0
Loss of main feedwater due to flooding	0.1
Reactor trip on loss of main feedwater	0.1
Turbine Trip on reactor trip	0.3
Pressurizer heaters on/off per normal automatic operation	4.3
Turbine Bypass Valves open MSRVs Open	4.8
3 Pump EFW available	20.1
3 Pump EFW begins	~146
All MSRVs reseated	30.9
SSRH isolates on both steam lines	60.1
TDEFWP fails	495
Operators trip three RCPs Operators provide maximum flow to SGs	600
Operators stop feeding SGs due to low RCS temperature	660
MDEFWPs fail (Loss of all EFW) Operator Dispatched to the SSF	792
Operators trip remaining RCP	972
Turbine Bypass System Unavailable Operators isolate AS, CSAE, ESAE, and TDEFWP steam loads	1200
Normal RCS letdown lost Operators secure HPI (normal makeup, RCP seal injection and HPI nozzle warming flow terminated)	1428
Operators begin SSF ASW flow to SGs SSF operator begins raising SG levels to nat. circ. setpoint	1632
RCP seal return isolated	2328
SSF RC Makeup pump started SSF letdown line operation begins	2628
Normal pressurizer heaters are assumed to be unavailable SSF powered pressurizer heaters available	14400
SG natural circulation levels achieved	~69200
MFW inventory begins flashing	~200000
End of simulation	259200

RAI-1.A Table 2 Sequence of Events
Region 2 - Case r2.min.low.dcy.out

Event	Time (seconds)
Event start	0.0
Loss of main feedwater due to flooding	0.1
Reactor trip on loss of main feedwater	0.1
Turbine Trip on reactor trip	0.3
Pressurizer heaters on/off per normal automatic operation	4.0
Turbine Bypass Valves open MSRVs Open	4.2
3 Pump EFW available	20.1
All MSRVs reseated	41.0
SSRH isolates on both steam lines	60.1
3 Pump EFW begins	~475
TDEFWP fails	495
Operators trip three RCPs Operators stop EFW to SGs due to overcooling	600
Operators stop feeding SGs due to decreasing RCS temperature	690
MDEFWPs fail (Loss of all EFW) Operator Dispatched to the SSF	792
Operators trip remaining RCP	972
MFW Inventory begins flashing	~1080
Turbine Bypass System unavailable Operators isolate AS, CSAE, ESAE, and TDEFWP steam loads	1200
Normal RCS letdown lost Operators secure HPI (normal makeup, RCP seal injection and HPI nozzle warming flow terminated)	1428
Operators begin SSF ASW flow to SGs SSF operator begins raising SG levels to nat. circ. setpoint	1632
RCP seal return isolated	2328
SSF RC Makeup pump started SSF letdown line operation available	2628
Normal pressurizer heaters are assumed to be unavailable SSF powered pressurizer heaters available	14400
CFT injection occurs	52103
End of simulation	259200

RAI-1.A Table 3 Sequence of Events
Region 4 - Case 250f.out

Event	Time (seconds)
Operators insert control rods at EOC shutdown conditions	0.1
Operators maintain RCS at normal Mode 3 conditions > 525°F	0-1200
Unit Cooldown begins at 100°F/hr	1200.1
RCS T-cold at 250°F, TBF event begins	13400
Loss of Main Feedwater due to flooding Operators close Turbine Bypass valves	13400
2 Pump EFW begins	13566
MDEFWPs fail (Loss of all EFW) Operator Dispatched to the SSF	14192
Operators trip all RCPs	14372
Normal RCS letdown lost RCP seal injection fails open	14828
Operators begin SSF ASW flow to SGs	15032
Pressurizer PORV begins cycling at LOW setpoint	15249
Operators secure HPI (normal makeup, RCP seal injection and HPI nozzle warming flow terminated) RCP seal return isolated SSF RC Makeup pump started SSF powered pressurizer heaters on	16028
SSF letdown used to control RCS pressure at ~450 psig	~16102
SG natural circulation levels achieved	~17360
RCS T-cold at 350°F Pressurizer PORV setpoint set to HIGH SSF letdown used to control RCS pressure at ~1600 psig	18549
Lowest lifting MSRVs begin cycling	34826
Pressurizer water-solid	~35810
End of simulation	273000

RAI-1.B

The model modifications needed for the RCS and pressurizer ambient heat losses resulted in the use of an extremely large heat transfer coefficient on the inside pipe wall surfaces, with the actual heat transfer to the environment being controlled on the outside surfaces. The use of a large heat transfer coefficient will result in the inside wall surface temperature and fluid/saturation temperature being very close together and will affect the condensation rate (and resulting RCS pressure), as condensation is based on the temperature difference (ΔT). The staff requests the licensee to explain why this is an acceptable modelling method for both overheating and overcooling events and how the results would be different if the inside wall heat transfer coefficient was calculated by RETRAN.

Duke Energy Response

Two of the cases (overheating and overcooling) performed in the TBF thermal-hydraulic analysis are rerun in which RETRAN is allowed to select the heat transfer coefficients (HTCs) on the inside of the heat conductors exposed to the containment environment versus the user specified value of 9000 Btu/hr-ft2-°F (See discussions on pages 68 and 76 of the RETRAN analysis). These cases are renamed as follows:

Original Case Name	New Case Name (RETRAN Selected HTCs)
eoc.min (overheating case)	eoc.min.pzr.htc.sens
85.min (overcooling case)	85.min.rcs.pzr.htc.sens

The resultant pressurizer heat transfer coefficients and conductor inside surface temperatures are tabulated below and compared to the original cases for both the vapor region and liquid region of the pressurizer at the time of event initiation:

	Pressurizer Vapor Region	
Case Name	Pressurizer Inside Heat Transfer Coefficient Btu/hr-ft2-°F	Conductor Inside Surface Temperature (°F)
eoc.min	9000	~649
eoc.min.pzr.htc.sens	~1980-2580*	~649
85.min	9000	~649
85.min.rcs.pzr.htc.sens	~2060-2720*	~649

* average values for conductors located in the vapor region

	Pressurizer Liquid Region	
Case Name	Pressurizer Inside Heat Transfer Coefficient Btu/hr-ft2-°F	Conductor Inside Surface Temperature (°F)
eoc.min	9000	~622-649*
eoc.min.pzr.htc.sens	5	~502-529*
85.min	9000	~620-649*
85.min.rcs.pzr.htc.sens	5	~500-530*

* bottom pressurizer conductor at lowest temperature, with increasing temperatures as conductor elevation increases

The above data shows that there is little difference in the pressurizer conductor inside surface temperatures in the vapor region for the cases in which RETRAN selects the heat transfer coefficients. Even though there is a sizable difference in the actual HTC values, it is apparent that the RETRAN selected values are large enough that adequate heat transfer occurs between the vapor region and the conductor to match the ambient losses from the outside of the conductors without developing a large temperature differential. In the vapor region, RETRAN-3D is selecting the Chun-Seban correlation for condensation on vertical surfaces; RETRAN-3D heat transfer Mode 22.

The opposite is true for the conductors located in the liquid region of the pressurizer. With stagnant flow conditions present in the pressurizer, RETRAN defaults to a minimum HTC value of 5 Btu/hr-ft2-°F for the liquid region conductors. This HTC value is the lower bound for the

Dittus-Boelter forced convection correlation in subcooled liquid; RETRAN-3D heat transfer Mode 1. This results in a large temperature differential between the conductor inner surface temperature and the pressurizer fluid temperatures ranging from ~60°F-130°F. Based on engineering judgement, this temperature differential appears to be exceedingly large. A review of other conductor surface temperatures outside of the pressurizer region do not show this large of a difference between the volume fluid temperatures and the associated conductor surface temperatures.

A fixed heat transfer coefficient was chosen at the inside surface to more realistically model the conditions in the pressurizer. Since some of the cases performed in the TBF thermal-hydraulic evaluation reach near stagnant flow conditions in the RCS, it was also decided to do the same modeling for those conductors in which ambient losses were being modeled to prevent what was thought to be an unrealistic differential temperature developing between a volume fluid temperature and its associated conductor surface temperature.

RAI-1.B Figures 1 through 5 show a comparison of the transient response for the eoc.min cases (overheating event) in which a user defined heat transfer coefficient is used vs. allowing RETRAN to select the HTCs. RAI-1.B Figures 1 and 4 (RCS pressure and RCS subcooling) show that there is a small difference in the transient response during the first ~2000 minutes of the event. The minimum RCS pressure response (Figure 1) during this time is lower for the case in which RETRAN selects the HTCs by ~130 psi, which is reflected in a lower minimum subcooling margin (Figure 4) of ~26°F (~10°F lower). After this time, the pressurizer re-saturates at a more rapid rate when RETRAN determines the HTCs, resulting in a more rapid repressurization of the RCS by 2000 minutes. After this time, there is a negligible difference for the remainder of the transient.

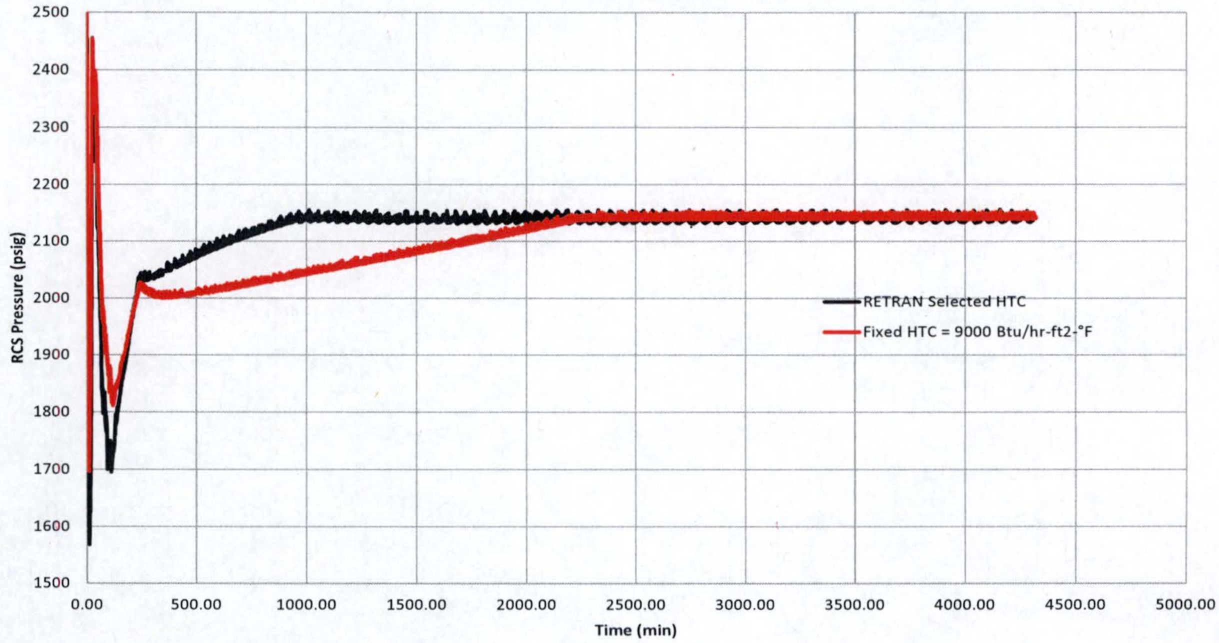
RAI-1.B Figures 2, 3, and 5 show the pressurizer level, core inlet temperature, and SG pressure response for the comparison cases. These figures show there is a negligible difference in these parameters for the duration of the event.

RAI-1.B Figures 6 through 10 show a comparison of the transient response for the 85.min cases (overcooling event) in which a user defined heat transfer coefficient is used vs. allowing RETRAN to select the HTCs. RAI-1.B Figures 6 and 9 (RCS pressure and RCS subcooling) show that there is a difference in the transient response during the first ~300 minutes of the event for these parameters. The minimum RCS pressure response (Figure 6) during this time is lower for the case in which RETRAN selects the HTCs by ~270 psi, which is reflected in a lower minimum subcooling margin (Figure 9) of ~45°F (~17°F lower). After this time, the pressurizer re-saturates at a slower rate when RETRAN determines the HTCs, resulting in a reduced repressurization of the RCS by 300 minutes. After this time, there is a negligible difference for the remainder of the transient.

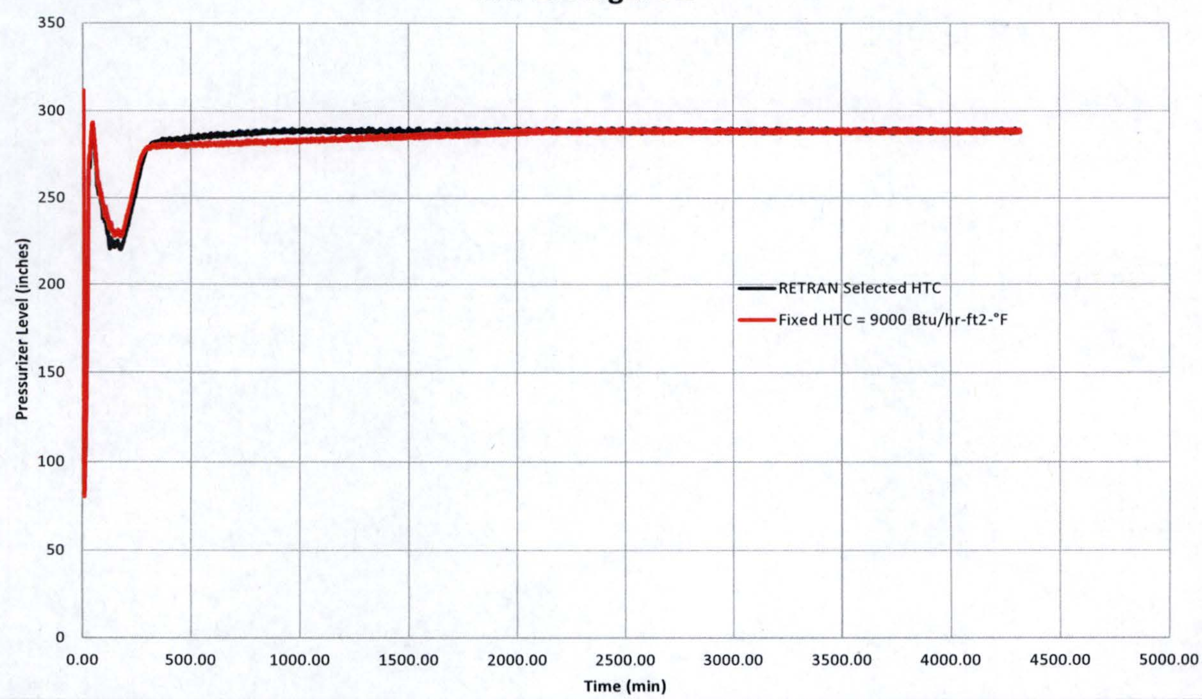
RAI-1.B Figures 7, 8, and 10 show the pressurizer level, core inlet temperature, and SG pressure response for the comparison cases. These figures show there is a negligible difference in these parameters for the duration of the event.

