Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

CNL-16-105

June 24, 2016

10 CFR 50.90

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

Browns Ferry Nuclear Plant, Units 1, 2, and 3
Renewed Facility Operating License Nos. DPR-33, DPR-52, and DPR-68
NRC Docket Nos. 50-259, 50-260, and 50-296

Subject: **Proposed Technical Specifications (TS) Change TS-505 - Request for License Amendments - Extended Power Uprate (EPU) - Supplement 22, Responses to Requests for Additional Information**

References:
1. Letter from TVA to NRC, CNL-15-169, "Proposed Technical Specifications (TS) Change TS-505 - Request for License Amendments - Extended Power Uprate (EPU)," dated September 21, 2015 (ML15282A152)

2. Letter from NRC to TVA, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Request for Additional Information Related to License Amendment Request Regarding Extended Power Uprate (CAC Nos. MF6741, MF6742, and MF6743)," dated June 13, 2016 (ML16146A635)

By the Reference 1 letter, the Tennessee Valley Authority (TVA) submitted a license amendment request (LAR) for the Extended Power Uprate (EPU) of Browns Ferry Nuclear Plant (BFN) Units 1, 2 and 3. The proposed LAR modifies the renewed operating licenses to increase the maximum authorized core thermal power level from the current licensed thermal power of 3458 megawatts to 3952 megawatts. The Reference 2 letter provided Nuclear Regulatory Commission (NRC) Requests for Additional Information (RAIs) SCVB-RAIs 2, 3, 4, 5, 6, 7, 9, 10, 11, 12, 13, 15, 16, 17, 18, 19, 20, 21, 22, 23, 27, 28, 29, 31, and 33 with a due date of June 24, 2016. The enclosure to this letter provides the responses to these RAIs from the Reference 2 letter. The responses to the remaining RAIs from the Reference 2 letter will be submitted to NRC by July 25, 2016.

TVA has reviewed the information supporting a finding of no significant hazards consideration and the environmental consideration provided to the NRC in the Reference 1 letter. The supplemental information provided in this submittal does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration. In addition, the supplemental information in this submittal does not affect the bases for concluding that neither an environmental impact statement nor an environmental assessment needs to be prepared in connection with the proposed license amendment. Additionally, in accordance with 10 CFR 50.91(b)(1), TVA is sending a copy of this letter to the Alabama State Department of Public Health.

There are no new regulatory commitments associated with this submittal. If there are any questions or if additional information is needed, please contact Mr. Edward D. Schrull at (423) 751-3850.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 24th day of June 2016.

Respectfully,

for

J. W. Shea
Vice President, Nuclear Licensing

Enclosure: Responses to NRC Requests for Additional Information SCVB-RAIs 2, 3, 4, 5, 6, 7, 9, 10, 11, 12, 13, 15, 16, 17, 18, 19, 20, 21, 22, 23, 27, 28, 29, 31, and 33

cc:

NRC Regional Administrator - Region II
NRC Senior Resident Inspector - Browns Ferry Nuclear Plant
State Health Officer, Alabama Department of Public Health (w/o Enclosure)

ENCLOSURE

Responses to NRC Requests for Additional Information
SCVB-RAIs 2, 3, 4, 5, 6, 7, 9, 10, 11, 12, 13, 15, 16, 17, 18, 19, 20, 21, 22, 23, 27, 28, 29, 31, and 33

ENCLOSURE

SCVB-RAI 2

In Reference 2 (Power Uprate Safety Analysis Report (PUSAR)), Table 2.6-5, Note 3 states:

> *The larger drywell volume of 171,000 ft^3 [cubic feet] (compared to the minimum DW [drywell] volume of 159,000 ft^3 (See Table 2.6-2a) results in a larger initial drywell non-condensable gas mass and more non-condensable gas transferred to the wetwell during a LOCA [loss-of-coolant accident]. This maximizes the wetwell and drywell pressure and is conservative.*

The above statement provides a qualitative justification for a higher drywell pressure response for a larger drywell volume. For the short term drywell pressure response, it would seem that using the larger drywell volume of 171,000 ft^3 would result in a less limiting pressure response than using the minimum volume of 159,000 ft^3. Confirm that maximum drywell and wetwell pressure response mentioned above (using the larger drywell volume of 171,000 ft^3) was obtained by a sensitivity analysis performed using the LAMB and M3CPT computer codes for drywell volumes of 171,000 ft^3 and 159,000 ft^3 using same assumptions and same remaining input parameters.

TVA Response:

The use of the larger initial drywell volume for peak containment pressure response is based on the understanding of the Design Basis Accident (DBA)-Loss of Coolant Accident (LOCA) progression and the GE Hitachi (GEH) pressure suppression containment design, and was based on the sensitivity studies from another GEH Mark I containment plant similar to the Browns Ferry Nuclear Plant (BFN) design. There was no sensitivity analysis performed particularly for the BFN PUSAR regarding the initial drywell volume.

As described by the PUSAR statement, a larger initial drywell volume results in a larger initial non-condensible gas mass in the drywell that is available for transfer to the wetwell. Therefore, the assumption of a larger initial drywell volume is more conservative for calculating peak drywell pressure.

A smaller drywell volume would result in a faster initial drywell pressurization rate and higher predicted drywell pressures very early in the event during the period prior to and shortly after vent clearing. However, the short-term drywell pressure peaks later, after most drywell gas is transferred from the drywell. The transfer of drywell gas to the wetwell pressurizes the wetwell and produces a pressure feedback effect on drywell pressure due to the effect of the higher wetwell pressure on vent flow. Therefore, although a higher initial drywell volume will produce a lower initial pressurization rate in the first few seconds of the event, it will produce the maximum predicted peak drywell pressure.

In response to this RAI, a sensitivity run was made for the design case in Table 2.6-1 of Reference 1 (PUSAR) by changing only the initial drywell volume from 171,000 ft^3 to 159,000 ft^3. The comparison of drywell pressures for those two cases is shown in Figure SCVB-RAI 2-1, which is consistent with the discussion given above. For the case at design conditions in Table 2.6-1, the initial drywell volume is 171,000 ft^3 and the peak DW pressure is 50.9 psig. The peak DW pressure is 50.3 psig with a smaller drywell initial volume of 159,000 ft^3.

Reference

1. GE Hitachi Nuclear Energy, “Safety Analysis Report for Browns Ferry Nuclear Plant Units 1, 2 and 3 Extended Power Uprate,” NEDC-33860P, September 2015.

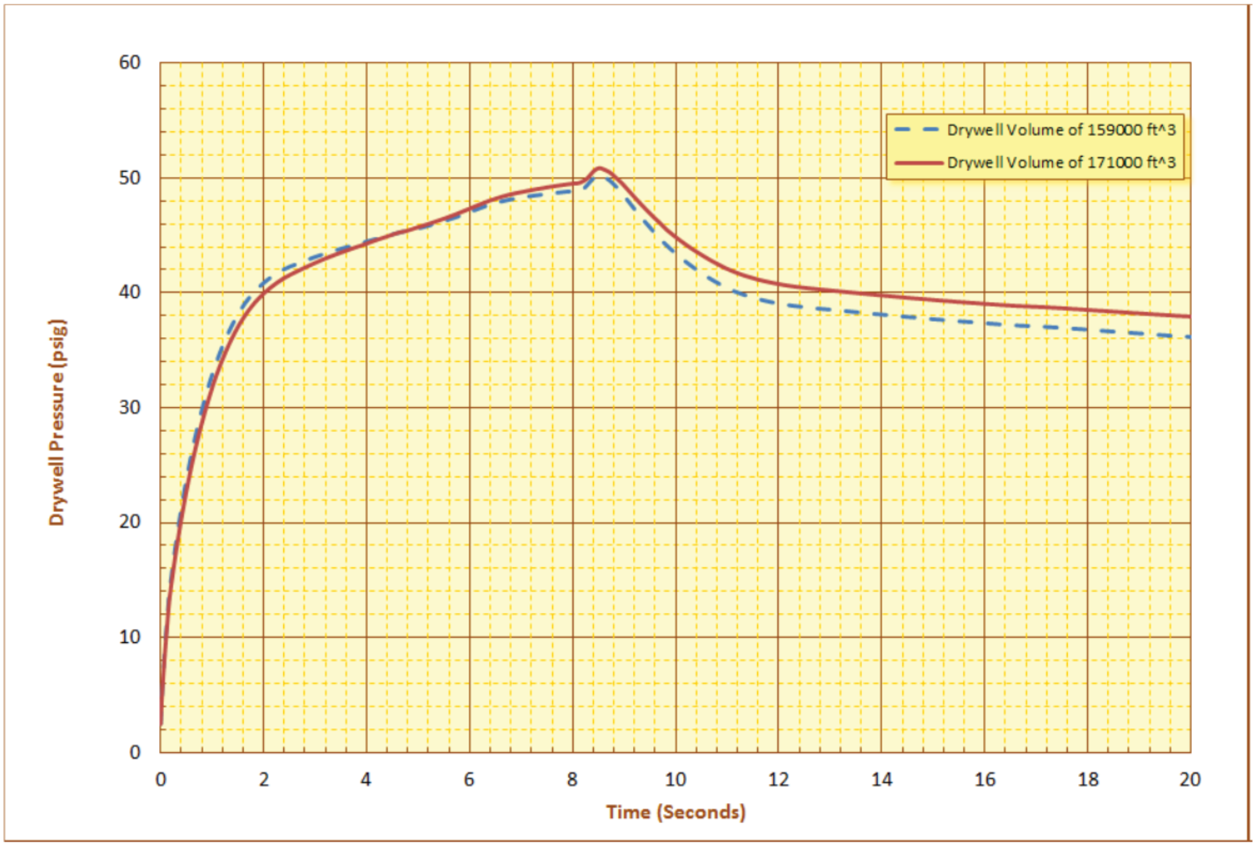

Figure SCVB-RAI 2-1
Comparison of EPU Short-Term Recirculation Suction Line Break DBA-LOCA Containment Pressure Responses
(Design Condition: Initial DW Temperature =70ºF)
The case identified by the solid curve is the same case in Reference 1, Figure 2.6-7.

SCVB-RAI 3

Reference 1, Enclosure, Section 3.2 states:

> *The elimination of CAP [Containment Accident Pressure] credit from the licensing basis is accomplished through system modifications and analytical assumption changes that are factored into the safety analyses.*
>
> *TVA is proposing a modification to increase the isotopic B-10 [boron-10] enrichment provided by the SLC [Standby Liquid Control] System. Raising the boron-10 enrichment for EPU [extended power uprate] increases the rate of negative reactivity inserted by the SLC system and results in a faster shut down of the reactor during the ATWS [Anticipated Transient Without Scram] event. This results in a reduced heat load input into the suppression pool; therefore, the suppression pool temperature is lower.*

*Describe all system modifications, in particular system **hardware** [emphasis added] modifications, performed for elimination of CAP credit for the available Net Positive Suction Head (NPSH) analysis for the Residual Heat Removal (RHR) and Core Spray (CS) pumps other than the change in the RHR heat exchanger K-values described in Reference 5, and the increase in isotopic B-10 enrichment provided by the SLC system.*

TVA Response:

The only system modifications or hardware modifications performed for elimination of CAP credit for the available NPSH analysis for the RHR and CS pumps are the change in the RHR heat exchanger K-values described in EPU LAR Attachment 39 and the increase in isotopic B-10 enrichment provided by the SLC system.

SCVB-RAI 4

Table 2.6-2a of PUSAR does not provide the assumptions for the initiation of feedwater (FW) flow isolation time and the valve closure time for the suppression pool temperature response analysis.

Updated Final Safety Analysis Report (UFSAR) Section 14.11.3.3.1, item f provides the FW flow assumption for the current Recirculation Suction Line Break (RSLB) Design Basis (DB) LOCA licensing basis analysis as follows:

> *The feedwater flow was assumed to stop instantaneously at time zero. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby reducing the discharge of steam and water into the primary containment.*

Section 14.11.5.1.1 of UFSAR, item j provides the FW flow assumption for the current main steamline break LOCA licensing basis analysis as follows:

> *Feedwater flow is assumed to decrease linearly to zero over the first four seconds to account for the slowing down of the turbine-driven feed pumps in response to the rise in reactor vessel water level.*

State the assumption for the EPU analysis that was used for feedwater isolation for the short and long term suppression pool temperature response analyses and how does it differ from the current licensing basis analysis. Provide justification in case the conservatism in the EPU analysis is reduced.

TVA Response:

It should be noted that the cited UFSAR sections for the FW flow assumption (UFSAR Section 14.11.3.3.1 for the RSLB DBA-LOCA and Section 14.11.5.1.1 for the Main Steam Line Break (MSLB) outside containment) do not reflect the effects from power uprate to the BFN current licensed thermal power (CLTP) of 3458 MWt.

UFSAR Section 14.6.3.3.1, items e. and f. describe the FW flow assumptions for the DBA-LOCA short-term containment response and the DBA-LOCA long term containment response as follows:

e. For the short term containment response analysis, the feedwater flow is assumed to coast down to zero at four seconds into the event. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby, reducing the discharge of steam and water into the primary containment.

f. For the long term containment response analysis, the reactor feedwater flow into the reactor continues until all the high energy feedwater (water that would contribute to heating the pool) is injected into the vessel.

UFSAR Section 14.6.5 provides input assumptions related to an MSLB outside the secondary containment. This analysis contains assumptions that are designed to maximize the radiological release to the environment. Because this event does not result in break flow into the primary containment, the effect on the primary containment response is non-limiting for the containment pressure response. In addition, because the initial mass and energy release of the MSLB (prior to main steam isolation valve closure) is outside the containment, the primary containment response, i.e., peak suppression pool (SP) temperature, is bounded by the small steam line break analysis performed at EPU conditions.

The BFN EPU License Amendment Request (LAR) Attachment 6 (PUSAR) Table 2.6-5 provides a comparison of the inputs and assumptions used for the DBA-LOCA short-term (M3CPT with LAMB break flow) containment analysis. As shown in Table 2.6-5, the FW flow is assumed to coast down to zero at four seconds into the event for both the current design analysis and the EPU analysis.

Table 2.6-6 of the PUSAR provides a comparison of the inputs and assumptions for the limiting long term SP temperature response performed with the GEH SHEX code. As shown in Table 2.6-6 and Note 2 of the table, the BFN EPU analysis uses a more conservative assumption for FW flow than the current design analysis. Note that this EPU FW flow assumption is used for the EPU long-term DBA-LOCA containment analysis as well as the limiting (for SP temperature response) small steam break analyses. The EPU analysis assumption for the FW response is conservative because it results in more heat added to the reactor pressure vessel and subsequently to the SP prior to the SP temperature reaching its peak value. The EPU assumption is also consistent with the current GEH containment analysis procedure.

SCVB-RAI 5

Refer to Section 2.6.3.1.1 of PUSAR third paragraph; explain the basis for assuming the LOCA signal (high drywell pressure concurrent with low reactor pressure vessel (RPV) pressure) occurs in the accident unit 10 minutes after the accident initiation in the small steam line break (SSLB) accident analysis.

TVA Response:

The assumption that the LOCA signal (high drywell (DW) pressure concurrent with low RPV pressure) occurs in the accident unit 10 minutes after the accident initiation in the small steam line break (SSLB) accident analysis is based on a series of sensitivity studies performed by GEH during the development of Safety Communication (SC) 11-10 (Reference 1). This 10 minute assumption for the LOCA initiation time coupled with an assumed operator action time of ten minutes to transfer Residual Heat Removal (RHR) from core cooling mode to containment cooling mode were considered in Reference 1 as conservative to determine the impact of delaying RHR drywell spray initiation on the containment response for the affected plants, which include BFN.

As stated in the Background section of Reference 1, containment analyses prior to Reference 1 typically assumed that the LOCA initiation signal during a small break LOCA occurred early in the event on high drywell pressure. The current design and licensing basis containment analyses for BFN also assume that manual operator actions for shifting the operation of RHR from core cooling mode (low pressure coolant injection (LPCI)) to containment cooling mode would not occur until 10 minutes after the event initiation.

The sensitivity studies performed in the development of Reference 1 showed that, for larger break sizes (break sizes greater than 0.25 ft^2), the reactor pressure vessel (RPV) will depressurize rapidly (on the order of two to four minutes) to below the RPV pressure that completes the high drywell pressure/Low RPV pressure LOCA initiation signal. The BFN EPU containment response analyses for these larger break sizes confirmed that the BFN RPV depressurization time to low RPV pressure is consistent with the sensitivity studies. Therefore, the assumption that the LOCA signal (high drywell pressure concurrent with low RPV pressure) occurs in the accident unit 10 minutes after the accident initiation is conservative because this assumption coupled with an assumed operator action time of ten minutes to shift RHR from core cooling mode to containment cooling mode results in a longer delay for initiating containment spray and a more severe drywell temperature response. The BFN operators would be directed to shift RHR from core cooling mode to containment cooling mode by BFN Emergency Operating Instruction (EOI)-2, Primary Containment Control. The procedural steps for transferring RHR from core cooling mode to containment cooling mode are contained in BFN EOI Appendices 17A, 17B and 17C.

The sensitivity studies performed in the development of Reference 1 showed that, for smaller break sizes (break sizes less than or equal to 0.25 ft^2), the RPV will depressurize slowly (on the order of 15 minutes to greater than one hour) to below the RPV pressure that completes the high drywell pressure/Low RPV pressure LOCA initiation signal. The BFN EPU containment response analyses for these break sizes showed that the BFN RPV depressurization time to low RPV pressure is actually longer than the times in the sensitivity studies. For BFN, the operators would recognize that a LOCA signal will occur as the RPV pressure decreases to the RPV pressure for initiating a LOCA signal and would inhibit the late LOCA signal. This LOCA signal inhibit is performed by the operation of permanently installed hand switches in the BFN main control room which is a normal action per BFN procedures to prevent the generation of a LOCA signal that could result in interruption of containment cooling when core cooling has already been confirmed. The assumption in the BFN EPU containment response analysis that the LOCA signal (high drywell pressure concurrent with low RPV pressure) occurs in the accident unit 10 minutes after the accident initiation for break sizes greater than 0.10 ft^2 is conservative, because this assumption coupled with an assumed operator action time of ten minutes to shift RHR from core cooling mode to containment cooling mode results in a longer delay for initiating containment spray and a more severe drywell temperature response. The BFN operators will be directed to shift RHR from core cooling mode to containment cooling mode by BFN EOI-2, Primary Containment Control. The procedural steps for transferring RHR from core cooling mode to containment cooling mode are contained in BFN EOI Appendices 17A, 17B and 17C. For the smallest break size (0.01 ft^2), the BFN EPU containment response analysis assumes that there is no additional ten minute delay for initiating containment spray due to the generation of a high drywell pressure/low RPV pressure LOCA signal occurring at ten minutes following the event initiation because the operator has time to override the LOCA signal. Wetwell and drywell spray initiation for the 0.01 ft^2 break size is governed by the BFN EOI-2 entry conditions for initiating spray. BFN EOI-2 directs the operator to initiate wetwell spray before suppression chamber (torus) pressure rises to 12 psig and directs the operator to initiate drywell spray before drywell temperature rises to 280°F. The BFN EPU containment analysis for the 0.01 ft^2 break delayed the initiation of drywell spray until drywell temperature reached 280°F, approximately 1600 seconds after event initiation. The BFN EPU containment analysis for the 0.01 ft^2 break conservatively delayed initiation of wetwell spray initiation until 1200 seconds even though the suppression chamber (torus) pressure will exceed 12 psig by 600 seconds.

The BFN EPU analysis for the limiting break (break that resulted in the peak drywell temperature) size of 0.25 ft^2 shows that RPV depressurizing to below the RPV pressure that completes the high drywell pressure/low RPV pressure LOCA initiation signal occurs at approximately eight minutes following the event initiation. The BFN EOI-2 entry condition for drywell spray initiation occurs before ten minutes; however credit for operator action to initiate drywell spray is not taken prior to ten minutes. To conservatively maximize the time delay to drywell spray initiation, the containment response analysis assumes that the completed LOCA signal (high drywell pressure plus low RPV pressure) occurs at ten minutes, concurrent with the time that operator action to initiate drywell spray would have been assumed. The containment analysis then assumes that the operators require ten minutes following the LOCA signal to ultimately shift RHR from core cooling (LPCI mode) to containment cooling mode. For BFN, this operator action can be completed in significantly less time, i.e., in approximately five minutes. Therefore, the assumption that the LOCA signal (high drywell pressure concurrent with low RPV pressure) occurs in the accident unit 10 minutes after the accident initiation in the small steam line break (SSLB) accident coupled with an assumed operator action time of 10 minutes is conservative for determining the containment response. The BFN operators will be directed to shift RHR from core cooling mode to containment cooling mode by BFN EOI-2, Primary Containment Control. The procedural steps for transferring RHR from core cooling mode to containment cooling mode are contained in BFN EOI Appendices 17A, 17B and 17C.

It should be noted that the drywell temperature spikes shown after approximately 2000 seconds in Figure 1 of Reference 1 would not occur for BFN. The temperature spikes shown in Figure 1 of Reference 1 were the results of sensitivity studies that assumed interruption of containment cooling late in the small steam break event timeline due to the generation of high drywell pressure/low RPV pressure LOCA signals. As discussed previously, the BFN operators would recognize that a LOCA signal will occur as the RPV pressure decreases to the RPV pressure for initiating a LOCA signal and would inhibit the late LOCA signal.

Reference

1. GE Nuclear Energy, Safety Communication (SC) 11-10, "Interruption/Delay in RHR Drywell Spray Initiation," November 14, 2011.

SCVB-RAI 6

Section 2.6.5.1 of PUSAR under the heading "Suppression Pool Temperature Response – recirculation discharge line (RDLB) LOCA" states: "(break area 4.2 ft^2 [square feet] for the RSLB versus 1.94 ft^2 for the RDLB)." The RSLB break area does not match with the break flow area given in Table 2.6-5; explain.

TVA Response:

Table 2.6.5 provides inputs and assumptions for the short-term containment response performed with the M3CPT and LAMB codes. The short-term analysis is focused on determining the containment pressure response in the first 30 seconds following an RSLB DBA-LOCA. The containment pressure response is maximized by using conservatively high values for the mass and energy release from the assumed double-ended guillotine break of the recirculation suction line. In order to maximize the mass and energy release, the break area is assumed as twice (2X) the area of the recirculation suction line reactor pressure vessel nozzle (3.668 ft^2), i.e., the break flow area from each side of the broken pipe is assumed as the area of the recirculation suction line nozzle. This break flow area value is conservatively high because break flow from one side of the broken recirculation suction line pipe would be restricted by the flow area of the jet pump nozzles.

The evaluation of the RSLB DBA-LOCA contained in PUSAR Sections 2.6.1.1.1.1 and 2.6.5.1 is performed using the SHEX code and is focused on the long-term suppression pool temperature response. In this long-term analysis, a more realistic but still conservative RSLB break flow area is assumed because flow from one side of the broken recirculation suction pipe would be restricted by the area restriction of the jet pumps. The flow area for the RSLB DBA-LOCA in the containment long-term analysis is the sum of the recirculation suction line area (3.668 ft^2 or one side of the broken pipe) plus the jet pump throat area of 10 jet pump nozzles (0.548 ft^2 for the other side of the broken pipe). There are ten single-nozzle jet pumps in each reactor recirculation loop.

ENCLOSURE

SCVB-RAI 7

Section 2.6.5.1 of PUSAR, third paragraph under heading "Suppression Pool Temperature Response –Small Steam [Steamline] Break LOCA" does not distinctly state the assumed sequence of events and operator actions for the following analyses: (a) 0.01 ft^2 SSLB with HPCI available, (b) 0.01 ft^2 SSLB with HPCI not available, (c) greater than 0.01 ft^2 small steam line break with HPCI available, and (d) greater than 0.01 ft^2 SSLB with HPCI not available. State the assumed sequence including the timing of operator actions for each of these analyses. Include answers to the following question in the response.

(a) At what time from the accident initiation would the low pressure emergency core cooling system (ECCS) (i.e., RHR and CS) pumps automatically start operating, and would they operate in a low bypass flow return to the suppression pool, and for how long?

(b) The starting of HPCI (for HPCI-available case), CS, and RHR is automatic according to their start logic and loading sequence. HPCI being a high pressure system would be replenishing RPV inventory earlier. State at what time in the sequence would the RHR and CS pumps supply water to the RPV? In the analysis, do HPCI, RHR and CS systems supply water simultaneously for some period, if so, for how much time?

(c) What are the containment and RPV conditions when the operator would initiate RHR system in the drywell and wetwell spray mode?

(d) For breaks greater than 0.01 ft^2, from what point in time and sequence in the event the drywell and wetwell spray is delayed by 1200 seconds to address the concern related to ECCS interruption?

(e) For breaks greater than 0.01 ft^2, explain how the delaying of drywell and wetwell spray initiation by up to 20 minutes will address the concern related to ECCS interruption caused by a subsequent LOCA signal (activated on high drywell pressure concurrent with low RPV pressure).

(f) Are the sequence of events assumed in the analyses consistent with the emergency operating procedures for breaks less than and greater than 0.01 ft^2.

(g) Since the sequence of events assumed in the analysis differs for breaks less than and greater than 0.01 ft^2, are there different emergency operating procedures for less than and greater than 0.01 ft^2 breaks? How would the operator know whether the break is less than or greater than 0.01 ft^2.

TVA Response:

For small steam line breaks (SSLB) discussed in Section 2.6.5.1 of the PUSAR (Reference 1), the overall event sequence is shown below:

1. The plant is operating at 102% of 3952 MWt (i.e., 4031 MWt) when a steam line break occurs. There is also a concurrent loss of offsite power and only minimum diesel power is available. A single failure of one emergency diesel generator (EDG) is assumed. This allows only the starting of three residual heat removal (RHR) and three core spray (CS) pumps on the accident unit. Reactor scrams.

2. The MSIVs start closing at 0.5 seconds and close completely at 3.5 seconds.

3. If HPCI is available, it is assumed to take suction from the suppression pool (SP) and will automatically start on either high drywell (DW) pressure or low RPV Level 2 and will remain available for the duration of the event until RPV pressure is below 55 psig. If HPCI is not available, it is assumed to be unavailable from the beginning of the event.

4. At 10 minutes into the event, operators secure one RHR pump and one CS pump. The two remaining RHR pumps are also stopped[1] and prepared to be aligned in the containment spray mode. The two remaining CS pumps continue operating.

5. Operators initiate RPV depressurization at a rate of 100ºF /hour with manual operation of SRVs when suppression pool temperature reaches 120ºF. RPV depressurization is completed when RPV pressure reaches 50 psig and maintained at 50 psig afterwards.

6. Wetwell spray can be actuated 60 seconds after the DW pressure exceeds 17.1 psia. DW spray can be initiated when the DW temperature exceeds 280ºF. However, to address concerns related to RHR interruption on high DW pressure with low RPV pressure ECCS LOCA signal, the operators initiate wetwell and drywell spray no sooner than 20 minutes into the event for any break.

Tables SCVB-RAI 7-1 and SCVB-RAI 7-2 show the event time sequences for all steam line breaks analyzed in Reference 1. Table SCVB-RAI 7-1 is for the breaks with HPCI unavailable and with initial DW temperature of 70ºF; Table SCVB-RAI 7-2 is for the breaks with HPCI available and with initial DW temperature of 70ºF. The operator actions for the events are highlighted in gray. Note that the cases with HPCI available are only performed for the two limiting breaks (0.01ft^2 is the limiting break for peak suppression pool (SP) temperature; 0.25ft^2 is the limiting case for DW temperature).

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1 In actual plant operation, during a postulated accident, the operator would shut the LPCI injection valves and open the containment spray valves to align the RHR pumps in containment spray mode. The RHR pumps would not be stopped. As modeled in the analysis, pump heat for the two stopped RHR pumps is not included during the period between 600 seconds, when the pumps are stopped in the analysis, and the time containment spray is started.