The results of these cases show that the success criteria associated with this event would not be challenged when using either a fixed HTC or allowing RETRAN to determine the HTC.

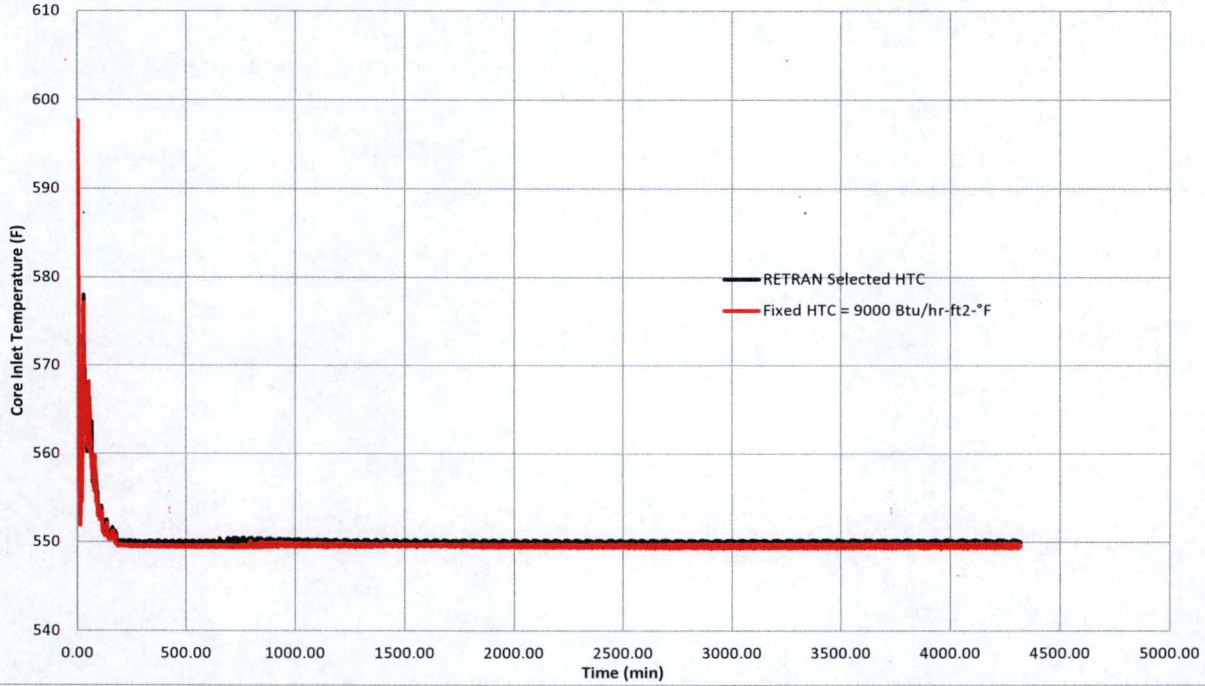
Turbine Building Flood Analysis
Region 5 Case eoc.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 1



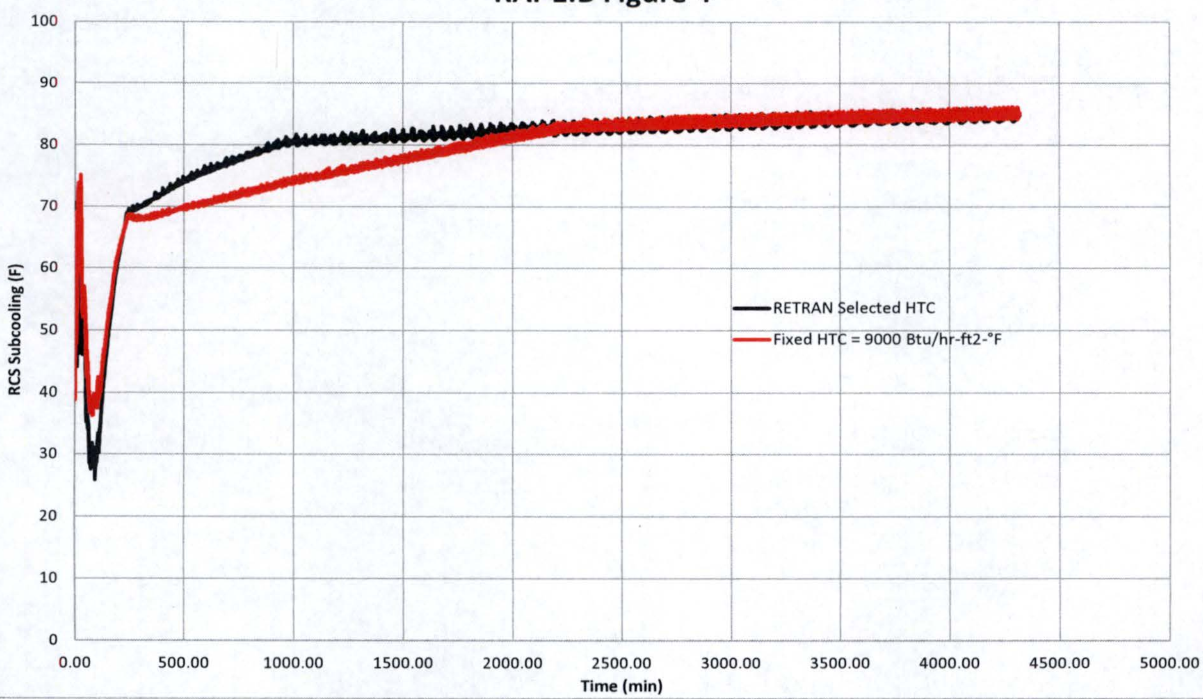
Turbine Building Flood Analysis
Region 5 Case eoc.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 2

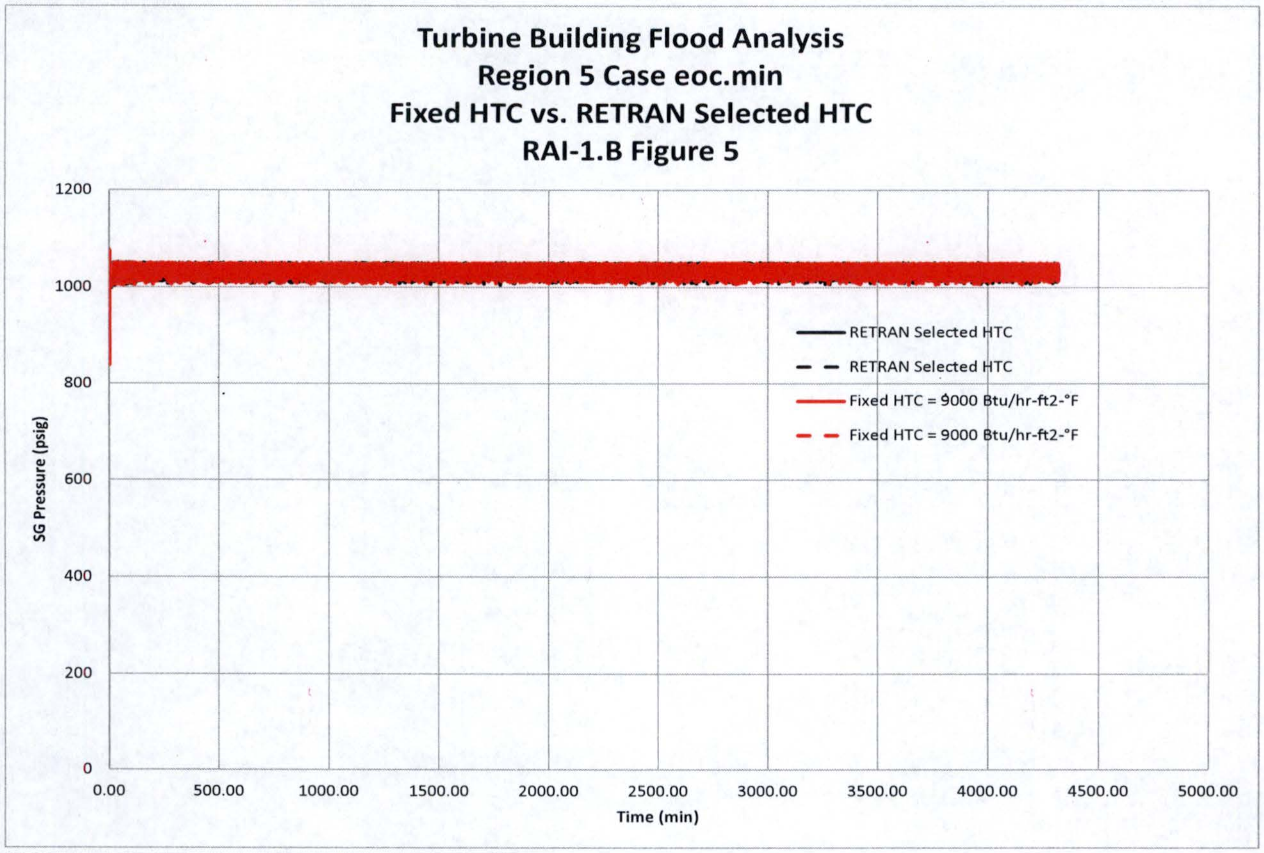


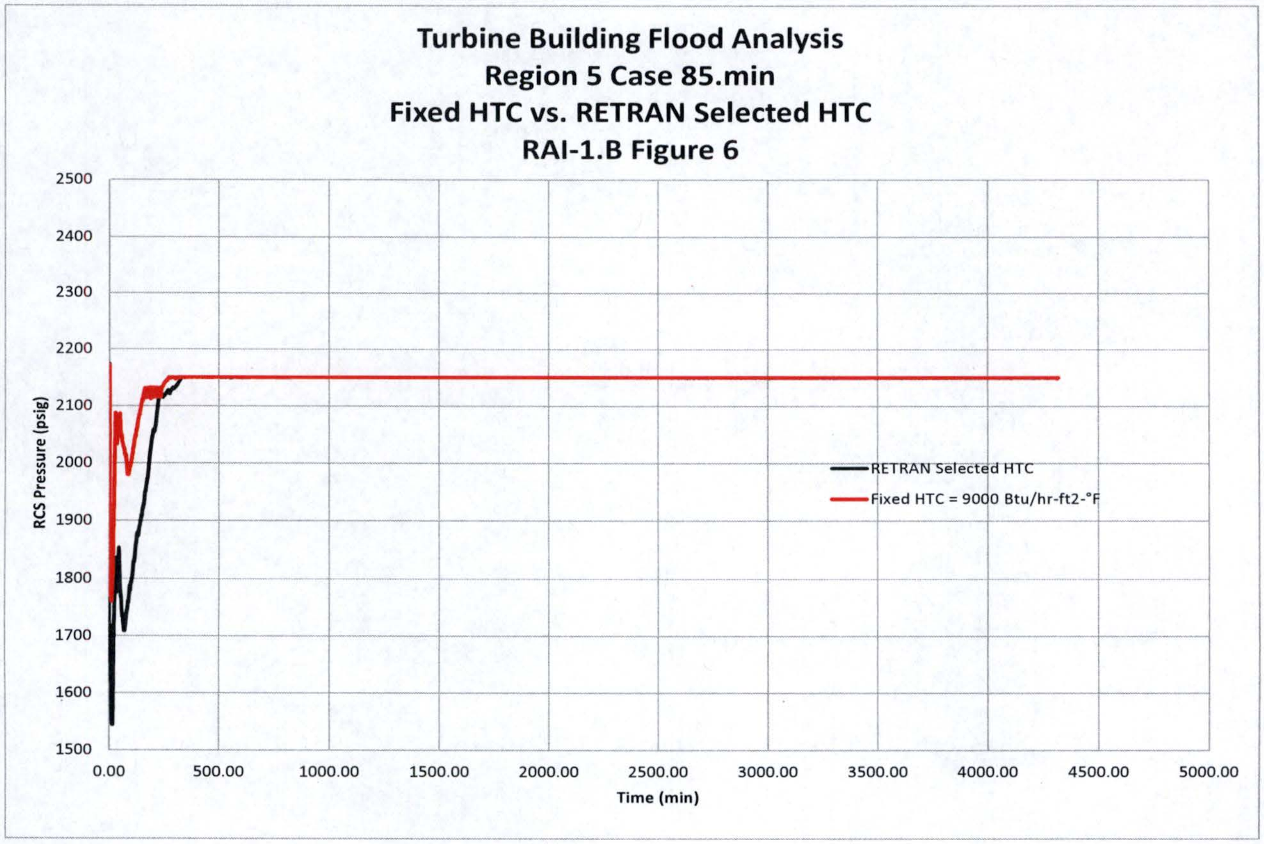
Turbine Building Flood Analysis
Region 5 Case eoc.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 3