However, not including RHR pump heat for this relatively small time period after 600 seconds will not impact the peak predicted DW temperature and have insignificant impact on the predicted peak pool temperature.

It is acknowledged that the operator would not align the RHR pumps into any kind of containment cooling until containment sprays are initiated in the current model. For the cases for which the interruptions of RHR pump due to the signal caused high DW pressure and low RPV pressure, the current modeling faithfully modeled the scenario, but did not model the RHR pump heat from 600 seconds to 1200 seconds, which has insignificant impact on peak pool temperatures for those cases. For the smallest break (0.01 ft^2), the limiting case for pool temperature, no interruption is modeled (for DW spray only; WW spray is modeled conservatively by delaying it until 1200 seconds). From 600 seconds until the initiations of containment sprays, no RHR cooling was modeled either. Because there is no interruption in RHR cooling for this case, the use of RHR in containment pool cooling could have been assumed from 10 minutes into the event until predicted plant conditions required the use of containment spray. However, RHR pool cooling after 10 minutes was not modeled for conservatism. There is a net conservatism for this case of not including RHR pump heat and not modeling RHR pool cooling during this time period because the heat removed by the RHR in pool cooling mode would be much greater than the heat added to the pool by RHR pump heat.

Table SCVB-RAI 7-1
Event Sequences for Browns Ferry SSLB with HPCI Unavailable

Items	$0.01 ft^2$	$0.05 ft^2$ (d)	$0.10 ft^2$ (d)	$0.25 ft^2$ (d)	$0.50 ft^2$ (d)	$1.0 ft^2$ (d)
Steam line break occurs. Loss of Offsite Power. Reactor scrams. (seconds)	0	0	0	0	0	0
MSIV starts to close. (seconds)	0.5	0.5	0.5	0.5	0.5	0.5
MSIV is fully closed. (seconds)	3.5	3.5	3.5	3.5	3.5	3.5
Three CS started automatically injection on high DW pressure or low RPV water level with time delay. (Notes (a) and (b)) (seconds)	68	68	68	68	68	68
Three LPCI started automatically injection on high DW pressure or low RPV water level with time delay. (Notes (a) and (b)) (seconds)	68	68	68	68	68	68
Time to turn off one CS pump. The other two CS pumps continue operation. (Notes (a) and (b)) (seconds)	600	600	600	600	600	600
Time to turn off one LPCI (RHR) pump. (seconds)	600	600	600	600	600	600
Time when the other two LPCI (RHR) pumps are turned off for preparing containment cooling. (Notes (a) and (b)) (seconds)	600	600	600	600	600	600
Time when Wetwell Spray is initiated with two RHR pumps. (Note (c)) (seconds)	1200	1200	1200	1200	1200	1200
Time when Drywell Spray is initiated with two RHR pumps. (Note (c)) (seconds)	~1700	1200	1200	1200	1200	1200
Time when the operators initiate RPV depressurization at 100ºF /hour when suppression pool temperature reaches 120ºF. (seconds)	~1922	~1884	~1149	~615	Note (h)	Note (h)
Time when RPV depressurization is stopped with RPV pressure reaches 50 psig. At this time RPV depressurization is terminated. The operator maintains the RPV pressure at 50 psig after this time. (seconds)	~11400	~10490	~8250	~4735	Note (h)	Note (h)
Time when analyses are terminated.	24 hours	24 hours	24 hours	24 hours and 100 days	24 hours	24 hours

Note: Notes (a) through (g) of Table SCVB-RAI 7-1 below specifically address those same items listed in the RAI.

(a) Low pressure ECCS pumps are operating at bypass flow (minimum pump flow) return to the SP if those pumps have been started due to high DW pressure or low RPV water level logic and if they are not in RPV injection mode.

For the first 10 minutes:

The low pressure ECCS pumps (RHR and CS) are assumed to start automatically at high DW pressure. This is conservative because an early pump start maximizes the pump heat addition to the SP. Because RPV pressure is higher than the low pressure permissive for RPV injection for all breaks except for the breaks of 0.5 ft^2 and 1.0 ft^2 during the first 10 minutes, the low pressure ECCS pumps operate in the minimum flow mode, and no injection to the RPV is made. For the largest breaks (0.50 ft^2 and 1.0 ft^2), injection to the RPV by low pressure ECCS occurs for a very short period of time (on the order of 10 seconds). The RHR and CS pumps operate on minimum flow return to the SP for the rest of the time.

For the time after 10 minutes:

After 10 minutes, two CS pumps are used to maintain the RPV water level. CS pumps are in either RPV injection mode or minimum flow mode. The CS pumps operate continuously in minimum flow mode until the RPV pressure is below the low pressure permissive after which the CS pumps are cycled between RPV injection mode and minimum flow mode to maintain RPV water level. When the RPV water level reaches high water level, CS pumps are then switched into minimum flow mode until the RPV water level reaches low RPV water level. Those two modes are alternating each other until the end of the containment analysis run. Note that the CS pumps are in minimum flow mode for most of the event. CS pumps inject water into the RPV for only a few hundred seconds during every RPV inventory makeup cycle, and then are switched to the minimum flow mode by operator action.

The low pressure coolant injection (LPCI) mode of RHR is secured by the operator at 10 minutes. Two RHR pumps are used as containment (drywell and wetwell) sprays when conditions are satisfied (see Note c below).

(b) See discussion also in Note (a). In the analysis, HPCI does not supply water simultaneously with RHR and CS systems for any period of time because HPCI is assumed to be unavailable.

The following provides the times when CS first injects fluid into the RPV.

0.01ft^2	~6640 seconds
0.05ft^2	~5800 seconds
0.10ft^2	~3580 seconds
0.25ft^2	~990 seconds
0.50 ft^2	~330 seconds
1.00 ft^2	~140 seconds

In the analysis, LPCI supplies water simultaneously with CS for 0.50 and 1.0 ft^2 only once for about 10 seconds. In the analyses, the CS pumps and LPCI pumps are modeled as a single ECCS system for the first 10 minutes due to code input constraints. This modelling is why they simultaneously inject water in the RPV. The pressure permissive for RPV injection used for this simulated combined LPCI and CS ECCS system in the model is the LPCI permissive pressure, which is higher than that for CS pump and results in slightly earlier injection time for CS than would be predicted based on the CS permissive pressure. This modeling approach has negligible effect on the containment response. The following provides the times when LPCI first injects fluid into the RPV.

0.01ft^2	Never
0.05ft^2	Never
0.10ft^2	Never
0.25ft^2	Never
0.50 ft^2	~330 seconds
1.00 ft^2	~140 seconds

(c) Wetwell spray is initiated when the following conditions are satisfied.

I. DW pressure ≥ 17.1 psia and is in the safe area of BFN Primary Containment Control EOI-2 Curve 6

II. A 60 second delay is added from the times determined from Item I. However, for the analysis, wetwell spray is initiated no earlier than 1200 seconds into the event.

Wetwell spray never stops after it is initiated.

Drywell spray is initiated when the following conditions are satisfied.

I. DW temperature ≥ 280ºF

II. Suppression pool level < 19 ft and DW temperature within the safe area of EOI-2 curve 5

III. 60 second delay is added from the time determined from Items I and II. However, for the analysis DW spray is initiated no earlier than 1200 seconds into the event.

Drywell spray never stops after it is initiated.

(d) For breaks greater than 0.01 ft^2, the conditions for initiating drywell and wetwell sprays (see Note © above) are satisfied before 10 minutes. However, the analysis assumed that there is no containment cooling before 10 minutes. In addition, another 10 minute delay of containment sprays is assumed to consider the possible LPCI High DW Pressure/Low RPV Pressure LOCA signal interruption. Therefore, the drywell and wetwell containment sprays are initiated at 20 minutes from the initiation of the vents. Please refer to the response to SCVB-RAI 5 on how the delaying of drywell and wetwell spray initiation by up to 20 minutes will address the concern related to ECCS interruption caused by a subsequent LOCA signal (activated on high DW pressure concurrent with low RPV pressure).

(e) Please see Note (d) above and the response to SCVB-RAI 5.

(f) The sequence of events assumed in the analyses are consistent with the BFN symptom-based Emergency Operating Instructions (EOIs) for all break sizes. There are, however, assumptions made in the containment response analyses that delay certain operator actions in order to conservatively maximize the containment response. For example, as discussed in the TVA response to SCVB RAI-5, operator action to initiate containment spray assumes a 20-minute delay; whereas the BFN EOIs have no such time constraint.

(g) The BFN EOIs are symptom based and are designed to allow the operator to mitigate the consequences of accidents irrespective of the LOCA break size or location. The EOIs are the same for any LOCA break size, however, the RPV and containment response would be different for different break sizes. Consequently, the timing of operator actions or the operator actions, in accordance with the EOIs, necessary to mitigate the consequences of the accident may be different based upon the containment response to the different break size. As stated in the response to SCVB RAI-5 and the response to part (f) of this RAI response, the operator action to initiate containment spray is consistent with the BFN EOIs for all break sizes. The slow depressurization rate of the RPV for the smallest (0.01 ft^2) break provides the operator ample time to inhibit the generation of a LOCA signal due to high DW pressure coincident with low RPV pressure. The slow containment pressurization and containment heatup for the smallest (0.01 ft^2) break results in the containment reaching the BFN EOI entry conditions for initiating containment spray later in the accident. For the analyzed break sizes greater than 0.01 ft^2, the EOI entry conditions for initiating containment spray will occur prior to the time assumed in the containment response analyses for containment spray initiation. Therefore, the assumptions used in BFN containment analyses are both in accordance with the BFN EOIs and are conservative for maximizing the containment response.

(h) For larger break sizes with break size sufficiently large to produce a depressurization rate greater than 100ºF/hour, manual operator action to depressurize the RPV with Safety Relief Valves is not required.

Table SCVB-RAI 7-2
Event Sequences for Browns Ferry SSLB with HPCI Available

Items	0.01ft^2	0.25 ft^2 (d)
Steam line break occurs. Loss of Offsite Power. Reactor scrams. (seconds)	0	0
MSIV starts to close. (seconds)	0.5	0.5
MSIV is fully closed. (seconds)	3.5	3.5
The time when HPCI is injecting flow into RPV. HPCI started automatically on high DW pressure or RPV low water level with a time delay. (seconds)	50	50
Three CS started automatically injection on high DW pressure or low RPV water level with time delay. (Notes (a) and (b)) (seconds)	68	68
Three LPCI started automatically injection on high DW pressure or low RPV water level with time delay. (Notes (a) and (b)) (seconds)	68	68
Time to turn off one CS pump. The other two CS pumps continue operation. (Notes (a) and (b)) (seconds)	600	600
Time to turn off one LPCI (RHR) pump. (seconds)	600	600
Time when the other two LPCI (RHR) pumps are turned off for preparing containment cooling. (Notes (a) and (b)) (seconds)	600	600
Time when Wetwell Spray is initiated with two RHR pumps. (Note (c)) (seconds)	1200	1200
Time when Drywell Spray is initiated with two RHR pumps. (Note (c)) (seconds)	~1705	1200
Time when the operators initiate RPV depressurization at 100ºF /hour when suppression pool temperature reaches 120ºF. (seconds)	~2007	~759
Time when RPV depressurization is stopped with RPV pressure reaches 50 psig. At this time RPV depressurization is terminated. The operator maintains the RPV pressure at 50 psig after this time. (seconds)	~11565	~4860
Time when HPCI isolates due to low RPV pressure. (55 psig)	~11246	~8554 (h)
Time when analyses are terminated.	24 hours	24 hours

Note: Notes (a) through (g) of Table SCVB-RAI 7-2 below specifically address those same items listed in the RAI.

(a) Low pressure ECCS pumps are operating at bypass flow (minimum pump flow) return to the SP if those pumps have been started due to high DW pressure or low RPV water level logic and if they are not in RPV injection mode.

For the first 10 minutes:

The low pressure ECCS pumps (RHR and CS) are assumed to start automatically at high DW pressure. This is conservative because an early pump start maximizes the pump heat addition to the SP. Because RPV pressure is higher than the low pressure permissive for RPV injection for the breaks during the first 10 minutes, the low pressure ECCS pumps operate in minimum flow mode, and no injection to the RPV occurs.

For time after 10 minutes:

After 10 minutes, two CS pumps are used to maintain RPV water level. CS pumps are in either RPV injection mode or minimum flow mode. The CS pumps operate continuously in minimum flow mode until the RPV pressure is below the RPV low pressure permissive after which the CS pumps are cycled between RPV injection mode and minimum flow mode to maintain RPV water level. When the RPV water level reaches high water level, the CS pumps are then switched into minimum flow mode until the RPV water level reaches low RPV water level. Those two modes are alternating each other until the end of the containment analysis run. Note that the CS pumps are in minimum flow mode for most of the event. CS pumps inject water into the RPV for only a few hundreds seconds during every RPV inventory makeup cycle, and then are switched to minimum flow mode by operator action.

The low pressure coolant injection (LPCI) mode of RHR is secured by the operator at 10 minutes. Two RHR pumps are used for containment (drywell and wetwell) spray when containment conditions are satisfied (see Note c below).

(b) See discussion also in Note (a).

The following provides the times when CS first injects fluid into the RPV.

$0.01ft^2$	~4640 seconds
$0.25ft^2$	~670 seconds

The RHR pumps never inject water into the RPV for those two breaks since the pumps are switched to containment spray mode at 10 minutes, before the RPV depressurizes to the low pressure permissive for RPV injection.

For both breaks, HPCI first injects fluid into the RPV at 50 seconds. For a break of 0.25 ft^2, HPCI does not supply water simultaneously with CS for any period of time. For a break of 0.01 ft^2, HPCI does supply water simultaneously with CS for only one period of time (HPCI operation period is from about 4260 seconds to 4670 seconds, and CS pumps also start to inject into the RPV at ~4640 seconds, lasting only ~10 seconds.

(c) Wetwell spray is initiated when the following conditions are satisfied.

I. DW pressure ≥ 17.1 psia and is in the safe area of BFN Primary Containment Control EOI-2 Curve 6

II. A 60 second delay is added from the times determined from Item I. However, for the analysis, wetwell spray is initiated no earlier than 1200 seconds into the event.

Wetwell spray never stops after it is initiated.

Drywell spray is initiated when the following conditions are satisfied.

I. DW temperature ≥ 280ºF

II. Suppression pool level < 19 ft and DW temperature within the safe area of EOI-2 curve 5

III. 60 second delay is added from the time determined from Items I and II. However, for the analysis drywell spray is initiated no earlier than 1200 seconds into the event.

DW spray never stops after it is initiated.

(d) For breaks greater than 0.01 ft^2, the conditions for initiating drywell and wetwell sprays (see Note (c) above) are satisfied before 10 minutes. However, the analysis assumed that there is no containment cooling before 10 minutes. In addition, another 10 minute delay of containment sprays is assumed to consider the possible LPCI High DW Pressure/Low RPV Pressure LOCA signal interruption. Therefore the drywell and wetwell containment sprays are initiated at 20 minutes from the initiation of the vents. Please refer to the response to SCVB-RAI 5 on how the delaying of drywell and wetwell spray initiation by up to 20 minutes will address the concern related to ECCS interruption caused by a subsequent LOCA signal (activated on high DW pressure concurrent with low RPV pressure).

(e) Please see Note (d) above and the response to SCVB-RAI 5.

(f) The sequence of events assumed in the analyses are consistent with the BFN symptom-based EOIs for all break sizes. There are, however, assumptions made in the containment response analyses that delay certain operator actions in order to conservatively maximize the containment response. For example, as discussed in the TVA response to SCVB-RAI 5, operator action to initiate containment spray assumes a 20-minute delay; whereas the BFN EOIs have no such time constraint.

(g) The BFN EOIs are symptom based and are designed to allow the operator to mitigate the consequences of accidents irrespective of the LOCA break size or location. The EOIs are the same for any LOCA break size, however, the RPV and containment response would be different for different break sizes. Consequently, the timing of operator actions or the operator actions, in accordance with the EOIs, necessary to mitigate the consequences of the accident may be different based upon the containment response to the different break size. As stated in the response to SCVB RAI-5 and the response to part (f) of this RAI response, the operator action to initiate containment spray is consistent with the BFN EOIs for all break sizes. The slow depressurization rate of the RPV for the smallest (0.01 ft^2) break provides the operator ample time to inhibit the generation of a LOCA signal due to high DW pressure coincident with low RPV pressure. The slow containment pressurization and containment heatup for the smallest (0.01 ft^2) break results in the containment reaching the BFN EOI entry conditions for initiating containment spray later in the accident. For the analyzed break sizes greater than 0.01 ft^2, the EOI entry conditions for initiating containment spray will occur prior to the time assumed in the containment response analyses for containment spray initiation. Therefore, the assumptions used in BFN containment analyses are both in accordance with the BFN EOIs and are conservative for maximizing the containment response.

(h) The RPV pressure is slightly increased after initial depressurization so that HPCI is operated until later time. The operation of HPCI for a long time does not impact the results for this case.

Reference

1. GE Hitachi Nuclear Energy, “Safety Analysis Report for Browns Ferry Nuclear Plant Units 1, 2 and 3 Extended Power Uprate,” NEDC-33860P, September 2015.

SCVB-RAI 9

Section 2.6.5.2 of PUSAR under heading "ECCS NPSH Summary" states:

> *The ECCS strainer design debris load, which was used as an input to the strainer design, is documented Reference 38 [NEDC-32721-P-A]. The quantity and characterization of the strainer debris loading is based on the methodology in Reference 102.*

GE-Hitachi Nuclear Energy (GEH) letter (MFN-08-286) dated March 24, 2008 "Notification of Inaccurate Correlation in GE Hitachi Nuclear Energy (GEH) Licensing Topical Report NEDC-32721P-A, 'Application Methodology for the General Electric Stacked Disk ECCS Suction Strainer'" (ADAMS Accession Number ML080850242), reported inaccurate correlation for the strainer debris-bed head loss in the NEDC-32721-P-A.

Describe the methodology, correlation, and their basis for the strainer debris-bed head loss calculation for available NPSH calculation during accident and special events.

TVA Response:

BFN Units 1, 2, and 3 are the three plants cited in GEH letter MFN-08-286 as not affected by the strainer head loss correlation issue as their strainer debris-bed head loss is caused primarily by reflective metal insulation rather than fibrous and particulate debris. Therefore, the ECCS suction strainer design debris load and the quantity and characterization of strainer debris loading is as stated in PUSAR Section 2.6.5.2.

SCVB-RAI 10

Section 2.6.5.2 of PUSAR, second paragraph under heading "Loss of RHR SDC [Shutdown Cooling] ECCS NPSH" states:

> *The assumption of HPCI operation is conservative for the determination of peak suppression pool temperature. However, HPCI pump suction from the suppression pool is limited to suppression pool temperatures below 140°F, the maximum allowed temperature at Browns Ferry for HPCI operation.*

In the suppression pool temperature response analysis for the loss of RHR SDC event, the HPCI suction source is assumed to be a suppression pool that its temperature varies from 95°F to 140°F during the event till the HPCI is isolated at its RPV isolation pressure or the pool temperature of 140°F. The alternate suction source for the HPCI pump suction is condensate storage tank (CST) whose temperature is fixed at 130°F (PUSAR, Table 2.6-2b). It does not appear that the assumption of HPCI operation is conservative for the determination of peak suppression pool temperature. Justify results of suppression pool temperature response for the case with HPCI suction from suppression pool and the case with HPCI suction CST. Note that the same comment applies to suppression pool temperature response analysis for the stuck open relief valve (SORV) with RPV isolation event in which HPCI suction source is assumed to be suppression pool instead of CST, which is at 130°F.

TVA Response:

TVA agrees that performing the Loss of Shutdown Cooling (SDC) and Stuck Open Relief Valve (SORV) containment response analyses with the assumption of High Pressure Coolant Injection (HPCI) availability during the entire event with suction from either the suppression pool (SP) or the condensate storage tank (CST) would result in a higher peak SP temperature. If HPCI is assumed available for the entire event, HPCI would provide reactor inventory makeup until reactor pressure decreases below the HPCI isolation pressure, after which Core Spray (CS) provides reactor inventory makeup. If HPCI is not available, the Automatic Depressurization System (ADS) would be used to rapidly reduce reactor pressure to allow CS to provide vessel makeup. Such use of ADS results in a faster heatup of the SP. With reactor pressure at the time of peak SP temperature the same, the total (integrated) sensible heat addition to the SP remains the same, but the total (integrated) decay heat to the pool at the time of peak suppression pool temperature is greater for the slower (HPCI available for the entire event) SP heatup. In addition, the heat removed from the SP is lower for the slower SP heatup. Thus, a slower SP heatup would result in a higher peak SP temperature.

TVA emphasizes that operation of HPCI with suction from the SP with SP temperatures greater than 140°F is not in accordance with how HPCI would be operated during these events. Further, the assumption of HPCI operation with suction from the CST during the entire event until it isolates on low steam pressure is not in accordance with the current licensing basis containment response analyses for the loss of SDC and SORV events.

The effect on the peak SP temperature is less than 2°F for the loss of SDC and SORV events if the containment response analyses are performed with the assumption of HPCI running for the entire event (either with suction from the SP or the CST) until HPCI isolates on low steam pressure. This 2°F effect is justified by the sensitivity studies performed for the small steam break events, EPU LAR Attachment 6, Power Uprate Safety Analysis Report (PUSAR), Section 2.6.5 under the topic Suppression Pool Temperature Response - Small Break LOCA, where HPCI was both assumed to operate until it isolates on low steam pressure and where HPCI was assumed as unavailable. These sensitivity studies showed a higher peak SP temperature of 1.2°F for the case where HPCI operation was assumed (peak SP temperature of 182.7°F) versus the case where HPCI was assumed as unavailable (peak SP temperature of 181.5°F).

If HPCI operation from the CST was assumed, the effect on peak SP temperature would be similar to that for continuous HPCI operation with suction from the SP. Early in the event, the higher CST temperature (130°F CST temperature versus the initial SP temperature of 95°F) would result in a small increase in reactor steam generation from sensible and decay heat due to the higher CST enthalpy. This effect lessens as the SP begins to heat up. Later in the event after SP temperature reaches 130°F, the lower enthalpy (cooler) of the CST water injected to the RPV would result in less steam generation from sensible and decay heat and ultimately less heat addition to the SP. The net effect on SP temperature response is similar to the response from continuous HPCI operation with suction from the SP. In addition, CST inventory injection to the RPV would ultimately deposit into the SP, which would result in a higher SP level and mitigate the effect of higher SP temperature on ECCS pump net positive suction head (NPSH). The assumption of HPCI operation from the CST would also result in an increase in the SP level response that would mitigate the loss of RHR pump and CS pump NPSH margin due to the 2°F SP temperature increase for the loss of SDC and SORV events. The loss of SDC and SORV events remain non-limiting with respect to ECCS NPSH margin for the RHR and CS pumps.

The table below summarizes the impact of HPCI operation during the loss of SDC and SORV events:

Event	Peak SP Temperature (°F) Note 1	Peak SP Temperature (°F) Note 2	RHR NPSH Margin (feet) Note 3	RHR NPSH Margin (feet) Note 4	CS NPSH Margin (feet) Note 3	CS NPSH Margin (feet) Note 4
Loss of SDC	178.3	180.3	12.4	11.7	10.4	9.6
SORV	161.8	163.8	17.3	16.7	15.2	14.7

Notes

1. Peak SP temperature reported in PUSAR Table 2.6-4.
2. Peak SP temperature with addition of 2°F impact due to HPCI operation.
3. NPSH margin from PUSAR Table 2.6-4.
4. NPSH margin considering 2°F higher SP temperature. Results shown for HPCI suction from the SP. NPSH margin with HPCI suction from the CST would be larger.

ENCLOSURE

SCVB-RAI 11

Section 2.6.5.2 of PUSAR, last paragraph under heading "Loss of RHR SDC ECCS NPSH" states that the suppression pool temperature response analysis for the loss of RHR SDC event is also applicable for a small liquid break LOCA. Provide a description of the suppression pool temperature response analysis of the small liquid line break LOCA performed, including the liquid line and its size inside the drywell that would be most limiting. Explain why the suppression pool temperature response for the small liquid break LOCA, the RHR and CS NPSHa and NPSH margins would be bounded by the same parameters for the small steam break LOCA reported in Table 2.6-4 of PUSAR.

TVA Response:

TVA clarifies that the statement contained in the PUSAR Section 2.6.5.2 under the heading "Loss of RHR SDC ECCS NPSH" is "The suppression pool temperature response analysis for the loss of RHR SDC event is also applicable for a small liquid break LOCA wherein the suppression pool cooling mode is used in lieu of the containment spray cooling mode."

The SP temperature response analysis for small liquid line breaks is similar to that of the small steam line break analysis stated in PUSAR Section 2.6.5.1 under the heading "Suppression Pool Temperature Response - Small Steam Line Break LOCA." Initial reactor conditions are consistent with operation at 102% of EPU rated thermal power, and the same decay heat, relaxation and metal-water reaction energies are assumed as is used for the large DBA-LOCA analysis. Consistent with the large DBA-LOCA assumptions, a loss of off-site power (LOOP) is assumed. A worst-case single failure is also assumed for this analysis to minimize the available quantity of containment cooling. HPCI is available with suction only from the SP. HPCI is assumed to start automatically on high drywell pressure or low RPV level. For BFN, HPCI is qualified only for water temperatures up to 140°F. Therefore, when HPCI suction temperature reaches 140°F, HPCI is secured and the reactor is depressurized to allow CS to provide reactor inventory makeup. The effect on SP temperature of allowing HPCI operation from the SP during the entire event is discussed in the response to SCVB-RAI 10.

Automatic starting of ECCS pumps would occur in accordance with their start logic and timing for electrical loading. Operators initiate depressurization of the RPV at 100°F/hour when SP temperature reaches 120°F. At no sooner than 10 minutes after the start of the accident, operators would stop all but two RHR pumps and two CS pumps. At no sooner than 10 minutes after the start of the accident, operators would either re-align or start two RHR pumps in suppression pool cooling (SPC) mode (two RHR pumps at 6,500 gpm each with two RHR heat exchangers with a K-factor of 265 BTU/sec-°F per heat exchanger). To address concerns related to ECCS interruption caused by subsequent LOCA signal activated on high DW pressure concurrent with low RPV pressure, it is assumed that containment cooling is interrupted for 10 minutes prior to the time of the peak SP temperature. RPV depressurization would be terminated when RPV pressure reaches 50 psig. Operators would maintain RPV pressure between 50 psig and 100 psig until shutdown cooling can be restored.

A spectrum (1.0 ft^2, 0.5 ft^2, 0.10 ft^2, 0.25 ft^2, 0.05 ft^2, 0.01 ft^2) of small liquid line breaks are assumed, consistent with the small steam line breaks. The difference between liquid line breaks and steam line breaks is that the liquid line breaks are assumed as un-isolable breaks that occur in the reactor coolant pressure boundary liquid volume versus the breaks being un-isolable breaks that occur in the reactor coolant pressure boundary steam volume for the small steam breaks. Because the break flow is an isenthalpic process, the steam line breaks result in superheated steam discharged to the drywell atmosphere, while the liquid line breaks result in two-phase break flow into the drywell atmosphere. Therefore, the drywell temperature response for the small liquid line breaks is less severe than for the small steam line breaks. The BFN EOI entry point for drywell spray (280°F) is either not reached for the liquid line breaks or the duration of drywell spray operation for the liquid line breaks is much less for the liquid line breaks than for the steam line breaks. Because the non-operation or limited operation of drywell sprays for the liquid line breaks allows a greater holdup of the sensible heat in the drywell, less heat is discharged to the SP for the liquid line breaks and the peak SP temperature is consequently less for a given liquid line break size than for the same size steam line break.