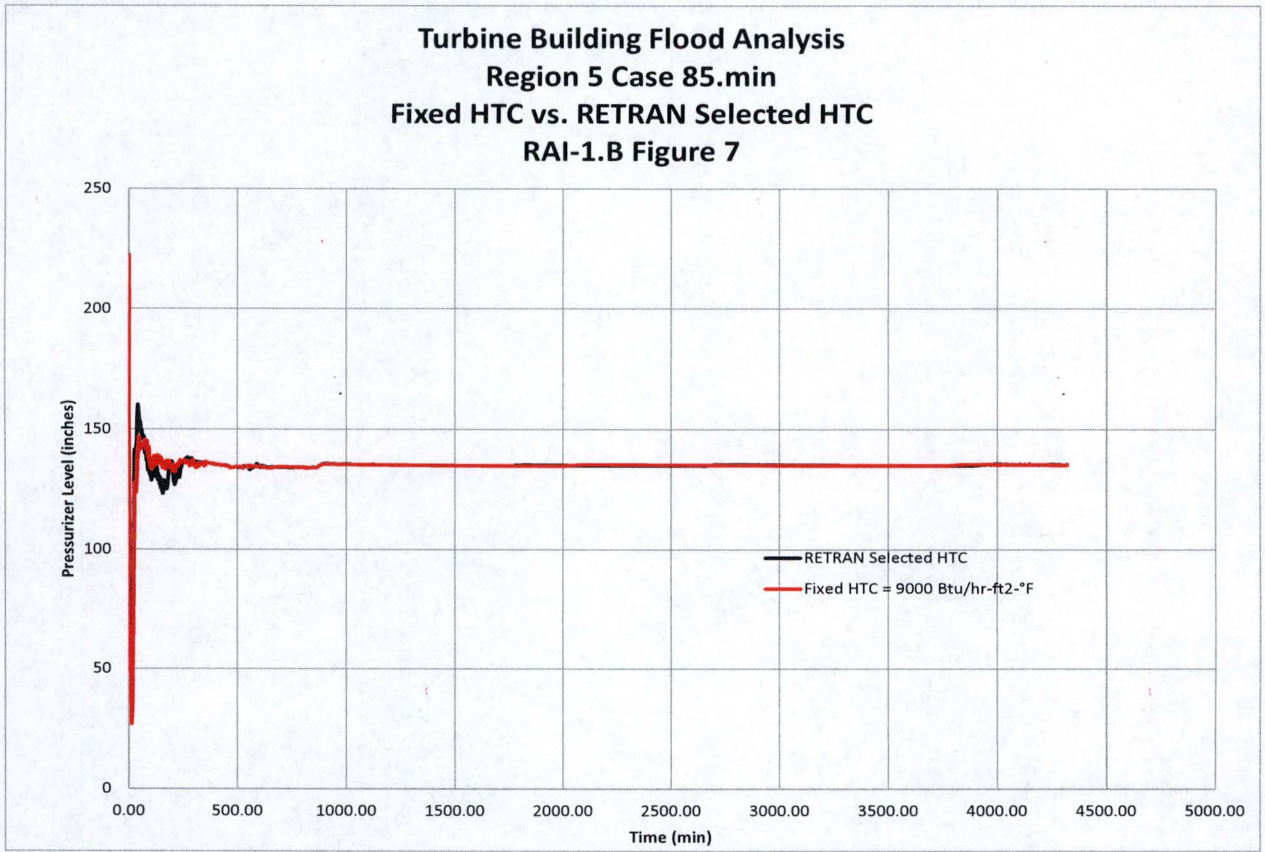


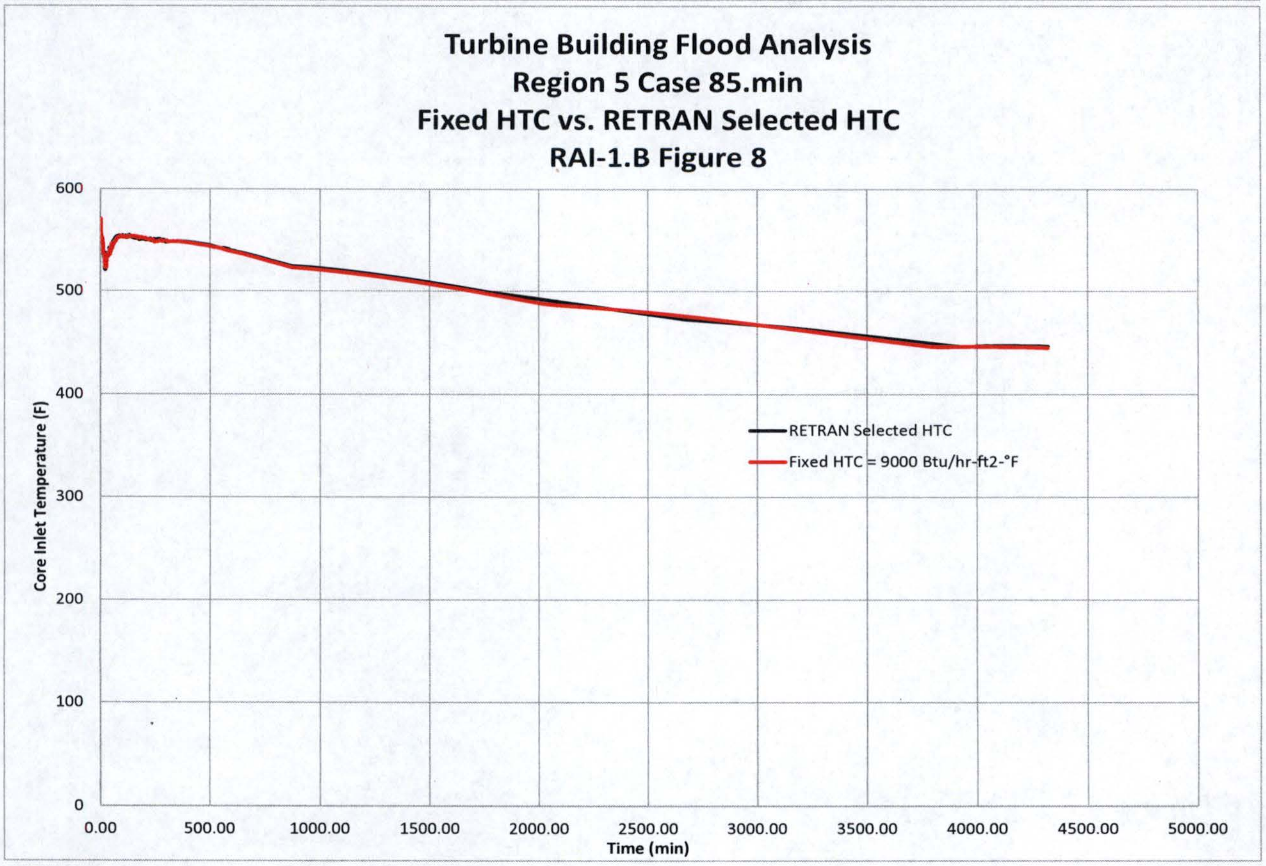
Turbine Building Flood Analysis
Region 5 Case eoc.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 4

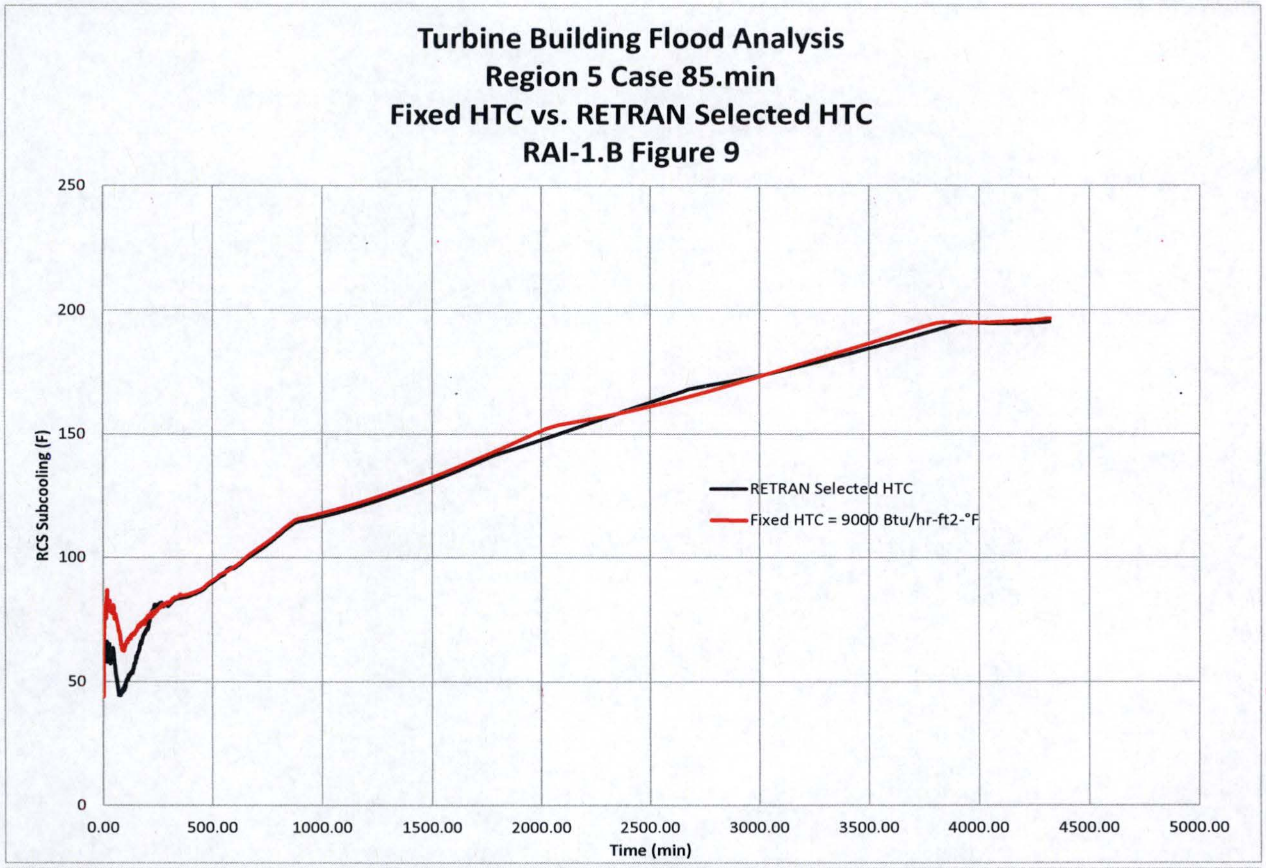


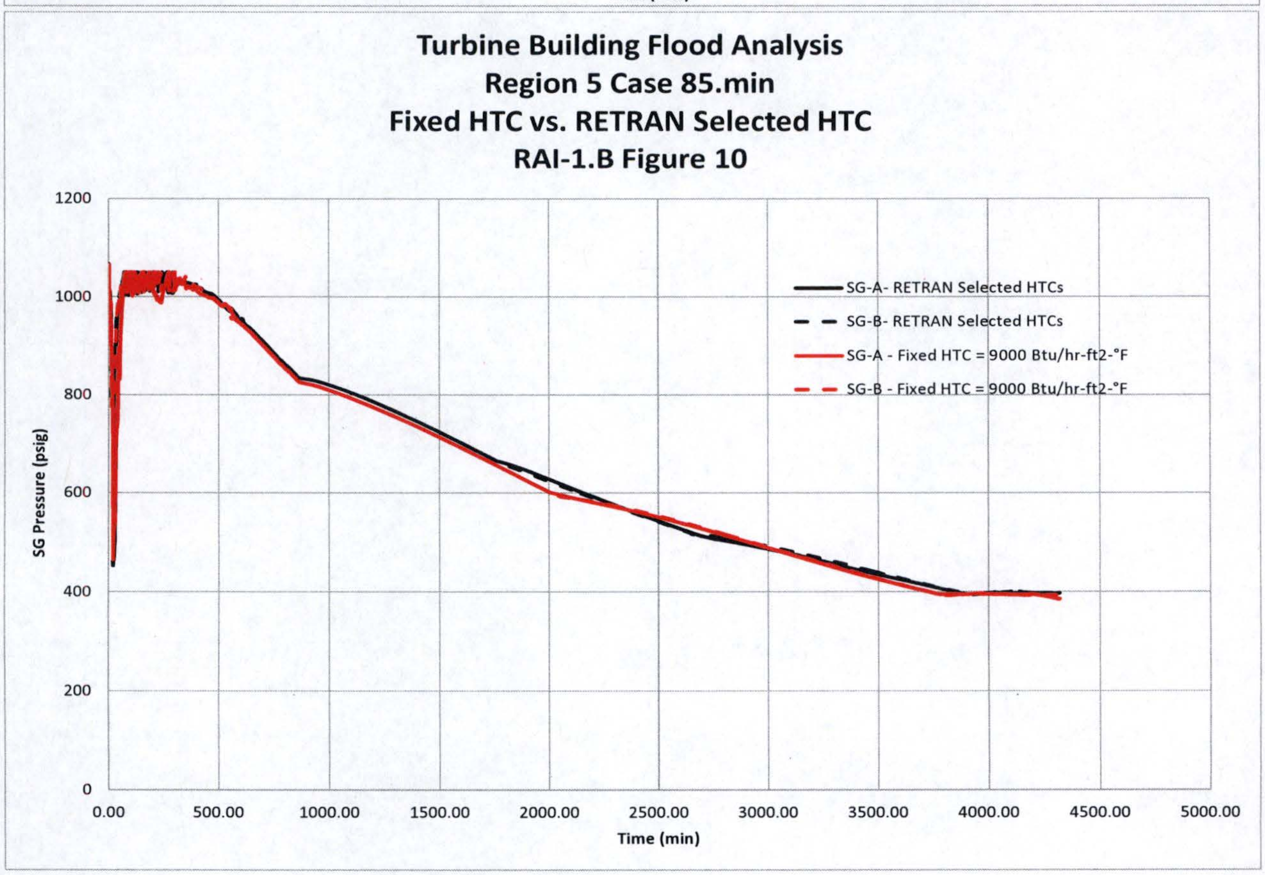

Turbine Building Flood Analysis
Region 5 Case eoc.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 5
SG Pressure (psig)
Time (min)
RETRAN Selected HTC
RETRAN Selected HTC
Fixed HTC = 9000 Btu/hr-ft2-°F
Fixed HTC = 9000 Btu/hr-ft2-°F
0
200
400
600
800
1000
1200
0.00
500.00
1000.00
1500.00
2000.00
2500.00
3000.00
3500.00
4000.00
4500.00
5000.00


Turbine Building Flood Analysis
Region 5 Case 85.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 6
RCS Pressure (psig)
Time (min)
RETRAN Selected HTC
Fixed HTC = 9000 Btu/hr-ft2-°F
1500
1600
1700
1800
1900
2000
2100
2200
2300
2400
2500
0.00
500.00
1000.00
1500.00
2000.00
2500.00
3000.00
3500.00
4000.00
4500.00
5000.00


Turbine Building Flood Analysis
Region 5 Case 85.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 7
Pressurizer Level (inches)
Time (min)
RETRAN Selected HTC
Fixed HTC = 9000 Btu/hr-ft2-°F
0
50
100
150
200
250
0.00
500.00
1000.00
1500.00
2000.00
2500.00
3000.00
3500.00
4000.00
4500.00
5000.00


Turbine Building Flood Analysis
Region 5 Case 85.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 8
Core Inlet Temperature (F)
Time (min)
RETRAN Selected HTC
Fixed HTC = 9000 Btu/hr-ft2-°F
0
100
200
300
400
500
600
0.00
500.00
1000.00
1500.00
2000.00
2500.00
3000.00
3500.00
4000.00
4500.00
5000.00


Turbine Building Flood Analysis
Region 5 Case 85.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 9
RCS Subcooling (F)
Time (min)
RETRAN Selected HTC
Fixed HTC = 9000 Btu/hr-ft2-°F


Turbine Building Flood Analysis
Region 5 Case 85.min
Fixed HTC vs. RETRAN Selected HTC
RAI-1.B Figure 10
SG Pressure (psig)
Time (min)
SG-A- RETRAN Selected HTCs
SG-B- RETRAN Selected HTCs
SG-A - Fixed HTC = 9000 Btu/hr-ft2-°F
SG-B - Fixed HTC = 9000 Btu/hr-ft2-°F

RAI-1.C

Item 31 of the conditions of use in the safety evaluation report (SER) for Electric Power Research Institute (EPRI) Topical Report NP-7450(P), Revision 4, "RETRAN-3D - A Program for Transient Thermal-hydraulic Analysis of Complex Fluid Flow Systems," states, "The pressurizer model requires model qualification work for the situations where the pressurizer either goes solid or completely empties," and Item 37 states, "For PWR (pressurized water reactor) transients where the pressurizer goes solid or completely drains, the pressurizer behavior will require comparison against real plant or appropriate experimental data." The staff requests the licensee to describe what plant/experimental data was used to qualify code response for thermal stratification. The staff also requests the licensee explain how the updated modelling (i.e., regular nodes below the pressurizer heaters) is applicable to the qualification work.