For the SP temperature response, the limiting liquid line break size of the break spectrum is the smallest break size (0.01 ft^2) consistent with the results of the small steam line break. The smaller break sizes results in slower SP heatup. With reactor pressure at the time of peak pool temperature the same, the total (integrated) sensible heat addition to the SP remains the same, but the total (integrated) decay heat to the SP at the time of peak SP temperature is greater for the slow pool heatup. In addition, the heat removed from the SP is less for the slow pool heatup. Thus, a slower pool heatup will result in a higher peak SP temperature.

SCVB-RAI 12

Section 2.6.5.2 of PUSAR, third paragraph under heading "Small Break LOCA ECCS NPSH" states:

> *As stated in Section 2.6.5.1, the suppression pool temperature response was evaluated for cases where HPCI was assumed not available and where HPCI was conservatively assumed available with suction from the suppression pool for the entire duration of the small break event. Because HPCI is only qualified for a suction temperature of up to 140°F, the assumption of HPCI available with suction from the suppression pool during the entire event is not realistic.*

Section 2.6.5.1 of PUSAR, second paragraph under heading "Suppression Pool Temperature Response –Small Steam [Steamline] Break LOCA" states:

> *If HPCI is conservatively assumed available, HPCI will provide reactor inventory makeup until the reactor pressure decreases below the HPCI isolation pressure, after which low-pressure ECCS provides reactor inventory makeup.*

During any SSLB LOCA (not necessarily the most limiting for peak suppression pool temperature), in case the suppression pool temperature exceeds 140°F before the HPCI isolation pressure is reached, how is the HPCI operation prevented at higher pool temperatures?

TVA Response:

The BFN EOIs contain caution statements stating that operating the HPCI turbine with suction temperature above 140°F may result in equipment damage. The BFN operators are trained to not operate HPCI with suction temperature above 140°F unless there are no other means for ensuring adequate core cooling during an event or accident. HPCI operation at higher suppression pool temperatures would be prevented by the operator tripping the HPCI turbine and locking out the HPCI auxiliary oil pump.

SCVB-RAI 13

Section 2.6.5.2 of PUSAR, last sentence in second paragraph under heading "Fire Event ECCS NPSH" mentions about the analysis performed for a sensitivity case to show increased NPSH margin during the fire event. The third paragraph states:

> *The sensitivity case involved an analysis where a postulated 1,000 hp [horsepower] electric-driven Emergency High Pressure Makeup Pump (EHPMP) could be used as defense-in-depth to inject water from the CST through the FW piping and into the RPV while the RHR pump was operating in ASDC [Alternate Shutdown Cooling] mode. This effectively provides a means of pumping CST inventory through the RPV and into the torus to increase the suppression pool mass, providing more mass to accept the heat input from the RPV while at the same time increasing the suppression pool level which would increase the RHR pump NPSHa.*

The statement does not confirm that the equipment is already installed or will be installed before EPU implementation for water addition to the suppression pool. Confirm that all equipment, piping, and connections on which the sensitivity case analysis is based is currently, or will be, installed in all BFN Units prior to EPU implementation; and state the plant system the equipment belongs to, or would belong to.

TVA Response:

In the BFN EPU LAR, under the section entitled, "Fire Event ECCS NPSH," the limiting containment response case is detailed wherein a single RHR pump would be started in the alternate shutdown cooling (ASDC) mode. This case demonstrated positive NPSH margin and thus, containment accident pressure (CAP) credit was not required. However, the small margin prompted a further sensitivity case to show increased margin. This sensitivity case involved describing the benefits gained by a postulated 1,000 horsepower electric-driven emergency high pressure makeup pump (EHPMP) that could be used to increase the RHR pump NPSH and thus add margin. Since the EPU LAR was submitted, NPSH analysis has continued that demonstrates additional margin. The NPSH margin gained by the benefit of the postulated EHPMPs is no longer needed and the sensitivity runs, involving these pumps, will be removed from the EPU LAR in EPU LAR Supplement 24. EPU LAR Supplement 24 is scheduled to be submitted by July 25, 2016. The installation of the EHPMPs is no longer required to be linked to EPU implementation.

SCVB-RAI 15

Refer to Section 2.6.2 of PUSAR and Section 12.2.2.6 of UFSAR,

Section 12.2.2.6 of UFSAR, fourteenth paragraph describes the effect of jet reaction force on the SSW and its supports as follows:

> *The jet load used in the design is the worst condition of either a clean break of the 26-inch main steam reactor pressure vessel penetration resulting in a jet reaction force of 595 kips, or a clean break of the 28-inch recirculating loop outlet penetration resulting in a jet reaction force of 658 kips.*

a. What is meant by a clean break as compared to a double-ended break?

b. What is the load carrying capability of the SSW and its supports?

Section 2.6.2 of PUSAR does not address the jet reaction forces from the 26-inch main steam reactor pressure vessel penetration and the 28-inch recirculating loop outlet penetration on the SSW and its supports at EPU condition. Provide a description of the most limiting analysis and results of the jet reaction forces from a clean break and double-ended break of the same 26-inch main steam RPV penetration, the clean and double-ended break of the 28-inch recirculation loop outlet penetration, and the breaks of FW line under EPU conditions. Justify that the conditions (such as fluid density, jet velocity, etc,) assumed in the analysis are most limiting. What is the capability of the SSW and its supports for carrying these loads?

TVA Response:

Jet reaction forces on the sacrificial shield wall (SSW) and its supports are a product of the pipe area and the pipe pressure. Pipe areas remain unchanged from the values used in the original design analysis and the original evaluation used conservative pressures to calculate the jet force. The 26-inch main steam break utilized a bounding steam pressure of 1325 psig and the 28-inch recirculating loop break utilized a bounding reactor recirculation system pressure of 1250 psig. Both of these pressures bound operating pressures at EPU conditions. Therefore, jet reaction forces on the SSW and its supports at EPU conditions are bounded by the original design.

a. Both “clean break” and “double-ended break” refer to an instantaneous double-ended guillotine break of the subject piping.

b. As discussed with the NRC reviewer during a clarification call on April 8, 2016, TVA confirms that the SSW and its supports remain capable of carrying the jet loads, as the original design bounds conditions at EPU.

SCVB-RAI 16

Section 2.6.1.5 of PUSAR states:

> *The Browns Ferry analysis of record at CLTP shows that the recirculation line break DBALOCA event causes boiling in the drywell cooling coils sooner than for steam line breaks at CLTP conditions. A comparison of the drywell temperature profiles during a DBA-LOCA for CLTP and EPU conditions shows a minor difference in temperature (less than 2°F) and lasting only seconds. Based on the minor differences in the drywell temperature profiles and the margin between the RBCCW pump start (40 seconds) and calculated time to boil (61 seconds), it is concluded that voiding will not occur under EPU conditions prior to the restart of a RBCCW [reactor building closed cooling water] pump.*

Table 2.6-1 of PUSAR shows peak drywell temperature of 297°F for Units 2 and 3, and 295.2 °F for Unit 1 in the current licensing basis analysis. Table 2.6-1 shows 336.9°F EPU long-term drywell gas temperature for the SSLB. In the current response to Generic Letter (GL) 96-06, the boiling time in the drywell cooling coils of 61 seconds should be based on the short-term drywell gas temperatures.

In the current response to GL 96-06, what are the drywell gas and the RBCCW temperatures used in the analysis to determine the boiling time of 61 seconds in the drywell cooling coils? State the basis for these temperatures and confirm that the both are limiting for the boiling time of 61 seconds in the RBCCW piping and the drywell cooler cooling coils. Provide the same temperature under the EPU conditions with justification that these are most limiting for the boiling time determination in the drywell cooling coils.

TVA Response:

1) The current licensing basis peak drywell temperature (297°F for Units 2 and 3, and 295.2°F for Unit 1) is based on the DBA-LOCA. The PUSAR Table 2.6-1 EPU peak drywell temperature of 336.9°F is based on a small steam line break. Note 8 of PUSAR Table 2.6-1, applied to the Current Licensed Thermal Power (CLTP) peak drywell temperature results, states, “This value is for a recirculation line liquid break. The Unit 2 and Unit 3 peak drywell airspace temperature for a steam line break is 336ºF (Reference 104). The Unit 1 peak drywell airspace temperature for a steam line break is 335.4ºF (Reference 105).” The recirculation line liquid break is the recirculation suction line DBA-LOCA.

A comparison, based on the different LOCA events of CLTP versus EPU peak drywell temperature as follows.

Parameter	CLTP - DBA LOCA	EPU -with EPU Model - DBA-LOCA	CLTP - Steam Line Break LOCA	EPU - with EPU Model - Steam Line Break LOCA
Peak Drywell Temperature (°F)	297 - U2, U3 295.2 - U1	297.5 (D) 295.8 (B) 295.2 (R)	336 - U2, U3 335.4 - U1	336.9

The initial drywell temperature conditions for the EPU DBA-LOCA (D), (B), and (R) results are stated in Note 7 below PUSAR Table 2.6-1. The CLTP DBA-LOCA peak drywell temperature values were determined by analyses that assumed an initial drywell temperature of 150°F. The above table shows that the peak drywell temperature at EPU increases by a maximum of 2.3°F (297.5°F - 295.2°F) for the DBA-LOCA and 1.5°F (336.9°F - 335.4°F) for the steam line break LOCA, which is not significant.

Both the current licensing basis and the proposed EPU basis for the time to boil are based on the drywell response profile for the DBA-LOCA. The current licensing basis analysis for determining the RBCCW time to boil for all three BFN units was based on the CLTP drywell temperature response profile associated with the Unit 2/Unit 3 peak drywell temperature of 297°F.

2) In both the current licensing basis and the proposed EPU GL 96-06 analysis, the RBCCW initial temperature is set at 150°F. This RBCCW temperature value is conservative for the following reasons: 1) the 150°F value is greater than the maximum abnormal temperature of 140°F for the RBCCW system; 2) the maximum normal operation drywell airspace temperature allowed by Technical Specifications is 150°F; therefore assuming RBCCW in thermal equilibrium to this maximum drywell temperature is reasonable; 3) the assumption of RBCCW temperature at 150°F also places this initial RBCCW liquid temperature closer to the boiling point.

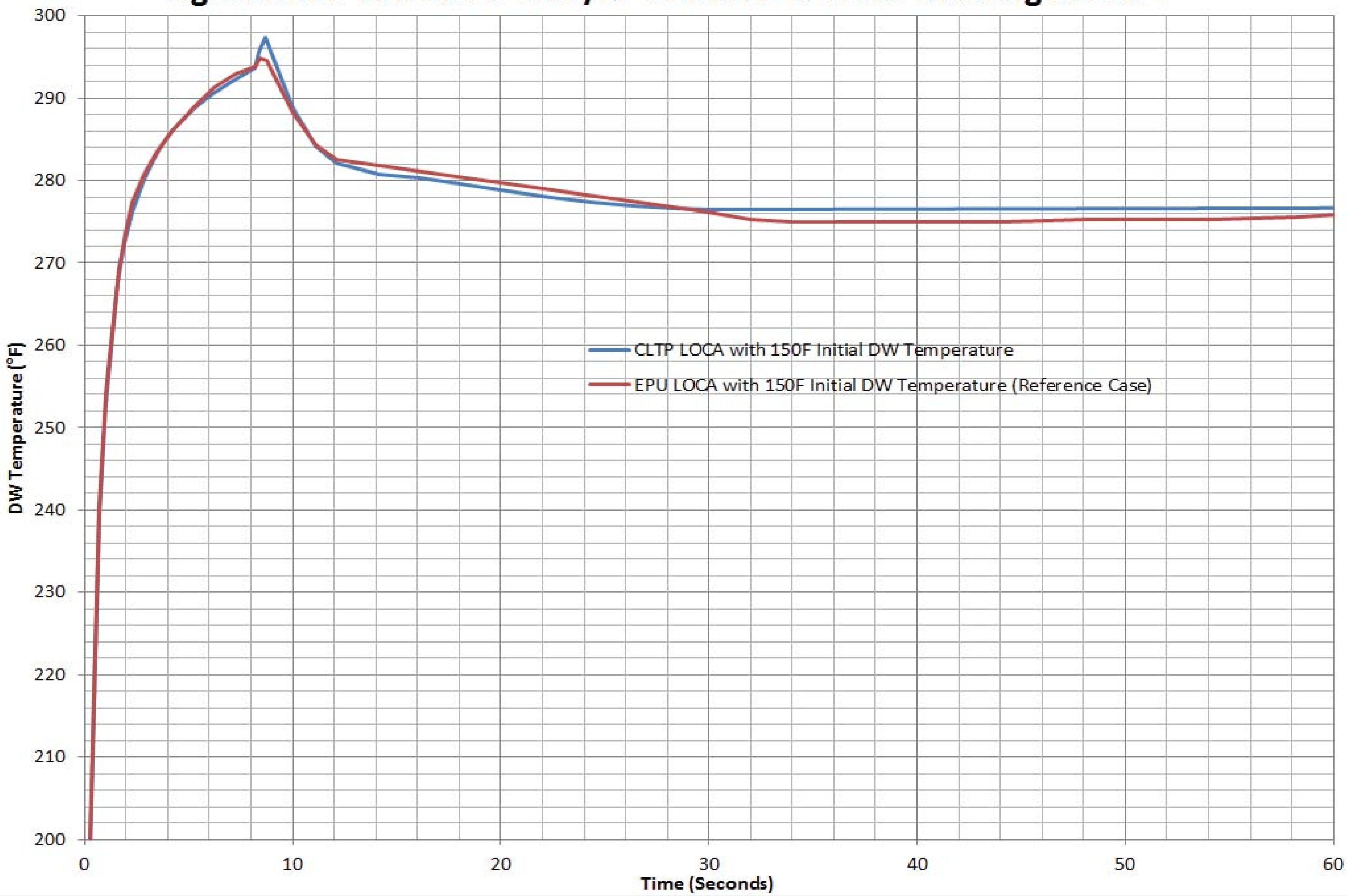
The EPU DBA LOCA drywell gas temperature profiles with initial drywell temperature of 130°F (Bounding case) and 150°F (Reference case) were examined for the EPU evaluation for the time to boil. While the EPU DBA-LOCA design (D) case results in a slightly higher peak drywell temperature, this temperature profile was not used because the initial conditions for this case were designed to maximize the containment pressure response and the initial drywell temperature (70°F) to produce this peak pressure response are artificially low. Analyses show that the DBA-LOCA event causes boiling in the drywell cooling coils sooner than the main steam line break (MSLB) at CLTP conditions. The drywell temperature response in the first 80 seconds of the EPU steam line break LOCA analysis is essentially unchanged from the Units 2 and 3 CLTP steam line break analysis that was used in the CLTP boiling analysis. The drywell temperature profile generated from a DBA-LOCA with an initial temperature of 130°F produces a slightly higher temperature than the profile with an initial temperature of 150°F (slightly higher by less than 2°F between 10 and 14 seconds). However, establishing a bounding initial drywell temperature of 130°F with an RBCCW temperature of 150°F is not physically possible. If the RBCCW initial temperature were assumed to be 130°F for the Bounding case, the slightly higher resulting drywell temperature for such a short time period would not shorten the 61 seconds to boil time period as the water now has an additional 20°F to be heated. Therefore, the initial drywell gas temperature of 150°F and the resulting DBA-LOCA drywell temperature profile was used in the GL 96-06 evaluation.

3) Figure SCVB-RAI 16-1 shows the drywell temperature profiles for a DBA-LOCA with an initial drywell temperature of 150°F for both CLTP and EPU conditions. In comparing the drywell temperature profiles, the discussion is separated into the following three time periods:

- The largest differences in temperatures are seen in the first two seconds following a LOCA. The extent of the temperature difference ranges from approximately 6°F at 0.02 seconds to approximately 1°F at two seconds. When coupled with the small time duration, this difference is expected to have little effect on the drywell cooling time to boiling.
- From two seconds to eight seconds, the temperature difference continues to decrease until EPU conditions are bounded by the temperature profile in the CLTP calculation. The small temperature difference, combined with the small time duration is expected to have an insignificant effect on the time to boiling.
- For the remainder of the time, the temperature profile associated with EPU conditions is either bounded by, or very close to, the temperature profile from the CLTP calculation.

Based on the minor differences in the drywell temperature profiles and the margin between the RBCCW pump start (40 seconds) and calculated time to boil (61 seconds), it is concluded that voiding would not occur under EPU conditions prior to the restart of the RBCCW pump.

Figure SCVB-RAI 16-1: CLTP/EPU LOCA DW TEMP Starting at 150°F



SCVB-RAI 17

Section 2.6.1.5 of PUSAR provides the current and proposed responses to GL 96-06 for the demineralized water system, drywell floor drain sump discharge, drywell equipment drain sump discharge, and reactor water sampling system. For these systems, provide the penetration numbers in the UFSAR Table 5.2-2 for the piping between which containment isolation valves are under consideration for GL 96-06.

TVA Response:

Note: The use of X in a valve designator denotes Units 1, 2, and 3.

1) The penetration for the Demineralized Water System is X-20 on all three units. (See Figure SCVB-RAI 17-1.)

   a) Unit 1 - The demineralized water penetration was cut and capped by a modification and some of the piping inside the drywell has been removed. The possibility for pressurization due to heat-up of trapped water in the piping no longer exists for this line on Unit 1.
   b) Units 2 and 3 - The demineralized water penetration has been cut and capped but this penetration is still used to supply demineralized water to the drywell during outages. The piping internal to the drywell still remains. The GL 96-06 piping under consideration is between the pipe cap located outside of containment and the system isolation valves located inside containment.

2) The penetrations for the Drywell Floor Drain (FD) Sump and Equipment Drain (ED) Sump are X-18 and X-19 on all three units. (See Figures SCVB-RAI 17-2 and 3.)

   The containment isolation valves associated with these systems are as follows:

X-FCV-77-15A	ED	Inboard, Outside Containment
X-FCV-77-15B	ED	Outboard, Outside Containment
X-FCV-77-2A	FD	Inboard, Outside Containment
X-FCV-77-2B	FD	Outboard, Outside Containment

   The inboard and outboard isolation valves for primary containment are both located outside the drywell for the drywell equipment drain sump discharge piping and the drywell floor drain sump discharge piping. Therefore, the trapped water between the isolation valves is not subject to thermal over-pressurization during LOCA conditions. The GL 96-06 piping under consideration is between the inboard isolation valves located outside containment and the sump discharge check valves located inside containment.

3) The penetration for the Reactor Water Sampling System is X-41 on all three units. (See Figure SCVB-RAI 17-4.)

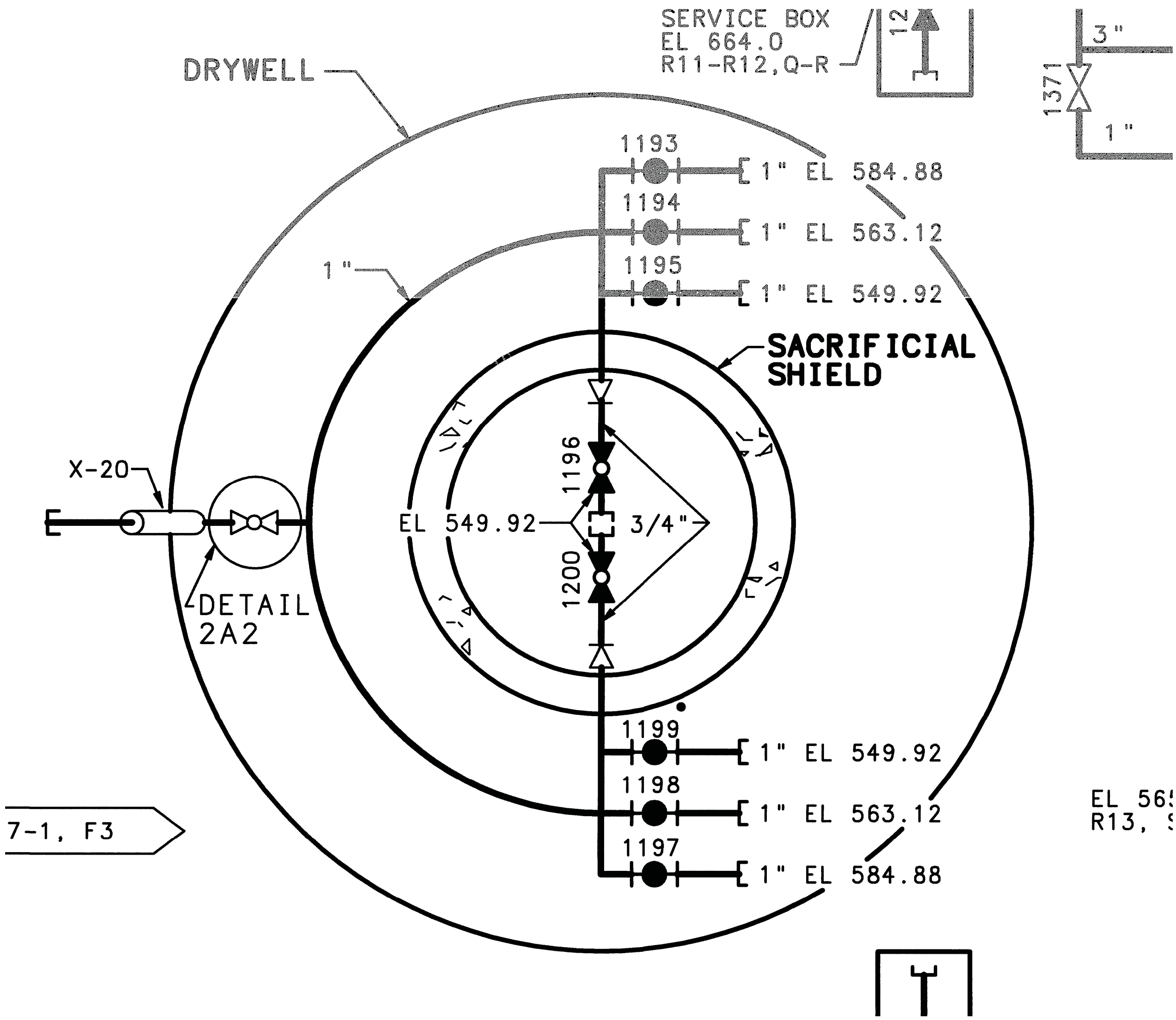
   The containment isolation valves associated with this system are as follows:

X-FCV-43-13	Inboard, Inside Containment
X-FCV-43-14	Outboard, Outside Containment

ENCLOSURE

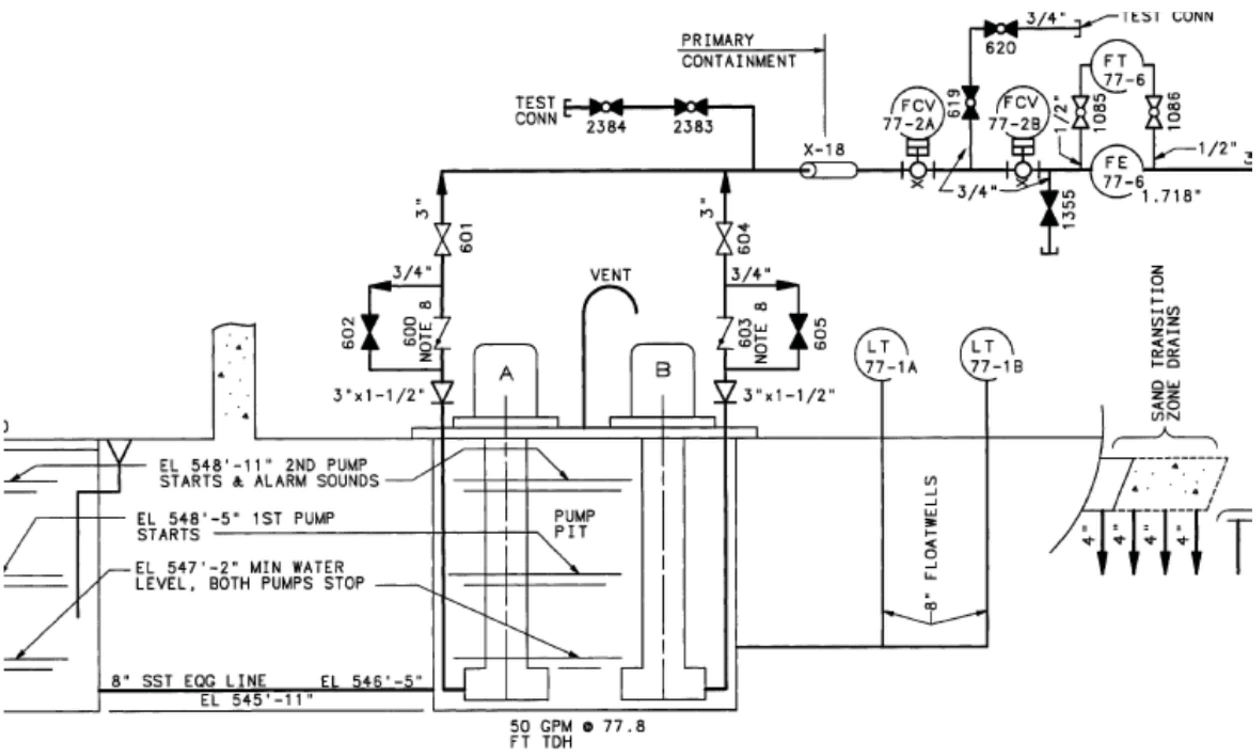
These valves are normally closed and are only opened when a sample is desired. The GL 96-06 piping under consideration is between the inboard and outboard isolation valves.

Figure SCVB-RAI 17-1
Clean Demineralizer System
(Typical of Units 2 and 3)



ENCLOSURE

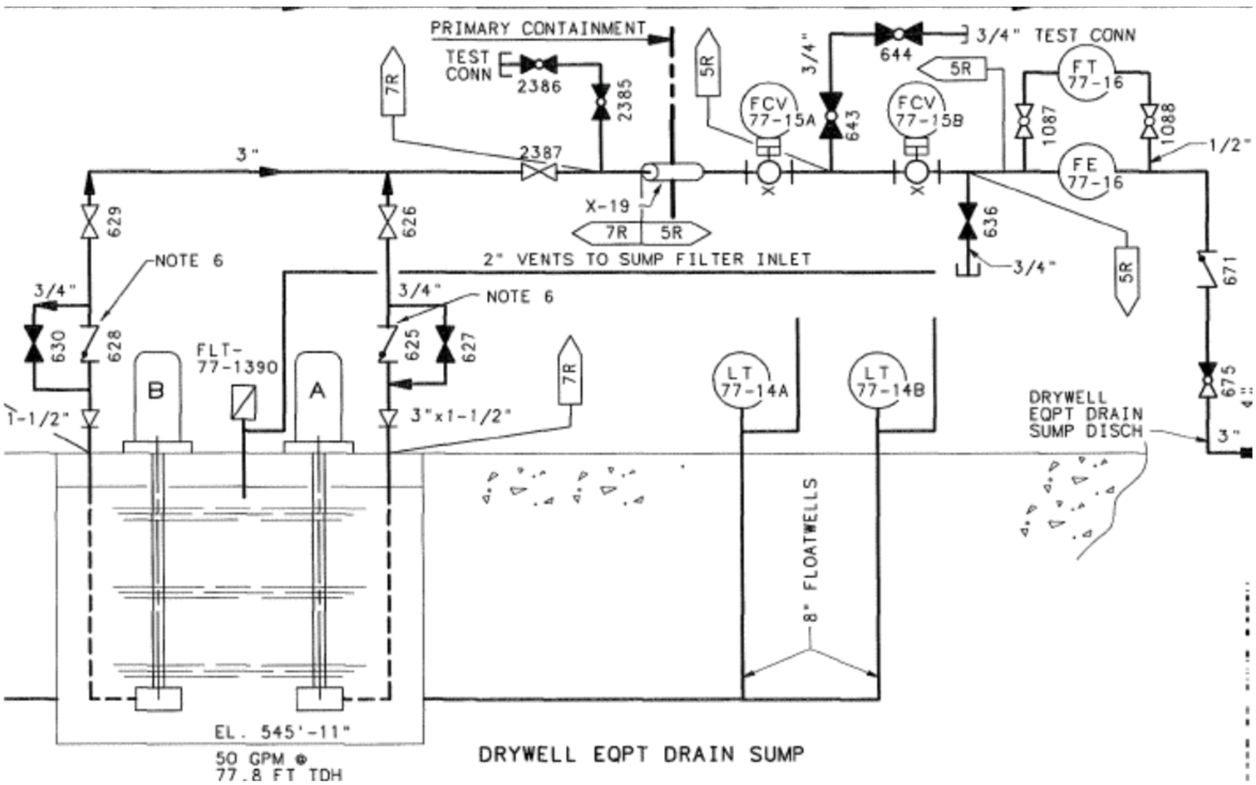
Figure SCVB-RAI 17-2
Drywell Floor Drain Sump System
(Typical of all three units.)