Duke Energy Response

The Staff position for RETRAN-3D SER limitations 31 and 37 are referenced to the Staff position for Item 18, which is excerpted below:

The staff notes that when a pressurizer fills or drains, a single region exists for which the normal pressure equation of state is used. Lack of numerical discontinuities in validation analyses of filling and draining pressurizers indicates that the model is functioning properly. It is the responsibility of the code user to justify any numerical discontinuity in the pressurizer during a filling or draining event.

With regard to SER Conditions related to filling and draining a pressurizer non-equilibrium volume, those TBF cases in which this occurs were reviewed and found to have no noticeable discontinuities in the system response at the particular times at which these conditions occurred.

Work documented in Volume 4 of the RETRAN-3D theory manual (see ADAMS Accession No. ML16315A295) benchmarks a RETRAN single node pressurizer and an eight node pressurizer to the NEPTUNUS Pressurizer tests performed at Delft University in the Netherlands. This benchmark was done to demonstrate thermal stratification effects in the pressurizer for insurge and outsurge transients with the presence of spray flow. Results of this benchmark demonstrate that the multi-node pressurizer response closely matched the test results, while the single node pressurizer response diverged significantly from the test results.

The current modeling is consistent with this benchmark work in the **[** **]**. Based on the documentation presented in Volume 4 of the RETRAN-3D theory manual for this benchmark, the NEPTUNUS pressurizer model did not include pressurizer heaters which allowed for modeling the entire pressurizer region with subnodes in the RETRAN benchmark. Due to the use of pressurizer heaters during the TBF event, it was decided to use **[** **]**.

RAI-1.D

The staff position for Item 18 of the RETRAN SER states, "While the model does not directly account for thermal stratification, its effects can be included by use of normal nodes below the pressurizer volume." The staff requests the licensee provide the basis for the choice of both the number of normal nodes used as well as the choice to only use them below the pressurizer heaters. Given that in the updated RETRAN model, the normal nodes make up only a small portion of the volume of the pressurizer, the staff requests the licensee to describe what was done to assure this was an acceptable modelling approach for both cases where the pressurizer completely empties as well as fills solid.

Duke Energy Response

Due to the **[ ]**, a volume size was chosen such that the possibility of those volumes becoming Courant limited during the transient was minimized. **[ ]** volumes were chosen as a reasonable number to represent this. The nodalization scheme used for benchmarking the NEPTUNUS pressurizer tests (see RAI-1-C response) in RETRAN-3D subdivided the test model pressurizer into eight equal size subnodes that were approximately 1.0 feet in height. The volume heights of the **[ ]** subnodes used to model the Oconee pressurizer **[ ]** are slightly less than this **[ ]**. This modeling is expected to provide similar, if not better, thermal stratification predictions in the lower pressurizer region as seen in the NEPTUNUS tests.

The decision to subnodalize **[ ]** is twofold:

1. In RETRAN, it is preferable to maintain the pressurizer level within the non-equilibrium portion of the pressurizer during the course of the event. This is desirable in that it helps address RETRAN-3D SER Conditions 18, 31, and 37. Given the broad range of pressurizer levels seen in the different cases performed for the TBF work, **[ ]**. There were still 2 cases that dropped below this elevation, but those cases were verified not to have any discontinuities during the times the non-equilibrium volume emptied or began to refill.

2. The second reason for picking the **[ ]** is that pressurizer heaters are used during the course of the event, and it is expected that pluming of water would occur when the heaters are energized. Thermal stratification above the heater elevation would therefore be unlikely during times that pressurizer heaters are active.

RAI-1.E

While 1-D codes such as RETRAN can simulate thermal stratification with appropriate noding, they generally have little to no heat transfer between adjacent nodes when there is little to no flow (as would be the case in the pressurizer during the majority of the three-day TBF event). The staff requests the licensee to provide RETRAN results showing the axial temperature distribution, and to explain how the lack of mixing between adjacent nodes in the lower pressurizer region is acceptable for both overcooling and overheating events.

Duke Energy Response

After steady-state conditions are achieved in the TBF cases where the SSF letdown line has been throttled to match RC makeup, the pressurizer reaches a near stagnant condition with almost no change in level seen for the remainder of the event. With only a small mass oscillation occurring into and out of the pressurizer due to cycling of the main steam relief valves (MSRVs) (for those cases that cycle on MSRVs), a stratified axial temperature distribution develops through the RETRAN pressurizer nodes. This axial temperature distribution through the pressurizer nodes is shown in RAI-1.E Figures 1 and 2 for both an overheating case (Case eoc.max) and an overcooling case (Case 85.max). These two cases are generally representative of the axial temperature distributions seen in all of the TBF cases (overheating and overcooling).

RETRAN does not model heat transfer between adjacent volumes of fluid (i.e., fluid-to-fluid). Energy exchange occurs through mass movement from one volume to another and via heat conductors attached to volumes (special purpose models such as non-conducting heat exchangers also provide the ability to transfer energy to/from volumes). When stagnated conditions occur in the pressurizer where little to no mass is exchanged between adjacent volumes, distinct temperature differentials can occur among the volumes. RAI-1.E Figures 1 and 2 demonstrate this. In both figures, the top most volume (non-equilibrium Volume 13, identified as the pzr liquid/pzr vapor trend lines) show that pressurizer heaters maintain a relatively constant saturated condition during the event since heaters are cycled to maintain a target RCS pressure condition. The pressurizer volumes below the heaters elevation **[ ]** show a lower temperature stratification since minimal movement of mass occurs between these volumes and the top most volume with the heaters. The heat conductors associated with **[ ]** are transferring energy from these volumes to the containment (ambient losses) which allows the volume temperatures to decrease below the top most volume with the heaters.

RAI-1.E Figure 1 shows that these lower volumes achieve a semi steady-state condition due to the fact that the MSRVs cycle for the duration of the event, resulting in a small shrink/swell effect on the primary system as RCS temperatures change slightly with the lift and reseat of the valves. This allows for some mass exchange between these volumes and energy movement from the top pressurizer volume into the lower pressurizer volumes. This is also true for RAI-1.E Figure 2 which shows a similar response for the first 200 minutes after which the MSRVs no longer cycle. Beyond this time, the pressurizer volumes **[ ]** show a continual decrease in temperatures since energy movement from the top pressurizer volume into these lower volumes has stopped and ambient losses continue to remove energy from these volumes.

It is expected that some mixing would actually occur within these lower volumes of the pressurizer if modeled in a 3-D manner, resulting in a more "averaged" temperature profile. The difference between the RETRAN response and that of a more realistic response is considered to be negligible in that the total ambient losses from the RETRAN volumes with their distinct axial temperature profile would be very close to the total ambient losses from a more homogenized equivalent.

RAI-1.F

As stated in the Enclosure to LAR 2017-03, the SSF auxiliary service water (ASW) pump suction supply is lake water from the embedded Unit 2 Condenser Circulating Water (CCW) supply piping and the limiting turbine building internal flooding event occurs as the result of failure of a CCW piping expansion joint. In addition, during the TBF, procedures would have operators trip the CCW pumps to stop/reduce the break flow. Given the failure in the CCW piping and tripped pumps, the staff requests the licensee to describe what is the resulting effect on the ASW flowrate to the steam generators and whether this effect (if any) was included in the RETRAN analysis.

Duke Energy Response

The postulated failure of the CCW piping expansion joint and the subsequent tripping of the CCW pumps has no effect on the SSF ASW flowrate provided to the steam generators. Hence it does not impact the RETRAN analysis. The inlet to the suction pipe that feeds the SSF ASW pump is located inside the underground portion of the Unit 2 CCW supply line. Since the underground CCW supply pipe is located at a lower elevation than the CCW pipe expansion joint, water contained in this pipe is available to feed the SSF ASW system if a failure of the CCW piping expansion joint occurs. Analysis shows that the water volume contained in the underground portion of the Unit 2 CCW supply pipe is adequate to feed the SSF ASW pump at the flow rates used in the RETRAN analysis until the SSF submersible pump is installed to refill the Unit 2 CCW supply pipe.

SSF ASW pump NPSH requirements and margin to avoid vortex formation at the inlet of the SSF ASW supply pipe were considered when the supporting analysis was performed. The following conservative inputs to the analysis were applied:

- Water located in the CCW pipe at an elevation above the pipe break is assumed to be unavailable.
- No credit is taken for CCW inventory from other units.
- Loads which normally take suction from the Unit 2 CCW pump are operating at their maximum flow rates until water level in the CCW pipe falls below the inlet of the pipe which supplies this equipment.
- The 2nd siphon continues to remove inventory until it fails.
- No credit is taken for CCW pump operation, siphon flow, or gravity induced reverse flow to refill the CCW pipe. CCW pump operation and siphon flow are expected to be lost when the pumps are tripped due to flooding.

RAI-2 (SRXB)

The following RAIs are related to the proposed acceptance criteria for off-nominal conditions and are needed in order for the staff to determine if water-solid operation is an acceptable configuration for maintaining safe shutdown during an SSF TBF event.

RAI-2.A

Page 5 of the Enclosure to LAR 2017-03 states, "operators maintain RCS pressure in a band of approximately 1950 to 2250 psig (pounds per square inch gauge]." Then, on Page 14, it states, "Results from the T-H (thermal-hydraulic) analyses show RCS pressure remains more than 700 psi below the Pressurizer Safety Valve (PSV) lift setting with a water-solid pressurizer condition for the duration of the event." Given the lowest allowable PSV setpoint is 2,425 psig (per Technical Specification 3.4.10), then 700 psig below the setpoint would be 1,725 psig, which is significantly below the ~1,950 to 2,250 psig stated previously. The staff requests the licensee to explain this discrepancy and clarify the margin to passing liquid through a PSV.

Duke Energy Response

The statement made on Page 5 of the Enclosure to the LAR "operators maintain RCS pressure in a band of approximately 1950 to 2250 psig" refers to how operators control RCS pressure from the SSF when pressurizer level is on scale and a steam bubble is present. The statement made on Page 14 of the LAR "Results from the T-H (thermal-hydraulic) analyses show RCS pressure remains more than 700 psi below the Pressurizer Safety Valve (PSV) lift setting with a water-solid pressurizer condition for the duration of the event" relates to how operators control RCS pressure from the SSF when pressurizer level is off scale high and possibly in a water solid condition. When RCS temperature is ≥350 °F, operators will control RCS pressure to a target setpoint of 1600 psig per the proposed operator guidance described in the RETRAN TBF thermal-hydraulic analysis. The TBF thermal-hydraulic analyses modeling this mode of control showed that RCS pressure remained more than 700 psi below the nominal PSV lift setpoint (2500 psig) for those off nominal cases (high decay heat/low initial temperature) in which indicated pressurizer level was off scale high and/or a water-solid condition was present in the pressurizer.

RAI-2.B

Page 14 of the Enclosure to LAR 2017-03 states, "Changes to the SSF letdown line control valve position is a manual action from the SSF, and the operator is required to maintain a very high awareness of the plant status for RCS pressure." In cases where the pressurizer level goes off-scale high and becomes water solid, the staff requests the licensee to describe whether the operators can increase the new SSF letdown line flow, or whether it is at its maximum in the analysis. The staff also requests the licensee to describe what other options the operators have to reduce pressure and to reduce the chance of water passing through the PSVs if the pressurizer is water solid. The staff requests the licensee to describe whether the pressurizer would still become water solid if the operators were to open the new letdown to its maximum.

Duke Energy Response

The new SSF letdown line is designed to pass approximately 300 gpm flow at nominal RCS conditions, but varies as a function of RCS pressure and the position of the throttle valves. The maximum flow predicted at any time in the RETRAN thermal-hydraulic analyses was ~250 gpm, thus there was some extra SSF letdown line capacity available.

The operating strategy for controlling the plant during the evolution into and during a water-solid condition is to maintain RCS subcooling such that RCS natural circulation flow is not interrupted in the primary loops. During the heatup and swell of the RCS in the off nominal cases that evolve to a water-solid condition, relatively cooler water is entering the pressurizer which subcools the liquid region. By controlling RCS pressure to a minimum condition of 1600 psig using the SSF letdown line, RCS subcooling is assured since the RCS will not reheat above ~550°F. This maximum temperature condition is controlled by the lowest lifting Main Steam Relief Valves. A minimum subcooling margin of >50°F is accomplished by controlling RCS pressure to 1600 psig. The recovery strategy is to allow available pressurizer heaters to re-saturate the pressurizer where a steam bubble is recovered such that the pressurizer level comes back on scale. At this time, operators can than switch the plant controlling strategy to use pressurizer heaters for RCS pressure control and SSF letdown line throttling to control to a targeted pressurizer level setpoint.

If operators were to open the SSF letdown line beyond what was analyzed, RCS pressure would decrease below the 1600 psig setpoint and could potentially cause a loss of subcooling outside of the pressurizer. This would be undesirable in that it could impact RCS natural circulation in the loops. The water solid operation strategy is designed to ensure RCS subcooling is maintained at all times outside of the pressurizer.

It is unlikely for all cases that went water-solid in the T-H analyses that further opening of the SSF letdown line would have prevented the pressurizer from reaching a water-solid condition. Until the liquid region of the pressurizer re-saturates and pressurizer heaters are able to add steam to the vapor volume, condensation on the pressurizer walls and interfacial heat transfer would continue decreasing the remaining steam bubble after operators begin SSF letdown line operation. Excessive opening of the SSF letdown line to recover pressurizer level could result in a loss of subcooling condition outside of the pressurizer.

Operators can use the Atmospheric Dump Valves (ADVs) to terminate the reheat and swell of the RCS prior to the RCS reheating to ~550°F if time is available for this action and the ADVs are available. This would stop the RCS swell from increasing pressurizer level, though as already discussed; the pressurizer would become subcooled to some degree prior to the ADVs being used. Condensation and interfacial heat transfer in the vapor region of the pressurizer would continue to decrease the steam bubble until the pressurizer re-saturates with use of the pressurizer heaters.

RAI-2.C

Regarding meeting the success criteria for the TBF event, page 6 of the Enclosure to LAR 2017-03 states, "This condition was reported as an unanalyzed condition that significantly degraded plant safety." Then, on page 7, it states that the four days with low decay heat and 10 hours in high decay heat/low RCS temperature "does not result in an appreciable contribution to overall plant risk." The staff requests the licensee to clarify this apparent inconsistency.