DRYWELL FLOOR DRAIN SUMP

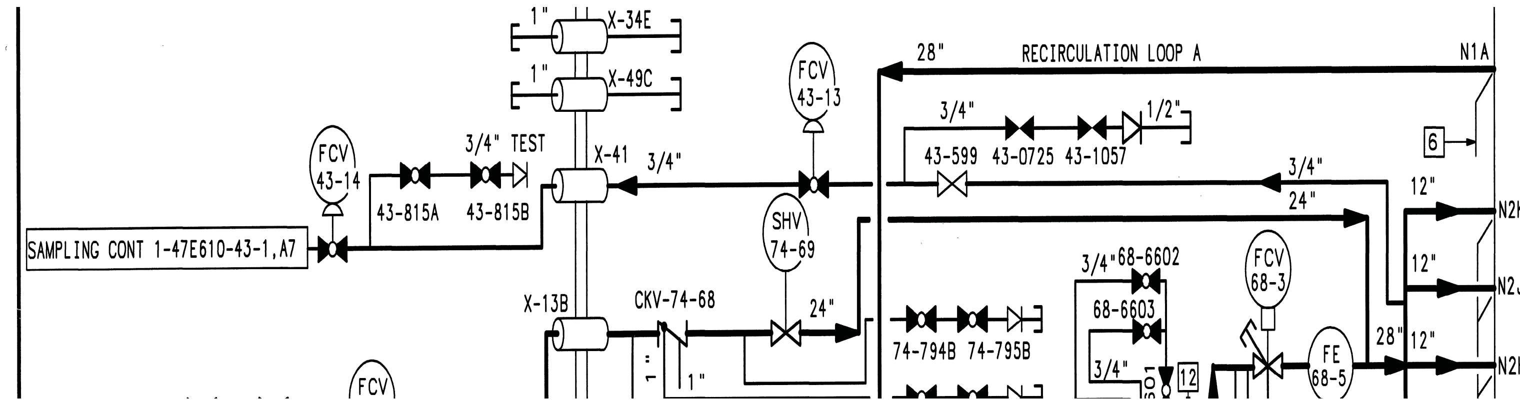
ENCLOSURE

Figure SCVB-RAI 17-3
Drywell Equipment Drain Sump System
(Typical of all three units.)



ENCLOSURE

Figure SCVB-RAI 17-4
Reactor Water Sampling System
(Typical of all three units.)



SCVB-RAI 18

Section 2.6.1.5 of PUSAR states that the drywell floor and drywell equipment drain sump discharge lines are acceptable because a 0.06-inch diameter orifice has been drilled in each discharge check valve. In UFSAR Table 5.2-2, the containment isolation valves listed for the drywell floor and equipment drain sump discharge are 3-inch ball valves (penetration Nos. X-18, and X-19). Please describe the location of the check valve in relation to the 3-inch ball valves and describe how the 0.06-inch orifice in the check valve would relieve the pressure between the containment isolation valves (3-inch ball valves).

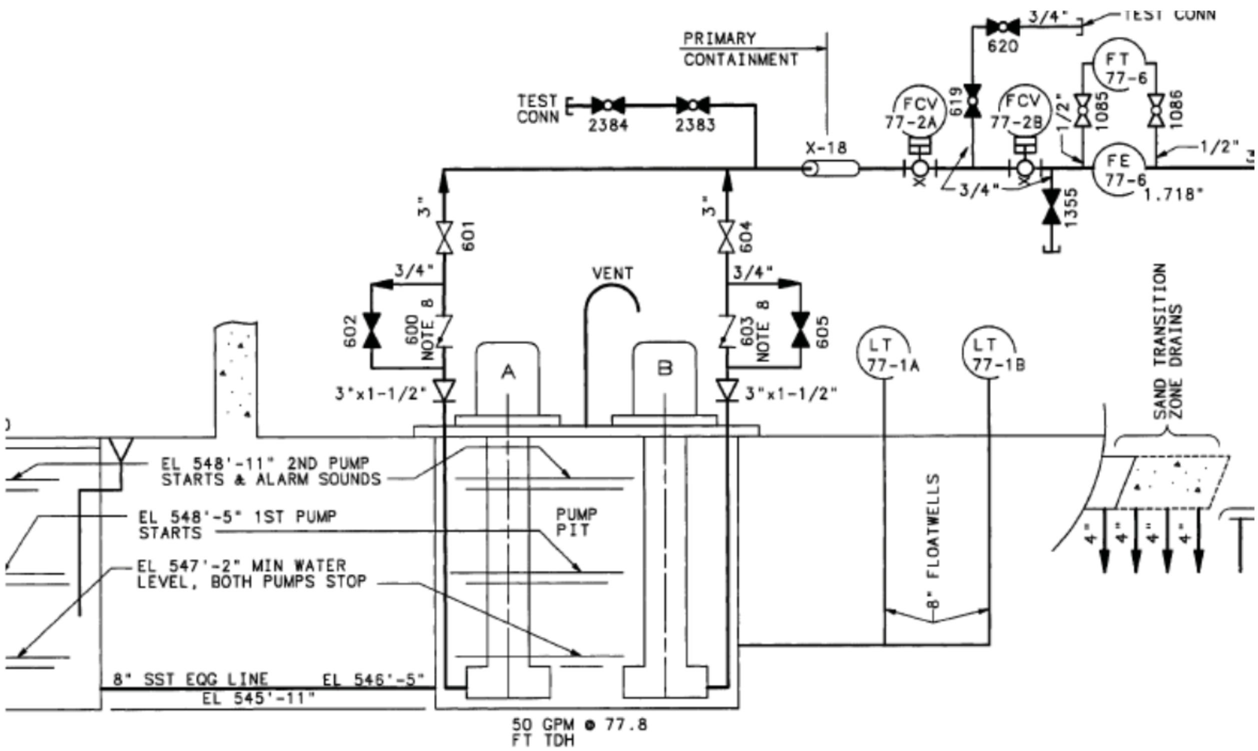
TVA Response:

See Figures SCVB RAI 18-1 and SCVB RAI 18-2 for the drywell floor and equipment drain sump.

The inboard and outboard isolation valves (3-inch ball valves FCV 77-2A and FCV 77-2B for penetration X-18 and FCV 77-15A and FCV 77-15B for penetration X-19) for primary containment are both located outside the drywell for the drywell equipment drain sump discharge piping and the drywell floor drain sump discharge piping. Therefore, the trapped water between the isolation valves is not subject to thermal over-pressurization during LOCA conditions. However, the water trapped between the inboard isolation valves and the sump pump discharge check valves (valves 600 and 603 for penetration X-18 and valves 625 and 628 for penetration X-19) would be subject to thermal over-pressurization. Each sump has two parallel pumps which connect to a common header before passing through the containment penetration. To protect against over-pressurization, a 0.06-inch hole has been drilled in each sump pump's discharge check valve, which will relieve any pressure build-up in the trapped water volume.

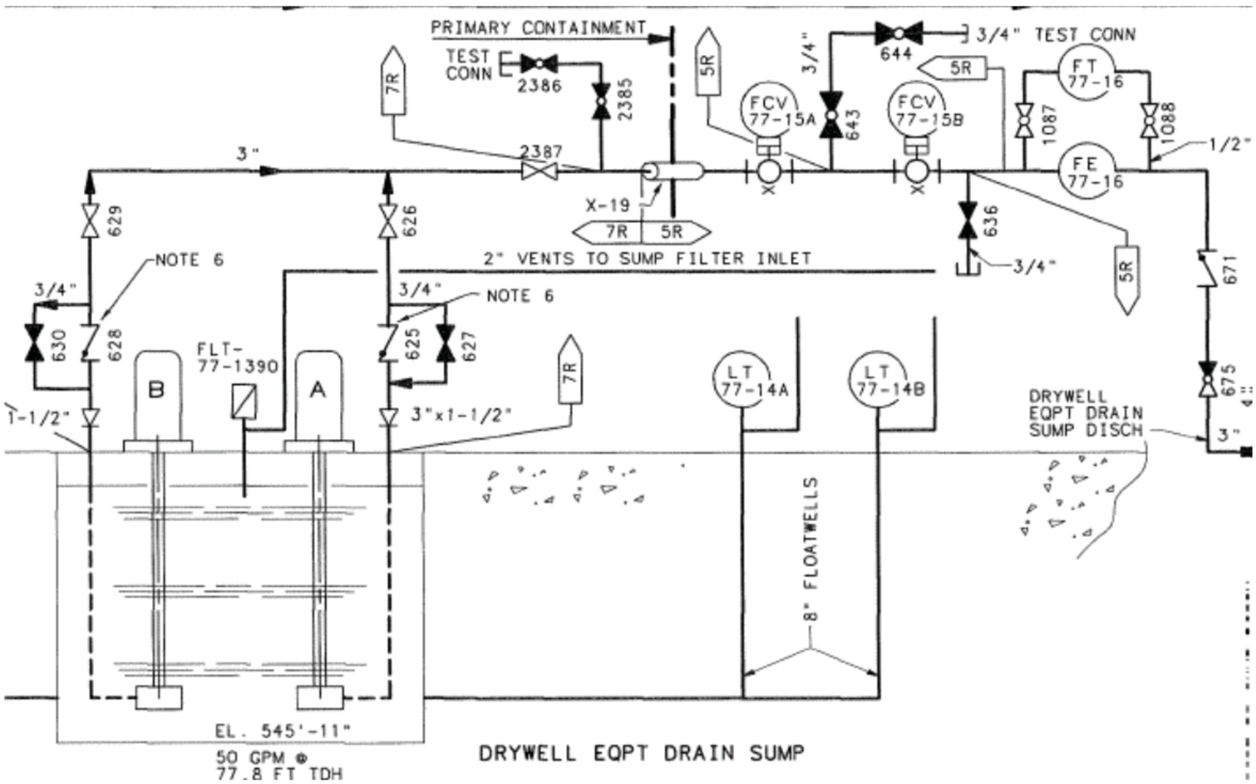
ENCLOSURE

Figure SCVB-RAI 18-1



DRYWELL FLOOR DRAIN SUMP

Figure SCVB-RAI 18-2



SCVB-RAI 19

Refer to Section 2.6.1.5 of PUSAR; confirm that all system lines for the containment isolation valves listed in UFSAR Table 5.2-2 have been evaluated for the GL 96-06 over-pressurization issue under EPU conditions.

TVA Response:

TVA confirms that all system lines for the containment isolation valves listed in UFSAR Table 5.2-2 have been evaluated for the GL 96-06 over-pressurization issue under EPU conditions.

SCVB-RAI 20

Section 2.6.1.5 of PUSAR states that thermally induced over-pressurization of the reactor sampling system at the current power using a constant drywell temperature of 336 °F following a LOCA reaches approximately 2,546 psig (pounds per square inch gauge), which will lift the inboard globe isolation valve disc.

a. What is the design pressure of these valves and the interfacing piping on both sides?

b. Are these valves designed to lift at 2,546 psig?

TVA Response:

a. The valves were hydrostatically tested by the manufacturer to 3250 psig. The maximum design pressure calculated for the interfacing piping per the design basis code of record is 4400 psig at 336°F.

b. These valves are not designed to specifically lift at 2546 psig. However, the globe valves have flow over the seat such that a pressure increase between the isolated valves could "lift" the inboard globe disc off its seat and relieve the pressure to the reactor vessel.

Conservatively using the piping design pressure of 1326 psig as reactor pressure, the following calculates the disc static force due to reactor pressure. (Note that the actual reactor pressure during a design basis LOCA is significantly below 1326 psig and the reactor pressure during the small break LOCA is closer to normal operating pressure.)

$$\begin{aligned} \text{Force}_{\text{static}} &= \text{Pressure}_{\text{static}} \text{ (Area of Disc - Area of Stem)} \\ &= 1326 \text{ psig } (\pi/4) \text{ [} (3/4 \text{ inch})^2 \text{- } (1/2 \text{ inch})^2 \text{]} \\ &= 325 \text{ lbf} \end{aligned}$$

The thermally-induced pressure between the isolation valves required to lift the inboard globe valve disc is the pressure that will exceed the force of the spring pre-load and the force of the upstream side pressure. This pressure is calculated as follows:

$$\begin{aligned} \text{Pressure}_{\text{Thermally-Induced}} &= (\text{Force}_{\text{static}} + \text{Force}_{\text{spring}}) \text{ / (Area of Disc)} \\ &= (325 \text{ lbf} + 800 \text{ lbf}) \text{ / } [(\pi/4)(3/4 \text{ inch})^2] \\ &= 2546 \text{ psig} \end{aligned}$$

Therefore, even with the conservative value assumed for reactor pressure, the valve would lift off its seat and relieve back to the reactor vessel well below the design pressure limits of the valve and surrounding piping.

SCVB-RAI 21

PUSAR, Section 2.6.1.5, describe the controls in place that will also be used under EPU conditions for draining the demineralized water system header prior to power operation in each cycle.

TVA Response:

The Unit 1 demineralized water penetration was cut and capped by a modification and some of the piping inside the drywell has been removed. The possibility for pressurization due to heat-up of trapped water in the piping no longer exists for this line on Unit 1. Therefore, no controls are needed for draining the demineralized water header prior to power operations.