Duke Energy Response

The statement on page 6 is based on the reporting criteria of 50.73(a)(2)(ii)(B) since associated thermal and hydraulic analyses did not consider ONS operating conditions during shutdown and startup and subsequent evaluation and analysis efforts did not support SSF operability for all credited events. As noted in the LER, Duke Energy used a risk-informed approach to determine the risk significance associated with the unanalyzed conditions existing for the SSF mitigated event. The Conditional Core Damage Probability (CCDP) associated with this event was determined to be less than 1.0E-06 due to the average exposure period and was therefore considered to have a small risk impact. Subsequent PRA evaluation, determined the CCDP to be at least a factor of 10 lower than that provided in the LER and the conclusion that the small duration of time during these off-nominal conditions does not result in an appreciable contribution to overall risk.

RAI-3 (PRA Operations and Human Factors Branch (APHB))

The following RAIs pertain to Section 2.3.3 of the LAR 2017-03 Enclosure, which states, in part:

> Although the RCS may become water-solid, the modifications to the SSF RC (reactor coolant) Makeup System described in Section 2.1.2.2 will eliminate the potential for water relief through the pressurizer safety valves by providing the ability to significantly increase SSF reactor coolant letdown flow.

RAI-3.A

The staff requests the licensee to describe what the operator action time margin is associated with the time required for the operator to take control of the SSF throttle valve and manipulating it to prevent water relief through the pressurizer safety valves.

Duke Energy Response

The procedural guidance modeled in the Region 4 off-nominal operation conditions thermal-hydraulic analyses for water-solid operation that has operators opening the SSF letdown line to control RCS pressure at 1600 psig when the RCS temperature is ≥350°F and LTOP protection is not required. The 1600 psig setpoint chosen for this provides 900 psi margin to the nominal lift setpoint of the pressurizer safety relief valves (2500 psig). Sensitivity studies were performed to determine the operator action time margin associated with this action. These sensitivity cases assumed that the operators did not open the SSF letdown line when RCS pressure reached 1600 psig to determine when water relief through the pressurizer PORV would begin. The sensitivity cases modeled the PORV which has a setpoint of 2450 psig, which is 50 psi lower than the PSV setpoint of 2500 psig. These times are therefore slightly conservative relative to water-relief through the PSV. The table below summarizes the results of these sensitivities:

1 Case	2 Time at Which Operator is Dispatched to SSF (sec) see Note 6	3 Time of SSF Letdown Availability (sec) see Note 1	4 Time At 1600 psig (sec)	5 Time of PORV Water Relief at 2450 psig (sec)	6 Water Relief Margin (min)	7 Additional Time for Opening SSF Letdown line (min) see Note 5
500f.margin.out	3992	5828	see Note 2	7438	26.8 (Note 3)	0
450f.margin.out	5892	7728	7124	9407	28.0 (Note 3)	0
400f.margin.out	7652	9488	9286	11382	31.6 (Note 3)	0
350f.margin.out	9502	11338	11588	13466	31.3 (Note 4)	4.2
300f.margin.out	11392	13228	14454	15244	13.2 (Note 4)	20.4
250f.margin.out	14192	16028	19946	20378	7.2 (Note 4)	65.3

Note 1 – This time reflects operators initiating SSF letdown within 20 minutes of losing normal letdown due to loss of Low Pressure Service Water (LPSW)

Note 2 – The TBF event for case 500f.margin.out initiates at a RCS pressure greater than 1600 psig

Note 3 – This margin is defined as Column 5 minus Column 3

Note 4 – This margin is defined as Column 5 minus Column 4

Note 5 – This time is defined as Column 4 minus Column 3

Note 6 – Time after reactor shutdown (this encompasses the unit cooldown time for each case)

The second column identifies the time at which an operator is first dispatched to the SSF from the main control room as required by procedures. The third column identifies the time in the event at which operators are credited to manipulate the SSF letdown line throttle valves to control RCS pressure to 1600 psig when RCS temperature is ≥350°F and LTOP protection is not required. The fourth column identifies the time in the event that RCS pressure reaches the target setpoint at which operators would open the SSF letdown line and begin controlling RCS pressure to 1600 psig. The fifth column identifies the event time at which water relief through the PORV begins, assuming no operator action was taken to open the SSF letdown line. The sixth column identifies the operator action time margin.

The seventh column identifies the amount of time operators have between the time they are capable of opening the SSF letdown line and the time at which RCS pressure increases to the 1600 psig setpoint for each case (Column 4 minus Column 3). In the two limiting cases (300f.margin.out and 250f.margin.out), letdown line availability occurs well before the time RCS pressure increases to 1600 psig where operators would open the letdown line. For case 300f.margin.out this time is ~20 minutes (14454 sec – 13228 sec) and for case 250f.margin.out this time is ~65 minutes (19946 sec – 16028 sec). During this time, operators would be actively monitoring RCS conditions such as RCS pressure, temperatures, pressurizer level, and SG pressures. This represents additional time that operators have to evaluate the progression of the event and prepare for opening the SSF letdown line at the desired condition of 1600 psig.

RAI-3.B

The staff requests the licensee to provide the basis and justification regarding the feasibility and validation for the operator to manually throttle the SSF letdown line valve to prevent water relief through the pressurizer safety valves.

Duke Energy Response

The current SSF letdown line is sized to pass a flow rate ≥ the flow rate added to the Reactor Coolant System (RCS) by SSF RC makeup pump for an SSF event that occurs from a nominal operating condition. The letdown line contains two in-series motor operated isolation valves, an upstream control valve and a downstream block valve. These valves are located inside containment, are powered from the SSF and can only be operated from the SSF control room. The SSF letdown control valve was designed as, and originally functioned as, a throttle valve, but due to subsequently identified design limitations the valve is now only cycled completely open and closed.

The Standby Shutdown Facility Emergency Operating Procedure (SSF EOP) provides guidance for operating the letdown valves following an SSF event that occurs from a nominal operating condition. With PZR level on-scale, the control valve is cycled to maintain pressurizer (PZR) level within a 20-inch control band, e.g., when PZR level approaches the top of the control band the control valve is fully opened and the valve is fully closed when PZR level approaches the bottom of the control band. As a contingency, the SSF EOP also provides guidance for maintaining the unit in a safe shutdown condition with a water solid PZR. With the RCS water solid, the control valve is operated as previously described but the controlling parameter is RCS pressure with a control band of 1600 - 2200 psig. Maintaining the plant in a water solid safe shutdown condition has been validated on the Operations Training SSF simulator.

The new SSF letdown line will contain a solenoid operated isolation valve and two in-parallel motor operated throttle valves. These valves will be located inside containment, will be powered from the SSF and can only be operated from the SSF control room. The new valve control switches will be located on the control board in approximately the same location as the current valve switches.

For an SSF event that occurs from a nominal operating condition, a steam bubble will be maintained in the PZR and the new SSF letdown valve will be throttled as necessary to match RC letdown with SSF RCMU pump flow and maintain PZR level constant. This is similar to the existing procedural guidance except the cycling of PZR level will no longer be required.

For an SSF event that occurs from an off-nominal operating condition, the new SSF letdown valve will be throttled open once RCS pressure exceeds 1600 psig. The throttling of SSF letdown will consist of adjusting SSF letdown flow as necessary to both accommodate the expansion of the RCS inventory as RCS temperature increases, as well as, maintaining RCS pressure constant as the steam bubble collapses in the PZR. Once the PZR is water solid with RCS temperature constant, SSF letdown will continue to be throttled as required to maintain a RCS pressure of approximately 1600 psig. Maintaining an RCS pressure of approximately 1600 psig provides a 900 psig margin to the nominal 2500 psig lift setpoint of the PZR code safety relief valves. This is similar to the existing procedural guidance except the cycling of PZR level will no longer be required.

Revised SSF letdown procedural guidance will be developed prior to Operation's taking operational control of the new letdown line, and, based on its improved throttling capability, the new letdown line will eliminate the operator burden associated with the existing letdown line arrangement.

RAI-3.C

The staff requests the licensee to provide a description of the potential impacts on the reactor/plant should the operator fail to manually throttle the SSF letdown line valve to prevent water relief through the pressurizer safety valves.

Duke Energy Response

The SSF letdown line throttle valves are sized with ample margin to offset an increase in RCS water volume that could occur due to reheating of the RCS and due to SSF RC makeup pump operation during a Turbine Building Flood. The valve trim and stroke time for these throttle valves were chosen to provide the controllability needed to support event mitigation.

SSF events that initiate from a low RCS temperature with high decay heat condition result in an insurge into the Pressurizer and an increase in RCS pressure. The SSF EOP will be revised to direct the operator to establish SSF letdown flow to control the increase in RCS pressure during these scenarios and the PORV block valve will not be closed until RCS pressure has been stabilized below the PORV lift setpoint.

If the SSF Control Room Operator fails to open the SSF letdown line throttle valve enough to prevent RCS pressure from approaching the pressurizer safety valve setpoint, the PORV will lift and control RCS pressure below the Pressurizer Code Safety valve setpoint. Once the operator has stabilized RCS pressure below the PORV lift setpoint the PORV block valve will be closed from the SSF Control Room to isolate this potential RCS inventory diversion flowpath.

RAI-4 (APHB)

The following RAIs pertain to Section 3.1 of the LAR Enclosure, which states, in part:

> Although the RCS (reactor coolant system) may become water-solid, the modifications to the SSF RC (reactor coolant) Makeup System described in Section 2.1.2.2 will eliminate the potential for water relief through the pressurizer safety valves by providing the ability to significantly increase SSF reactor coolant letdown flow.
>
> Changes to the SSF letdown line control valve position are a manual action from the SSF, and the operator is required to maintain a very high awareness of the plant status for RCS pressure.

RAI-4.A

The staff requests the licensee to describe the procedures being implemented to direct operator manual throttling of the SSF letdown line valve to prevent water relief through the pressurizer safety valves.

Duke Energy Response

The current SSF letdown control valve was originally designed as a throttle valve, but due to subsequently identified design limitations the valve is now only cycled completely open and closed. Procedurally, the letdown control valve is cycled to maintain PZR level within a 20-inch control band, e.g., when PZR level approaches the top of the control band the control valve is fully opened and the valve is fully closed when PZR level approaches the bottom of the control band.

Following installation of the new high flow capacity SSF letdown line, the procedural guidance for throttling SSF letdown will be revised for an SSF event that occurs from both nominal operating conditions and from off-nominal operating conditions.

For an SSF event that occurs from a nominal operating condition, a steam bubble will be maintained in the PZR and procedural guidance will be provided to throttle open the new SSF letdown control valve as required to match SSF RCMU pump flow and maintain PZR level constant. A target control band may be provided but the expectation will be to maintain a constant PZR level within this control band and the cycling of PZR level will no longer be required.

For an SSF event that occurs from a high decay heat/low RCS temperature off-nominal operating condition, the RCS will begin to reheat and re-pressurize. Procedural guidance will be provided to throttle open the new SSF letdown control valve when RCS pressure exceeds 1600 psig and SSF letdown will continue to be throttled as required to maintain an RCS pressure of approximately 1600 psig as the RCS continues to reheat back to 550°F. The throttling of SSF letdown will consist of adjusting SSF letdown flow as necessary to accommodate the expansion of the RCS inventory as RCS temperature increases, as well as, maintaining RCS pressure constant as the steam bubble collapses in the PZR. Once RCS temperature stabilizes at 550°F and the PZR is water solid, SSF letdown will be throttled as required to maintain an RCS pressure of approximately 1600 psig. A target control band may be provided but the expectation will be to maintain a constant RCS pressure within this control band.

The revised SSF letdown procedural guidance will be developed, validated, and issued prior to Operations taking operational control of the new SSF letdown line.

RAI-4.B

The staff requests the licensee to describe the training that is being provided initially and periodically regarding operator manual throttling of the SSF letdown line valve to prevent water relief through the pressurizer safety valves.

Duke Energy Response

Licensed operator candidates receive classroom training on the current SSF letdown line configuration during participation in the Initial License Training (ILT) program. Licensed operator candidates receive simulator training on stabilizing the plant from the SSF during a nominal case SSF scenario. This training is conducted on the SSF simulator. Licensed operator candidates receive simulator training on maintaining PZR level within a prescribed band when the PZR is saturated using SSF letdown, as well as, throttling SSF letdown to maintain RCS pressure within a prescribed band when the RCS is water solid. This training is conducted using the SSF simulator. Licensed operator candidates also complete a task qualification on placing the plant in a safe shutdown condition from the SSF. The task qualification is performed by walking through the SSF procedure steps in the SSF control room.

Licensed operators receive periodic classroom training on the current SSF letdown line configuration during participation in the Licensed Operator Requalification (LOR) program. Licensed operators receive periodic simulator training on stabilizing the plant from the SSF during a nominal case SSF scenario. This training is conducted using the SSF simulator.

Licensed operators will receive classroom and simulator training on throttling SSF using the new SSF letdown line configuration to mitigate nominal and off-nominal turbine building flood scenarios prior to the new SSF letdown configuration being placed in service. The simulator training will be conducted on the SSF simulator. This training will include both the throttling of SSF letdown to maintain PZR level within a prescribed band when the PZR is saturated, as well as, throttling SSF letdown to maintain RC pressure within a prescribed band when the RCS is water solid.

Classroom and simulator training on throttling SSF using the new SSF letdown line configuration to mitigate nominal and off-nominal turbine building floods will also be incorporated into the ILT and LOR programs.

RAI-4.C

The staff requests the licensee to describe the specific controls that facilitate the operator maintaining the necessary high alertness of plant status while controlling SSF letdown via the new throttle valve.

Duke Energy Response

The SSF RCMU pump is a positive displacement pump that remains in continuous operation during an SSF event. The SSF letdown line is not provided with a flow instrument. Therefore, control of letdown from the SSF is primarily a response to RCS temperature, RCS pressure and PZR level. The operator will maintain a high level of plant awareness when controlling and monitoring these parameters while maintaining the unit in a safe shutdown condition from the SSF control room.

During an SSF event from nominal plant conditions a steam bubble will be maintained in the PZR and PZR level will remain on-scale. RCS cold leg temperatures will stabilize and remain constant at approximately 550°F. The operator will slowly raise SG levels to the natural circulation setpoint. With RCS temperature stable at approximately 550°F and PZR level > 90", the operator will slowly throttle open the SSF letdown line valve to match RC letdown with makeup by establishing a letdown flow rate that maintains PZR level constant. Changes in RCS temperature can affect PZR level and RC pressure. The operator will continuously monitor RCS temperature, RCS pressure and PZR level, making any needed minor adjustments to the SSF ASW flowrate in order to maintain a proper primary to secondary system heat balance while raising SG levels.

For an SSF event that occurs from a high decay heat/low RCS temperature off-nominal operating condition, a steam bubble will initially be present in the PZR and PZR level will initially be on-scale. The RCS will begin to reheat and re-pressurize, and the RCS inventory will begin to expand which increase RCS pressure and PZR level. The operator will monitor RCS temperature, RCS pressure and PZR level. Once RC pressure exceeds 1600 psig the operator will establish letdown from the SSF and continue to throttle letdown as required to maintain an RCS pressure of approximately 1600 psig as the RCS continues to reheat back to 550°F. The throttling of SSF letdown will consist of adjusting SSF letdown flow as necessary to both accommodate the expansion of the RCS inventory as RCS temperature increases, as well as, maintaining RCS pressure constant as the steam bubble collapses in the PZR. Based on training, the operator will recognize that RC pressure will increase at a greater rate once the RCS becomes water solid and will increase SSF letdown flow accordingly. A 900 psig margin is provided between the target RC pressure of 1600 psig and the 2500 psig nominal lift setpoint of the PZR code safety relief valve. Once RCS temperature stabilizes at 550°F and the PZR is water solid, SSF letdown will be throttled as required to maintain an RCS pressure of approximately 1600 psig.

RAI-4.D

The staff requests the licensee to describe any operating experience from Oconee or other plants associated with RCS pressure/temperature control with a water-solid pressurizer condition.

Duke Energy Response

A search of the INPO Encyclopedia of Operating Experience database identified three plant events that resulted in water solid conditions.

On April 7, 1994, power at Salem Unit 1 was reduced rapidly because marsh grass was clogging the circulating water intake screens, resulting in automatic trips of circulating water pumps. Reactor power reduction was not balanced with the turbine load reduction and changes in reactor coolant temperature were not well controlled. Reactor coolant pressure and pressurizer level began decreasing rapidly. Subsequent to the reactor scram, the reactor coolant system temperature increased after the main steam isolation valves were closed. The reactor coolant temperature was not stabilized, and the main steam atmospheric dump valves failed to operate as designed to limit the temperature increase. The reactor coolant temperature increase, combined with a partial safety injection (SI), raised pressure and increased pressurizer level to water-solid conditions. This resulted in repeated, rapid opening and closing of the pressurizer power-operated relief valves. The pressurizer power-operated relief valves opened and closed repeatedly for approximately 20 minutes until reactor coolant pressure was decreased by steam generator cooling and by balancing letdown and makeup. Pressurizer heaters were used to raise the pressurizer water temperature to saturation and pressurizer level returned on scale. Approximately four hours after the scram a plant cooldown was initiated using plant procedures.

On February 6, 1996, Catawba Unit 2 automatically scrammed from 100 percent power following a loss of off-site power (LOOP) when protective relaying caused the lockout of both main power transformers. During post-trip plant stabilization, operators observed that steam line pressure was decreasing and closed all main steam isolation valves (MSIV) as steam generator pressure approached 800 psig. Shortly after closing the MSIVs, the plant experienced a steam line low pressure SI actuation. As a result of SI flow, reactor coolant (RCS) pressure increased, and one power-operated relief valve (PORV) cycled to control RCS pressure.

Primary decay heat removal was provided by a combination of natural circulation cooling by steaming three steam generators and by automatic cycling of a PORV. Approximately seven hours after the loss of power, a pressurizer bubble was established to control RCS pressure. After the pressurizer bubble was formed, a natural circulation cooldown was established to achieve cold shutdown.

On September 17, 2011, McGuire Unit 1 was performing a cooldown for a refueling outage. While waiting for LTOP to be established, Operations was increasing pressurizer level per procedure to greater than or equal to 85 percent pressurizer level. This procedure also required establishment of maximum letdown per the RCS letdown procedure. At approximately 87% pressurizer level, RCS pressure started to increase. The increase in pressure occurred due to a mismatch in charging and letdown flow. Indicated pressurizer level was 87 percent. This corresponds to an actual pressurizer level of greater than 95 percent. Operators decreased charging flow and increased letdown flow to stop the pressure increase (e.g., inventory balance). RCS pressure was returned to the original value but the operators had to continue to reduce charging flow to maintain balance with a decreasing letdown flow. As operators continued to reduce charging flow, charging flow went to <20 gpm for greater than 20 seconds, which satisfied an interlock and a letdown isolation occurred. This resulted in RCS pressure slowly increasing due to seal injection flow with letdown isolated. The event was not consequential because the operators took procedural actions to mitigate the event.

Several Westinghouse plants place the unit in a water solid operating condition either during a normal plant startup or shutdown in order to ensure that non-condensable gases are removed from the RCS. This evolution is performed at low RCS pressure and temperature conditions and RCS pressure control is provided entirely by balancing RCS makeup and letdown.

Oconee has not experienced an event that resulted in water solid conditions. Oconee has procedural guidance to maintain the unit in a water solid safe shutdown condition from both the main control room and the SSF.

The guidance to maintain the unit in a water solid, safe shutdown condition from the main control room is provided in the Emergency Operating Procedure (EOP). In general, the EOP will direct the operators to maintain RCS temperature constant using the turbine bypass valves or ADVs and maintain RCS pressure below the PZR PORV lift setpoint of 2450 psig by adjusting RC makeup and letdown. The PZR heaters are energized and once the PZR has saturated, RCS makeup, letdown, and PZR heaters are used to establish a steam bubble in the PZR.

The guidance to maintain the unit in a water solid, safe shutdown condition from the SSF following a nominal SSF event is provided in the Standby Shutdown Facility Emergency Operating Procedure (SSF EOP). In general, RCS temperature is maintained constant at approximately 550°F (corresponds to the saturation temperature for the MSRVs with the lowest lift setpoint). The SSF EOP directs the operator to cycle the SSF letdown control valve open and closed to maintain RCS pressure between the band of 1600-2200 psig (the PZR PORV is isolated at the SSF to eliminate a potential RCS inventory diversion flow path). The PZR heaters are energized and once the PZR has saturated, SSF letdown and PZR heaters are used to establish a steam bubble in the PZR (the SSF RCMU pump is a positive displacement pump and remains in continuous operation).

RAI-4.E

The staff requests the licensee to describe the impact on plant operational/design margins associated with RCS pressure/temperature control with a water-solid pressurizer condition.

Duke Energy Response

Maintaining the plant in a safe shutdown condition with a water solid pressurizer using the new SSF letdown line configuration will improve operational margin as the new letdown line has a greater flow capacity and more precise throttling capability than the existing configuration.

Following an SSF event from a nominal operating condition, a steam bubble remains in the PZR and the PZR remains on-scale. The current SSF letdown control valve was designed as, and originally functioned as, a throttle valve, but due to subsequently identified design limitations the valve is now only cycled completely open and closed. Procedurally, the letdown control valve is cycled to maintain PZR level within a 20 inch control band, e.g., when PZR level approaches the top of the control band the control valve is fully opened and the valve is fully closed when PZR level approaches the bottom of the control band. This constraint requires that the letdown flow control valve be cycled approximately three times an hour which requires constant vigilance and increases the possibility of human error or equipment malfunction. With the new SSF letdown line configuration, RCS letdown flow can be adjusted to match makeup flow with only minor subsequent adjustments needed and operational margin will be improved.

As a contingency action, the current SSF event mitigation procedure also contains guidance for maintaining the plant in a safe shutdown condition with a water solid PZR. Procedurally, the current SSF letdown control valve is cycled to maintain RCS pressure within a 1600-2200 psig control band. Procedure validation on the SSF simulator has demonstrated that this is an acceptable method of control with a water solid PZR.

For an SSF event that occurs from a high decay heat/low RCS temperature off-nominal operating condition, the RCS will begin to reheat and re-pressurize. RCS inventory will begin to expand which increase RCS pressure and PZR level. RCS cold leg temperature will continue to increase until it stabilizes at 550°F. Mitigating the consequences of a turbine building flood from a high decay heat/low RCS temperature off-nominal plant condition using the current SSF letdown line configuration will not be successful as the current letdown line does not have the flow capacity required to divert the additional RCS inventory to the SFP in time to prevent the PZR from going water solid and relieving liquid out the PZR PORV.

With the new SSF letdown line configuration, operating margin during water solid PZR operation following an SSF event from a high decay heat/low RCS temperature off-nominal condition will be significantly improved as the new letdown line has adequate capacity to letdown the additional RCS inventory to the SFP and the new flow control valve provides for the precise matching of RCS letdown flow to makeup flow with a water solid PZR. The operator will maintain RCS pressure at approximately 1600 psig which will provide both an adequate RCS subcooling margin as well as providing an adequate margin to the nominal PZR safety valve lift setpoint of 2500 psig.

The throttling of the new SSF letdown line from an off-nominal plant condition may have a minor impact to operational margin in that the operator will be controlling letdown from a new plant condition that was not considered before, e.g., an off-nominal plant condition where the RCS continually heats up to 550°F. This potential impact on operational margin is considered to be minimal as new procedure guidance will be provided and the operators will receive classroom and SSF simulator training on controlling SSF from an off-nominal plant condition.

RAI-5 (APHB)

The following RAIs pertain to Section 2.4 of the Enclosure of LAR 2017-03, which identifies manual control of the MS ADVs as a new manual operator action requiring NRC review and approval.

RAI-5.A

The staff requests the licensee to describe the impact on plant operational/design margins associated with operator manual control of the ADVs to achieve plant cooldown as compared to the automatic functioning of the main steam relief valves.

Duke Energy Response

The SSF is designed to maintain the affected unit(s) in a natural circulation safe shutdown condition and the reactor coolant pumps are secured prior to placing the SSF systems in operation. The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs may be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occur from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occur from a high decay heat/low RCS temperature off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

One 12" atmospheric dump line is provided for each main steam line. This dump line contains a 1.5" hand operated atmospheric dump bypass control valve, a 10" hand operated atmospheric dump control valve and a 12" hand operated atmospheric vent valve. These three flow paths are installed in parallel and are provided with a common upstream hand operated isolation valve.

Reducing main steam pressure to below the lift setpoint of the main steam relief valves with the ADVs following a SSF mitigated event that occurs at nominal plant conditions will not adversely impact operational/design margin as this action will rely on the 1.5" atmospheric dump bypass control valve designed specifically for this purpose. Once NRC approval is received for operating the ADVs from the SSF new procedural guidance will be developed to use this flowpath for reseating the main steam relief valves.

Main steam pressure will be reduced to reseat the main steam relief valves by slowly throttling open the 1.5" atmospheric dump bypass control valve to lower MS pressure to a value where the MSRVs remain seated. The MSRV with the lowest lift setpoint is set for a nominal 1050 psig with a nominal reseat setpoint of 945 psig. There will be no impact to the plant as the design and size of the 1.5" bypass control valve limits the decrease in MS pressure to a value where the MSRVs remain seated, the flow rate through the valve is limited, the valve will be operated slowly, and the non-licensed operator will be under the constant direction of a licensed operator using an approved procedure. In the unlikely event that additional steam flow is required, the 10" control valve will be slowly throttled open until the MSRVs reseat. The 10" control valve is designed for precise throttling of steam flow in the event the turbine bypass to the condenser is unavailable for cooldown.

Stabilizing RCS temperature with the ADVs following a SSF mitigated event that occurs from a high decay heat/low RCS temperature off-nominal plant operating condition will not impact operational/design margin as this action relies on an existing ADV control system configuration and an existing operator action using an existing approved procedure.

Following a SSF mitigated event that occurs from a high decay heat/low RCS temperature off-nominal operating condition, a steam bubble will initially be present in the PZR and PZR level will be on-scale. The RCS will begin to reheat and the RCS inventory will begin to expand into the pressurizer which increases RCS pressure and PZR level. Without operator action RCS temperature will return to 550°F and the new SSF letdown line is designed to accommodate the resultant expansion of RCS inventory. However, it is desirable to use the ADVs to stabilize RCS temperature to minimize the volume of RCS inventory that must be letdown to the SFP. Utilizing the ADVs will have no impact on operational/design margin as the existing 10" ADV control valve is designed for precise throttling of steam flow. Guidance for using the ADVs as an alternate means of stabilizing RCS temperature or conducting a unit cooldown from the main control room is currently provided in the emergency operating procedure for events such as loss of condenser vacuum, station blackout, and LOCA cooldown with degraded HPI. The licensed and non-licensed operators receive initial and periodic continuing training on operation of the ADVs. Cooldown using ADVs was successfully demonstrated on Oconee Unit 1 on February 15, 2007 (Reference LER 269/2007-01, Revision 1, dated July 2, 2007). For an SSF mitigated event that occurs at a very low initial RCS temperature, the 12" vent valve may need to be opened to achieve the desired steaming rate.

After RCS temperature has been stabilized additional ADV operation is not anticipated as SSF letdown will be throttled to control RCS pressure. However, the steam bubble in the PZR may eventually collapse and the RCS may become water solid. If the RCS becomes water solid, SSF letdown will continue to be throttled to maintain RCS pressure constant. Over time, as decay heat dissipates, RCS temperature may begin to slowly decrease and it may be desirable to throttle the ADVs to again stabilize RCS temperature. The throttling of ADVs with a water solid RCS will have no impact on operational margin. This action utilizes the existing ADV control system configuration and an existing operator action using an existing approved procedure. The operators are trained to operate the ADVs in small increments and to verify that desired results are achieved before continuing. RCS temperature and pressure will be monitored by licensed personnel in the SSF control room, in the main control room if available, and in the Technical Support Center (TSC) if operational. Also, the new SSF letdown line can be used to adjust RCS pressure if required.

RAI-5.B

The staff requests the licensee to describe any operating experience from Oconee or other plants associated with achieving plant cooldown via manual control of the ADVs as compared to the automatic functioning of the main steam relief valves.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs will be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occurs from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occur from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

Oconee has experienced one event where ADVs were used to conduct a unit cooldown as documented in LER 269/2007-01, Revision 1, dated July 2, 2007).

On February 15th, 2007, Oconee Unit 1 tripped due to a disturbance on the grid. The Unit 1 trip was complicated because the unit's 4KV electrical busses did not rapid bus transfer from the auxiliary transformer (power supplied from main generator) to the startup transformer (power supplied from switchyard). By design, the failure of the electrical busses to rapid transfer resulted in a temporary loss of all secondary side non-safety related pumps, including the hotwell pumps, the condensate booster pumps, the main feedwater pumps, and the condenser circulating water pumps. With secondary plant equipment de-energized, the emergency feedwater system actuated and maintained level in the steam generators. During the transient, the Unit 1 reactor coolant pumps remained in operation. Initially the main steam relief valves (MSRVs) opened to relieve the excessive steam flow. The MSRVs reseated once the turbine bypass valves (TBVs) opened and controlled main steam pressure below the MSRV setpoint. Anticipating an eventual loss of condenser vacuum and the TBVs due to increasing hotwell level, a decision was made to use the atmospheric dump valves (ADVs) to cool down Unit 1 to low pressure injection decay heat removal entry conditions. Oconee does not have remote operated manual ADVs, only locally operated manual ADVs. The transition from TBVs to ADVs occurred approximately 7 hours after the trip. Unit cool down proceeded smoothly and unit temperature and pressure were reduced sufficiently to place the unit in Mode 4.

It is Oconee's understanding that no other plants in the industry use locally operated manual ADVs.

RAI-5.C

The staff requests the licensee to provide a description and disposition of the potential impacts on the reactor/plant resulting from miss-operation of the ADVs.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs will be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occur from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occur from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

One 12" atmospheric dump line is provided for each main steam line. This dump line contains a 1.5" hand operated atmospheric dump bypass control valve, a 10" hand operated atmospheric dump control valve and a 12" hand operated atmospheric vent valve. These three flow paths are installed in parallel and are provided with a common upstream hand operated isolation valve.

Misoperation of the ADVs while reducing main steam pressure to below the lift setpoint of the main steam relief valves following a SSF mitigated event that occurs at nominal plant conditions will have no impact on plant operations as this action relies on an existing 1.5" hand operated atmospheric dump bypass control valve described above that was specifically installed for this purpose. Main steam (MS) pressure will be reduced to reseat the main steam relief valves by slowly throttling open the 1.5" atmospheric dump bypass control valve to lower MS pressure to a value where the MSRVs remain seated. There will be no impact to the plant as the 1.5" bypass control valve has been designed to limit the decrease in MS pressure to a value where the MSRVs remain seated and limit the rate of steam flow through the valve such that rapid de-pressurization of the main steam header cannot occur. In the unlikely event that additional steam flow is required, the 10" control valve will be slowly throttled open until the MSRVs reseat. The 10" control valve is designed for precise throttling of steam flow in the event the turbine bypass to the condenser is unavailable for cooldown. Due to the reduced RCS flowrate present during natural circulation, RCS temperature will respond slowly to changes in ADV valve position. If the non-licensed operator throttles open the 10" ADVs more than required to reseat the MSRVs the licensed operator in the SSF control room will quickly recognize the condition and immediately correct the misoperation.

Stabilizing RCS temperature with the ADVs following a SSF mitigated event that occurs from a high decay heat/low RCS temperature off-nominal plant operating condition will have no impact on plant operation.

Following an SSF mitigated event that occurs from a high decay heat/low RCS temperature off-nominal operating condition, a steam bubble will initially be present in the PZR and PZR level will be on-scale. The RCS will begin to reheat and re-pressurize, the RCS inventory will begin to expand, and it is desirable to use the 10" ADV control valves to stabilize RCS temperature to minimize the volume of RCS inventory that must be letdown to the SFP. If the operator fails to open the ADVs or does not throttle the ADVs open sufficiently to stabilize RCS temperature, RCS temperature will eventually return to 550°F and be controlled by the MSRVs. The operator will throttle open the SSF letdown control valve to accommodate the resultant expansion of RCS inventory.

The SSF is designed to maintain the affected unit(s) in a natural circulation safe shutdown condition and the reactor coolant pumps are secured prior to placing the SSF systems in operation. Due to the reduced RCS flowrate present during natural circulation, RCS temperature will respond slowly to changes in ADV valve position. If the operator throttles open the ADVs more than required to stabilize RCS temperature the operator will quickly recognize the condition via local SG pressure and immediately correct the misoperation. Even if the valve misoperation is not corrected, the core will remain covered and cooled as contraction of the RCS will not result in an uncovered core.

It is highly unlikely that misoperation of the ADVs would occur or that there would be an impact to plant operations for the following reasons:

- The 1.5" bypass control valve is sized to limit the rate of steam flow through the valve.
- The 10" control valve is designed for precise throttling of steam flow in the event the turbine bypass to the condenser is unavailable for cooldown.
- The 'A' and 'B' steam line ADVs are located approximately 15' apart in an open area on the 5th floor (turbine deck) of the turbine building and the valves are well labelled. This physical separation minimizes the possibility of the operator operating the wrong ADV.
- Guidance for using the ADVs as an alternate means of stabilizing RCS temperature or for conducting a unit cooldown from the main control room is currently provided in the emergency operating procedure for events such as loss of condenser vacuum, station blackout, and LOCA cooldown with degraded HPI.
- Licensed and non-licensed operators receive initial and periodic continuing training on operation of the ADVs. Operation of the ADVs is a required non-licensed operator qualification task.
- The licensed operators are trained to initially operate the ADVs in small increments and wait for expected feedback before continuing.
- The non-licensed operator operates the ADVs under the constant direction of a licensed operator using an approved procedure.
- RCS temperature, pressure, and pressurizer level will be continuously monitored by licensed personnel in the SSF control room, in the main control room if available, and in the Technical Support Center (TSC) once it becomes operational.
- The ADVs are stroke tested by non-licensed operators under the direction of licensed personnel at full main steam system pressure during each unit's refueling outage.
- A unit cooldown using ADVs was successfully performed on Unit 1 on February 15, 2007 (Reference LER 269/2007-01, Revision 1, dated July 2, 2007).
- In the event that an ADV was misoperated during an off-nominal SSF event, the new SSF letdown line would be throttled open to compensate for any increase in RCS pressure and would be throttled closed to compensate for any decrease in RCS pressure.

RAI-5.D

The staff requests the licensee to describe the procedures being implemented to direct operator manual operation of the ADVs for plant cooldown.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs may be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occurs from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occurs from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

One 12" atmospheric dump line is provided for each main steam line. This dump line contains a 1.5" hand operated atmospheric dump bypass control valve, a 10" hand operated atmospheric dump control valve and a 12" hand operated atmospheric vent valve. These three flow paths are installed in parallel and are provided with a common upstream hand operated isolation valve. Each atmospheric dump line is also provided with a normally isolated local main steam pressure gauge.

The Standby Shutdown Facility Emergency Operating Procedure (SSF EOP) provides guidance to place the affected unit in a safe shutdown condition following an event that requires the SSF for event mitigation.

Following a SSF mitigated event that occurs during nominal plant conditions it is desirable to minimize the unnecessary cycling of the MSRVs and procedural guidance will be added to SSF EOP to direct a non-licensed operator to valve in the local ADV main steam pressure gauge, establish communications with the SSF control room and, when directed by the SSF control room, slowly throttle open the 1.5" bypass control valve until the main steam relief valves have reseated. The 1.5" bypass control valve is sized to limit the decrease in MS pressure to a value where the MSRVs remain seated and the flow rate through the valve is limited by the size of the piping. In the unlikely event that additional steam flow is required, the 10" control valve will be slowly throttled open until the MSRVs reseat.

Use of the ADVs as an alternate means of stabilizing RCS temperature or conducting a unit cooldown from the main control room is currently provided in the Emergency Operating Procedure (EOP), for events such as loss of condenser vacuum, station blackout, and LOCA cooldown with degraded HPI.

Following a SSF mitigated event that occurs during a high decay heat/low RCS temperature off-nominal plant condition, it is desirable to stabilize RCS temperature to prevent unnecessary heatup and expansion of the RCS. Procedural guidance will be provided to direct a non-licensed operator to valve in the local ADV main steam pressure gauge, establish communications with the SSF control room and, when directed by the SSF control room, slowly throttle open the 10" control valve to stabilize RCS temperature. For a SSF mitigated event that occurs at a very low initial RCS temperature, the 12" vent valve may need to be opened to achieve the desired steaming rate.

After RCS temperature has been stabilized, additional ADV operation is not anticipated as SSF letdown will be throttled to control RCS pressure. However, RCS temperature may eventually begin to slowly decrease and procedural guidance will be provided to throttle the ADVs closed to again stabilize RCS temperature.

The guidance to operate the ADVs during an off-nominal SSF event will either be added to the SSF EOP or the EOP. That decision will be made during procedure revision and validation.

RAI-5.E

The staff requests the licensee to describe the training provided regarding operator manual operation of the ADVs for plant cooldown.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs will be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occurs from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occurs from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

Non-licensed operators currently receive initial classroom training and periodic continuing classroom training on the purpose and operations of the ADVs. Non-licensed operators are required to qualify to the local operation of ADV task during on-the-job training. Non-licensed operators may be required to demonstrate proficiency in locally operating ADVs during their annual requalification exam (tasks are selected by random sampling).

License operator candidates currently receive classroom training on the purpose and operations of the ADVs during participation in the Initial License Training (ILT) program. License operator candidates receive training on directing non-licensed operators in using ADVs to cool down a unit from the main control room during ILT simulator training. License operator candidates may be required to demonstrate proficiency in locally operating ADVs during their ILT NRC exam (tasks are selected by random sampling).

Licensed operators currently receive periodic classroom training on the purpose and operations of the ADVs during participation in the Licensee Operator Requalification (LOR) program. Licensed operators periodically receive training on directing non-licensed operators in using ADVs to cool down a unit from the main control room during LOR simulator training. Licensed operators may be required to demonstrate proficiency in locally operating ADVs during their LOR annual requalification exam (tasks are selected by random sampling).

Procedural guidance and training on stabilizing RCS temperature following an off-nominal SSF mitigated event has not yet been developed. Licensed operators will receive classroom and simulator training on using the ADVs during an off-nominal SSF mitigated event to stabilize RCS temperature once this procedural guidance has been developed. This training will consist of stabilizing RCS temperature during an off-nominal SSF mitigated event as well as training on maintaining RCS temperature stable with a water solid RCS.

Classroom and simulator training on using the ADVs during an off-nominal SSF event will also be incorporated into the ILT and LOR programs.

RAI-5.F

The staff requests the licensee to describe the specific controls that facilitate the operator coordinating effectively with the SSF control room regarding RCS pressure/temperature while manual operating the ADVs to achieve plant cooldown.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated event. The ADVs may be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occurs from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occurs from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

One 12" atmospheric dump line is provided for each main steam line. This dump line contains a 1.5" hand operated atmospheric dump bypass control valve, a 10" hand operated atmospheric dump control valve and a 12" hand operated atmospheric vent valve. These three flow paths are installed in parallel and are provided with a common upstream hand operated isolation valve.

Non-licensed operators will locally operate the ADVs from the 5th floor (turbine deck) of the turbine building. The licensed operator in the SSF control room will direct operation of the ADVs. The licensed operator in the SSF control room will be in constant communications with the non-licensed operator at the ADVs using the plant radio system. The non-licensed operator will not independently operate the ADVs.

Following a SSF mitigated event that occurs during nominal plant conditions it is desirable to minimize the unnecessary cycling of the MSRVs and the non-licensed operator will be directed to slowly throttle open the 1.5" atmospheric dump bypass control valves to lower MS pressure to a value where the MSRVs remain seated. In the unlikely event that additional steam flow is required, the 10" control valve will be slowly throttled open until the MSRVs reseat.

The licensed operator in the SSF control room will monitor RCS temperature, RCS pressure, and PZR level, and will provide directions to the non-licensed operator to slowly throttle the ADVs open or closed as necessary to decrease main steam pressure until the MSRVs reseat and to maintain RCS temperature, RCS pressure and PZR level constant once the MSRVs have reseated.

Each atmospheric dump line is provided with a local main steam pressure gauge. The non-licensed operator will monitor MS pressure and communicate the value to the licensed operator in the SSF control room. MS pressure is an additional plant parameter that the SSF control room will use in directing the operation of the ADVs. The non-licensed operator will not independently operate the ADVs based on MS pressure indication.

Following a SSF mitigated event that occurs during a high decay heat/low RCS temperature off-nominal plant conditions it is desirable to stabilize RCS temperature to prevent unnecessary heatup and expansion of the RCS. Initially, the licensed operator in the main control room will be controlling RCS temperature by adjusting turbine bypass valve (TBV) position manually from the control switch. When making TBV adjustments the operator will monitor RCS temperature and pressure, PZR level and MS pressure to ensure that the desired results are achieved. Following a loss of the TBVs, non-licensed operators will be dispatched to the ADVs and will be directed by the licensed operator to slowly throttle open the 10" control valve to stabilize RCS temperature. For an off-nominal SSF event that occurs at a low initial RCS temperature use of the 12" vent valve may be required to obtain the required steaming rate.

The licensed operator in the SSF control room will monitor RCS temperature, RCS pressure, and PZR level, and provide directions to the non-licensed operator to slowly throttle the ADVs open or closed as necessary to stabilize the unit and maintain RCS temperature, pressure and PZR level constant. The non-licensed operator will also locally monitor MS pressure and communicate the value to the licensed operator in the SSF control room.

The plant radio system provides the operators with the ability to communicate throughout the auxiliary building, reactor building, SSF, turbine building and yard areas using hand held radios. The radios are used daily during plant operations and radio communication is verified between the SSF control room and the main control room weekly. The ADVs will not be operated during an SSF event unless effective communications can be established between the control room and the ADVs.

RAI-5.G

The staff requests the licensee to provide the basis and justification regarding the feasibility and validation for the operator to manually operate the ADVs to achieve plant cooldown.

Duke Energy Response

The ADVs will not be used to achieve plant cooldown during the stabilization phase of an SSF mitigated turbine building flood. The ADVs will be used to reduce main steam pressure until the MSRVs reseat following SSF mitigated events that occurs from a nominal operating condition. The ADVs may also be used to stabilize RCS temperature following SSF mitigated events that occurs from an off-nominal plant operating condition to prevent the RCS from reheating back to 550°F. During the recovery phase of an SSF mitigated event, the ADV's may be used to achieve plant cooldown as described in the Safety Evaluation Regarding Implementation of Mitigating Strategies Related to Orders EA-12-049 (ML17202U791). Oconee has not made any changes in regard to use of the ADVs during a FLEX event in preparation for the NRC TI-2515/191 inspection.

One 12" atmospheric dump line is provided for each main steam line. This dump line contains a 1.5" hand operated atmospheric dump bypass control valve, a 10" hand operated atmospheric dump control valve and a 12" hand operated atmospheric vent valve. These three flow paths are installed in parallel and are provided with a common upstream hand operated isolation valve.

Following a SSF mitigated event that occurs during nominal plant conditions it is desirable to minimize the unnecessary cycling of the MSRVs and the 1.5" atmospheric dump bypass control valves will be throttled open to lower MS pressure to a value where the MSRVs remain seated. The 1.5" bypass control valve has been designed to limit the decrease in MS pressure to a value where the MSRVs remain seated and limit the rate of steam flow, the valve will be operated slowly, and the non-licensed operator will be under the direction of a licensed operator. In the unlikely event that additional steam flow is required, the 10" control valve will be slowly throttled open until the MSRVs reseat.

Following a SSF mitigated event that occurs during a high decay heat/low RCS temperature off-nominal plant conditions it is desirable to minimize the amount of RCS inventory that must be diverted to the SFP. If adequate time and resources are available, the 10" ADV control valve will be used to stabilize RCS temperature. The 10" control valve is designed for precise throttling of steam flow in the event the turbine bypass to the condenser is unavailable. For very low steam pressures, the 12" vent valve may be opened if required to achieve the desired RCS temperature.

The 'A' and 'B' steam line ADVs are located approximately 15' apart in an accessible area on the 5th floor (turbine deck) of the turbine building and the valves are well labelled. This physical separation minimizes the possibility of the operator operating the wrong ADV.

Guidance for using the ADVs as an alternate means of stabilizing RCS temperature or conducting a unit cooldown from the main control room is currently provided in the Emergency Operating Procedure for events such as loss of condenser vacuum, station blackout, and LOCA cooldown with degraded HPI. As such, licensed operators and non-licensed operators receive initial and periodic continuing training on operation of the ADVs. The licensed operators are trained to initially operate the ADVs in small increments and wait for expected feedback before continuing. Operation of the ADVs is a required non-licensed operator qualification task.

The ADVs are stroke tested by non-licensed operators under the direction of licensed personnel at full main steam system pressure prior to each unit's refueling outage.

A unit cooldown using ADVs was successfully demonstrated on Unit 1 on February 15, 2007 (Reference LER 269/2007-01, Revision 1, dated July 2, 2007).

RAI-6 (APHB)

The staff interprets the throttling of the SSF letdown valve as a new manual operator action; however, the licensee did not explicitly identify this as a new operator action in its LAR. Therefore, the staff has developed the following RAIs.

RAI-6.A

The staff requests the licensee to describe any operator actions in addition to manual operation of the MS ADVs and manual throttling of the SSF letdown line that are associated with the proposed LAR and have not been previously reviewed and approved by the NRC.

Duke Energy Response

No additional operator actions requiring NRC review and approval have been identified. The SSF was originally licensed with a letdown line that had throttling capability. Throttling of the SSF letdown line was previously reviewed and approved (Reference NRC Safety Evaluation for the SSF dated April 28, 1983, Accession Number 8305200103). Manual throttling of the new SSF letdown line is not a new operator action.

RAI-6.B

The staff requests the licensee to provide the basis and justification regarding the feasibility and validation for any operator actions in addition to manual operation of the MS ADVs and manual throttling of the SSF letdown line that are associated with the proposed LAR and have not been previously reviewed and approved by the NRC.

Duke Energy Response

Not applicable, see response to RAI-6.A.

RAI-7 (Plant Licensing Branch II-1)

Section 50.92, "Issuance of amendment," of 10 CFR states that in determining whether an amendment to a license will be issued to the applicant, the Commission will be guided by the considerations which govern the issuance of initial licenses to the extent applicable and appropriate. Section 50.57, "Issuance of operating licenses," of 10 CFR states that an operating license may be issued by the Commission upon finding that the facility will operate in conformity with the application as amended. LAR 2017-03, Enclosure, Page 1 states:

> Modifications to the plant are also being made to provide a larger capacity SSF reactor coolant letdown line and an improved pulsation dampener for the positive displacement SSF reactor coolant makeup pump that will allow sufficient reactor coolant system letdown and makeup capability over the full range of system pressure required for TB flood mitigation. These modifications are being performed under 10 CFR 50.59; their approval is not a part of this LAR. The combination of these modifications and the proposed change to the licensing basis will resolve the existing nonconforming conditions for each Oconee unit.

Page 13 states, "Implementation of these modifications is scheduled for the fall of 2018 for Oconee Unit 1, fall of 2019 for Oconee Unit 2, and the spring of 2018 for Oconee Unit 3." In the cover letter for LAR 2017-03, the licensee requested the NRC to approve the amendment request by December 31, 2018, and stated that once approved, the licensee would implement the amendment within 90 days. The schedule for modifications for Unit 2 (i.e., the fall of 2019) would result in the requested approval and implementation dates not enabling the staff to make the 10 CFR 50.57 finding because Unit 2 would not be able to be operated in conformity with the amendments until its modifications are complete, assuming the staff can approve the amendments by December 31, 2018. Therefore, the staff requests the licensee to propose changes to the requested implementation dates or application that would enable the staff to make a finding per 10 CFR 50.57.

Duke Energy Response

ONS will not be able to meet proposed off-nominal success criteria until the modifications are complete. Duke Energy has revised the proposed UFSAR change to indicate that the proposed off-nominal success criteria are only applicable to ONS unit(s) with the SSF letdown line and SSF reactor coolant makeup pump pulsation dampener modifications complete. The revised UFSAR marked up page and retyped pages are provided in Attachments 1 and 2, respectively.

The proposed UFSAR change has also been revised to list the applicable success criteria from UFSAR Section 9.6.1 in Section 9.6.2 for the turbine building flood event occurring at nominal full power conditions. UFSAR Section 9.6.2 was revised to more clearly state the success criteria for off-nominal conditions.

RAI-8 (Environmental and NEPA Branch (MENB))

Section 5 of the LAR 2017-03 Enclosure, page 19, states, in part, "The proposed change will not change the types or amounts of any effluents that may be released offsite." Given that the licensee has requested the approval to use the MS ADVs, when available, to enhance SSF mitigation capabilities, the staff requests the licensee to address whether a situation involving a miss-operated or stuck open ADV would cause this statement to change.

Duke Energy Response

Currently, during SSF mitigated events secondary side heat removal is provided by feeding lake water into the steam generators and steaming through the MS relief valves. When steaming through the MS ADV's in lieu of the MS relief valves, the steaming (effluent) rate is expected to be similar. The ADV's are local/manually operated valves with a chain operator. Misoperation is highly unlikely given the monitoring provided by control room personnel and the availability of local pressure indication. In the unlikely event of a stuck open ADV, the affected steam generator would eventually depressurize allowing the ADV block valve to be closed. While pressure in the affected steam generator reduces, the feed and/or steaming rate of the unaffected steam generator would be reduced to compensate, thus no significant net change in effluent is expected.

ATTACHMENT 1

UFSAR MARKED-UP PAGES

To verify SSF performance criteria, thermal-hydraulic (T/H) analysis was performed to demonstrate that the SSF can achieve and maintain safe shutdown following postulated turbine building floods. The analysis evaluates RCS subcooling margin using inputs that are representative of nominal full power end of cycle plant conditions. The analysis uses an initial core thermal power of 2619 MWth (102% of 2568 MWth) and accounts for 24-month fuel cycles. The consequences of the postulated loss of main and emergency feedwater were analyzed as a RCS overheating scenario. For the examined overheating scenario, an important core input is decay heat. High decay heat conditions were modeled that were reflective of maximum, end of cycle conditions. The high decay heat assumption was confirmed to be bounding with respect to the RCS subcooling response. The results of the nominal case analysis demonstrate that the SSF is capable of meeting

"event", and thus need not be postulated concurrent with non-fire-related failures in safety systems, other plant accidents, or the most severe natural phenomena (Reference 31).

Deleted Paragraph(s) per 2015 update.

Deleted Paragraph(s) per 2012 upd

: 1) maintain a minimum water level above the reactor core, 2)

TURBINE BUILDING FLOOD EVE

The Turbine Building Flood was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to maintain the reactor in a safe shutdown condition for a period of 72 hours following a TB Flood. No other concurrent event is assumed to occur. The success criteria for this event ~~is to~~ assure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling~~. The reactor shall be maintained at least 1% Δk/k~~ with the most reactive rod fully withdrawn. (Reference 1, 10)

, 3) transfer decay heat to an ultimate heat sink, and 4) maintain the reactor at least 1% Δk/k shutdown

SECURITY-RELATED EVENT

A Security Related Event was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to achieve and maintain a safe shutdown condition for this event. No other concurrent event is assumed to occur. (Reference 1) The success criteria for

Off nominal success criteria are only applicable to unit(s) with the SSF letdown line and SSF RC makeup pump pulsation dampener modifications complete.

In addition to the nominal case analysis described above, off-nominal cases with low decay heat, low initial power and low initial temperature were analyzed. In each of these off-nominal cases, the results demonstrate that the SSF continues to meet the following success criteria for this event: 1) maintain a minimum water level above the reactor core, 2) transfer decay heat to an ultimate heat sink, and 3) maintain the reactor at least 1% Δk/k shutdown with the most reactive rod fully withdrawn.

During periods of very low decay heat the SSF will be used to establish conditions that support the formation of subcooled natural circulation between the core and the SGs; however, natural circulation involving the SGs may not occur if the amount of decay heat available is less than or equal to the amount of heat removed by ambient losses to containment and/or by other means, e.g., letdown of SSF reactor coolant makeup. When these heat removal mechanisms are sufficient to remove core decay heat, they are considered adequate to meet the core cooling function and systems supporting SG decay heat removal, although available, are not necessary for core cooling.

A nominal full power condition is defined as a unit at 100% power for approximately 4 days of operation which provides the decay heat required to meet the nominal SSF success criteria. Regarding operation in MODES 1, 2, and 3 at other than nominal full power, T-H analyses demonstrate that the SSF maintains conditions that support the formation of subcooled natural circulation between the core and SGs such that there is no water relief through the pressurizer safety valves.

Regarding operation at low initial temperature, T-H analyses demonstrate that in some cases pressurizer level was not maintained on scale; however, conditions that support the formation of subcooled natural circulation between the core and the SGs were maintained. In cases where the pressurizer did go water-solid, there was no liquid relief through the pressurizer safety valves.

ATTACHMENT 2

UFSAR RETYPED PAGES

250°F with a long term strategy for reactivity, decay heat removal and inventory/pressure control. Long-term subcooled natural circulation decay heat removal is provided by supplying lake water to the steam generators and steaming to atmosphere. The extended coping period at these conditions is based on the significant volume of water available for decay heat removal and reduced need for primary makeup to only match nominal system losses. A stuck rod is not required to be postulated for this event. Initial conditions are 100% power with sufficient decay heat such that natural circulation can be achieved. The hypothesized fire is to be considered an "event", and thus need not be postulated concurrent with non-fire-related failures in safety systems, other plant accidents, or the most severe natural phenomena (Reference 31).

Deleted Paragraph(s) per 2015 update.

Deleted Paragraph(s) per 2012 update.

TURBINE BUILDING FLOOD EVENT

The Turbine Building Flood was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to maintain the reactor in a safe shutdown condition for a period of 72 hours following a TB Flood. No other concurrent event is assumed to occur. To verify SSF performance criteria, thermal-hydraulic (T/H) analysis was performed to demonstrate that the SSF can achieve and maintain safe shutdown following postulated turbine building floods. The analysis evaluates RCS subcooling margin using inputs that are representative of nominal full power end of cycle plant conditions. The analysis uses an initial core thermal power of 2619 MWth (102% of 2568 MWth) and accounts for 24-month fuel cycles. The consequences of the postulated loss of main and emergency feedwater were analyzed as a RCS overheating scenario. For the examined overheating scenario, an important core input is decay heat. High decay heat conditions were modeled that were reflective of maximum, end of cycle conditions. The high decay heat assumption was confirmed to be bounding with respect to the RCS subcooling response. The results of the nominal case analysis demonstrate that the SSF is capable of meeting the success criteria for this event: 1) maintain a minimum water level above the reactor core, 2) assure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling, 3) transfer decay heat to an ultimate heat sink, and 4) maintain the reactor at least 1% $\Delta k/k$ shutdown with the most reactive rod fully withdrawn. (Reference 1, 10)

<u>Off nominal success criteria are only applicable to unit(s) with the SSF letdown line and SSF RC makeup pump pulsation dampener modifications complete.</u>

In addition to the nominal case analysis described above, off-nominal cases with low decay heat, low initial power and low initial temperature were analyzed. In each of these off-nominal cases, the results demonstrate that the SSF continues to meet the following success criteria for this event: 1) maintain a minimum water level above the reactor core, 2) transfer decay heat to an ultimate heat sink, and 3) maintain the reactor at least 1% $\Delta k/k$ shutdown with the most reactive rod fully withdrawn.

During periods of very low decay heat the SSF will be used to establish conditions that support the formation of subcooled natural circulation between the core and the SGs; however, natural circulation involving the SGs may not occur if the amount of decay heat available is less than or equal to the amount of heat removed by ambient losses to containment and/or by other means, e.g., letdown of SSF reactor coolant makeup. When these heat removal mechanisms are sufficient to remove core decay heat, they are considered adequate to meet the core cooling function and systems supporting SG decay heat removal, although available, are not necessary for core cooling.

A nominal full power condition is defined as a unit at 100% power for approximately 4 days of operation which provides the decay heat required to meet the nominal SSF success criteria. Regarding operation in MODES 1, 2, and 3 at other than nominal full power, T-H analyses demonstrate that the SSF maintains conditions that support the formation of subcooled natural circulation between the core and SGs such that there is no water relief through the pressurizer safety valves.

Regarding operation at low initial temperature, T-H analyses demonstrate that in some cases pressurizer level was not maintained on scale; however, conditions that support the formation of subcooled natural circulation between the core and the SGs were maintained. In cases where the pressurizer did go water-solid, there was no liquid relief through the pressurizer safety valves.

SECURITY-RELATED EVENT

A Security Related Event was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to achieve and maintain a safe shutdown condition for this event. No other concurrent event is assumed to occur. (Reference 1) The success criteria for this event is to assure the core will not return to criticality, the active fuel will not be uncovered, and long-term natural circulation will not be halted. (Reference 41)

STATION BLACKOUT EVENT

This event was licensed after the design of the SSF was completed and approved by NRC. The SSF was credited as the method the plant would employ to mitigate a SBO event. (References 38 and 39) The success criteria is to maintain the core covered for 4 hours. No stuck rod is assumed for this event. Initial conditions are 100% power and 100 days of operation. (Reference 40)

SSF TORNADO DESIGN CRITERIA

This is a design criterion for the SSF that was committed to as part of the original SSF licensing correspondence. All parts of the SSF itself that are required for mitigation of the SSF events are required to be designed against tornado winds and associated tornado missiles. This requirement is satisfied through appropriate design of the SSF structure. This requirement does not extend to SSCs that were already part of the plant which SSF relies upon and interfaces with for event mitigation. It is important to note that the SSF was not licensed to mitigate a tornado event or a tornado missile event (Reference 1). Tornado design requirements for the plant itself are addressed in Section 3.2.2. A subsequent issue related to crediting SSF ASW as an alternative for EFW tornado missile protection vulnerabilities is discussed below (see EFW Tornado Missile Design Criteria).

EFW SEISMIC DESIGN CRITERIA (GL 81-14)

During the seismic qualification review of the Oconee EFW system in the 1980s, the NRC postulated that a seismic event could break a pipe and potentially cause a flood of the turbine building thereby submerging and failing the EFW pumps. The NRC wanted to ensure that the EFW System was seismically designed and could withstand a single failure, as well. As an alternative to upgrading the EFW System, NRC credited the use of the SSF ASW System and HPI Feed & Bleed (Reference 34). These two decay heat removal systems are seismically designed and independent from each other. The event postulated by GL 81-14 (a seismic break) was a special condition imposed on ONS to evaluate the EFW design. It was not intended to re-define the SSF mitigated TB Flood (which does not concurrently consider a seismic event, nor does it impose a single failure). Although both "events" are TB Floods, they are two separate licensing actions with different scopes, different acceptance criteria, and different purposes. The GL 81-14 flood does not have specified initial conditions, other mitigation assumptions, or success criteria to be considered because it is not an event, only an EFW design criterion (Reference 34).