The Units 2 and 3 demineralized water penetration has been cut and capped but this penetration is still used to supply demineralized water to the drywell during outages. The piping internal to the drywell remains so the possibility of pressurization due to heat-up of trapped water in the piping still exists. The pressurization boundary would be between the cap located outside of containment and the system isolation valves located inside containment (See Figure SCVB-RAI 17-1). The control in place to prevent over-pressurization due to heat up is that the unit start-up valve checklist procedure, 0-OI-2C/ATT-1B(C), “Attachment 1B(C) Valve Lineup Checklist,” requires that a demineralized water valve, located at the low point of the system in the drywell, be opened and left open for the cycle (Valves 2-SCV-002-1199 and 3-SHV-002-1199). The procedure checklist requires that the low point valve is verified open by a first operator and then independently verified as open by a second operator. Leaving these valves open will allow any water trapped in the pipe to escape to the drywell floor should the water expand due to heat-up from an event.

SCVB-RAI 22

Section 2.6.1.1.2 of PUSAR provides a discussion of the impact of drywell-to wetwell steam bypass and concluded that EPU requires no change to the existing TS surveillance requirement (SR) 3.6.1.1.2 that is to detect flow paths between the drywell and wetwell whose total capacity is equal to or greater than the capacity of a 1-inch diameter plate orifice (a 1-inch plate orifice has an effective area capability, A/√K, of approximately 0.0033 ft^2).

As per NUREG-0800 Standard Review Plan, Section 6.2.1.1.C, Revision 7, Appendix A, Section B, item 2.c, the acceptance criterion for Mark I containments with regard to steam bypass leakage, is that the measured leakage should not be greater than the leakage that would result from a 1-inch diameter opening (A/√K approximately 0.0033 ft^2). What is the value of A/√K derived from the SR 3.6.1.1.2 which reads as follows?

> *Verify drywell to suppression chamber differential pressure does not decrease at a rate > 0.25 inch water gauge per minute over a 10 minute period at an initial differential pressure of 1 psid [pounds per square inch differential].*

TVA Response:

The value of A/√K derived from the TS SR 3.6.1.1.2 statement cited in SCVB-RAI 22 is approximately 0.0033 ft^2.

SCVB-RAI 23

Section 2.6.1.2.1 of PUSAR provides an evaluation of increase fatigue usage factor of wetwell components due to an increased duration in chugging cycles from 900 seconds to 1200 seconds. Clarify that this evaluation is also applicable to the EPU conditions.

TVA Response:

The evaluation of increased fatigue usage factor of wetwell components due to an increased duration in chugging cycles from 900 to 1200 seconds, presented in Section 2.6.1.2.1 of the PUSAR, is applicable to both the BFN current licensing basis as well as the proposed EPU. There is no difference in the evaluation at either the BFN current power level or the proposed EPU power level for the impact of increased chugging cycles. The increased chugging duration to 1200 seconds is a result of the issue identified in Reference 1 concerning a possible delay in initiating drywell spray and is independent of the plant power level.

Chugging loads are not affected by the issued identified in Reference 1. Chugging loads result from the collapse of steam bubbles that form at the vent exit and can be influenced by vent steam mass flux, vent flow air content, and suppression pool (SP) temperature. The Mark I test program (Reference 2) investigated chugging loads for mass fluxes between 1 lb/sec-ft^2 and 6.5 lb/sec-ft^2, suppression pool temperatures between 65°F and 135°F, and air content between 0.01% and 1% of total vent flow. This envelops the spectrum of break sizes (i.e., DBA through Small Break Accident (SBA)) that are applicable to Mark I containment plants. The design loads for BFN are in accordance with the Reference 3 load definition and are also based on the Reference 2 test data. The range of conditions used in the Mark I full scale test facility tests was established to bound all Mark I plants for the submerged structure and SP boundary chugging loads. The chugging load definition thus represents an envelope of the data from the tests. The thermal-hydraulic conditions for these tests (i.e., steam mass flux, air content, and SP temperature) were selected to produce the maximum chugging amplitudes possible with a Mark I containment geometry. Therefore, the current chugging load definitions remain applicable at EPU conditions.

References

1. GE Nuclear Energy Safety Communication, SC 11-10, “Interruption/Delay in RHR Drywell Spray Initiation,” November 14, 2011.
2. GE Nuclear Energy, "Mark I Containment Program- Full Scale Test Program, Final Report," NEDO-24539, August 1979.
3. GE Nuclear Energy, “Mark I Containment Load Definition Report (LDR),” NEDO-21888, Revision 2, November 1981.

SCVB-RAI 27

Section 2.6.6 of the PUSAR, under "Technical Evaluation," states:

> *Because the maximum dome pressure is also not changed for EPU, there is no effect to the ability of secondary containment to contain mass and energy released to it. There is no increase in mass and energy released to secondary containment for EPU.*

a. Please explain, what is meant by "ability of secondary containment to contain mass and energy released to it."

b. Which break mass and energy released in the secondary containment is being referred to in the above statement?

c. What is the relationship between the reactor dome pressure and the mass and energy released to the secondary containment?

TVA Response:

a. The statement concerns the ability of the secondary containment and the Standby Gas Treatment System (SGTS) to maintain post-Loss of Coolant Accident (LOCA) effluent volume within design and regulatory limits. As stated in Section 4.4 of the NRC safety evaluation for NEDC-33004P-A (Reference 1), the design flow capacity of the SGTS is not affected by constant pressure power uprate (CPPU) because the specified primary and secondary containment leak rates are not changed by the power uprate. The BFN primary-to-secondary containment design leak rate of two percent of the primary containment volume per day is unaffected by power uprate. As such, there is no increase in the mass and energy released to the secondary containment from the primary containment due to EPU implementation.

b. The above statement (response to "a") is in reference to a LOCA inside primary containment. The function of the SGTS is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

c. An increased reactor dome pressure would result in a higher mass and energy release into the primary containment during a DBA. The mass and energy release from the primary-to-secondary containment is determined by the primary-to-secondary containment leak rate that is unchanged for the proposed BFN EPU. The statement "because the maximum dome pressure is also not changed for EPU" is to re-iterate that the BFN EPU is a CPPU. The design flow capacity of the SGTS is not affected by CPPU because the specified primary and secondary containment leak rates are not changed by the power uprate. Because the design flow capacity of the SGTS is unchanged with CPPU and because there is no increase in the primary-to-secondary containment leak rate with CPPU, the SGTS is able to maintain the secondary containment at negative pressure and thereby contain mass and energy released to the secondary containment.

Reference

1. GE Nuclear Energy, "Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003 (ML032170343); and NEDO-33004 (Non-Proprietary), July 2003 (ML032170332).

SCVB-RAI 28

Table 2.6-1 of PUSAR states peak drywell temperature of 297 °F for Units 2 and 3, and 295.2 °F for Unit 1 in the current licensing basis analysis. Table 2.6-1 shows 336.9 °F EPU long-term drywell gas temperature for the SSLB which is a significant change from the current drywell peak temperatures. The statement in Section 2.6.6 of PUSAR "The secondary containment temperature and pressure are not evaluated further in the Constant Pressure Power Uprate Licensing Topical Report because there is no effect as a result of EPU" does not appear to be correct because of large change in the drywell temperature.

a. *Provide an evaluation of the secondary containment pressure and temperature response under EPU conditions. State all assumption and changes in the analysis inputs from the current licensing basis.*

b. *Provide an evaluation of the Standby Gas Treatment System (SGTS) drawdown time, flow capacity, and iodine removal capacity based on the secondary containment conditions at EPU.*

TVA Response:

The current licensing basis peak drywell temperatures (297°F for Units 2 and 3, and 295.2°F for Unit 1) are not directly related to the PUSAR Table 2.6-1 EPU peak drywell temperature of 336.9°F for the small steam line break. Note 8 of PUSAR Table 2.6-1, applied to the CLTP peak drywell temperature results, states

> "This value is for a recirculation line liquid break. The Unit 2 and Unit 3 peak drywell airspace temperature for a steam line break is 336ºF (Reference 104). The Unit 1 peak drywell airspace temperature for a steam line break is 335.4ºF (Reference 105)."

The recirculation line liquid break is the recirculation suction line DBA LOCA.

A comparison, based on the different LOCA events, of CLTP versus EPU peak drywell temperature is:

Parameter	CLTP - DBA LOCA	EPU -with EPU Model - DBA-LOCA	CLTP - Steam Line Break LOCA	EPU - with EPU Model - Steam Line Break LOCA
Peak Drywell Temperature (°F)	297 - U2, U3 295.2 - U1	297.5 (D) 295.8 (B) 295.2 (R)	336 - U2, U3 335.4 - U1	336.9

The initial drywell temperature conditions for the EPU DBA LOCA Design (D), Bounding (B), and Reference (R) results are stated in Note 7 below PUSAR Table 2.6-1. The above table shows that the peak drywell temperature at EPU increases by a maximum of 2.3°F (297.5°F - 295.2°F) for the DBA-LOCA and 1.5°F (336.9°F - 335.4°F) for the steam line break LOCA, which is not significant.

TVA evaluated the effect of the EPU drywell temperature response profiles on the reactor building (secondary containment) temperature response. The results of the evaluation showed a maximum increase of less than 6°F (maximum increase is for the Unit 3 Torus room) for all reactor building rooms and reactor building general area temperatures and specifically a less than 2°F maximum increase in the refuel floor temperature. The BFN SGTS trains take suction from the refuel floor atmosphere for evacuating and maintaining the BFN secondary containment at negative pressure following a LOCA. The reactor building pressure increase due to this small increase in temperature is insignificant.

The small increase in the SGTS inlet temperature will insignificantly decrease the SGTS mass flow capability. An increase in secondary containment temperature of 10ºF results in less than a 2% decrease in SGTS mass flow capability on the basis of the change in air density calculated using the ideal gas law and the constant volumetric delivery characteristic of fans. Therefore, EPU will insignificantly affect the secondary containment drawdown time by the SGTS. The iodine removal capability of the SGTS is not affected by the small changes in the peak primary containment temperatures at EPU conditions because the secondary containment conditions are not significantly affected by the small changes in the primary containment temperatures.

SCVB-RAI 29

In Reference 6 under the Introduction section states:

> *The PUSAR uses GEH GE14 fuel as the principal reference fuel type for the evaluation of the impact of EPU. However, the BFN units will utilize AREVA ATRIUM 10XM fuel, with the potential for some legacy ATRIUM 10 fuel, under EPU conditions.*

The various containment analysis presented in Section 2.6 of PUSAR are based on the sensible and decay heat from GE14 fuel. There is no quantitative comparison provided between the fuel characteristics for GE14 and the ATRIUM 10XM or ATRIUM 10 fuel from a containment analysis standpoint.

Considering the differences between GE14 and ATRIUM 10 XM or ATRIUM 10 fuel such as mass, material properties, core flow, decay heat, heat transfer coefficients between the core and the coolant, and any other variations, justify the LOCA mass and energy release in the containment based on GE14 fuel is bounding and the various containment analysis based on GE14 fuel mass and energy release presented in Section 2.6 of PUSAR will remain bounding.

TVA Response:

The safety analysis codes used in the containment analyses, SHEX, LAMB, and M3CPT use neither detailed reactor kinetics nor detailed fuel rod response characteristics. The results of these safety analyses in the short term (M3CPT with LAMB codes) are primarily driven by reactor and containment gross thermal-hydraulic initial conditions (core thermal power, reactor pressure, reactor water level, total core flow, core inlet subcooling, containment pressure, containment temperature and containment relative humidity). The results in the long-term (SHEX code) are primarily driven by reactor decay heat, the suppression pool (torus) heat capacity, and the capacity of the containment heat removal system. In the above containment analysis codes, the sensible and latent heat contribution from the fuel assembly mass to the reactor coolant and subsequently to the containment is performed by modeling the fuel mass (uranium oxide (UO_2)) and non-UO_2 fuel assembly mass (fuel cladding, fuel channel, etc.) as a single node. Both the fuel mass (UO_2) and non-UO_2 fuel assembly mass assumed in the BFN containment analyses are approximately 10% greater than the actual fuel mass and non-UO_2 fuel assembly mass for a BFN core composed of either ATRIUM-10 or ATRIUM-10XM fuel. The fuel bundle mass for ATRIUM-10XM fuel is slightly greater than the fuel bundle mass for ATRIUM-10 fuel.

Section 2.8.1 of EPU LAR Attachment 8, Fuel Uprate Safety Analysis Report (FUSAR), pages 35 through 37, contains a comparison of a limiting GE14 fuel decay heat profile to a limiting decay heat profile for the ATRIUM-10 fuel type. The comparison used the same analysis basis, and showed the difference in decay heat fraction to be very small. The ATRIUM-10 XM fuel design was shown to have comparable decay heat to the ATRIUM-10 fuel. The table on page 36 of the FUSAR demonstrates that the fission fractions for U-235, U-238, and Pu-239 are very similar between the GE14, ATRIUM-10, and ATRIUM-10 XM fuel types, which further illustrates the lack of sensitivity of decay heat to the fuel type. These comparisons support the conclusion that the GE14 decay heat profile used in the EPU containment analyses adequately bounds the decay heat of the ATRIUM-10 or ATRIUM-10XM fuel designs, or a core containing a mixture of both AREVA fuel types.

SCVB-RAI 31

In PUSAR Section 3, “References”, the Reference 88, “GE Nuclear Energy, ‘Mark I Containment Program- Full Scale Test Program, Final Report,’ NED0-24569, August 1979 does not appear to be correct reference. Is it NEDO-24539 instead of NEDO-24569? Clarify or correct.

TVA Response:

TVA confirms that LAR Attachment 6 (PUSAR), Section 3.0, Reference 88 is:

> GE Nuclear Energy, "Mark I Containment Program- Full Scale Test Program, Final Report," NEDO-24539, August 1979.

SCVB-RAI 33

Refer to the following assumption in response to SCVB RAI-1(l), regarding the method of as-found heat-exchanger inspection for determining the number of plugged tubes and the resulting effective heat transfer area.

> *It is assumed that all tubes were unobstructed during the test (i.e., none of the tubes were plugged by macro fouling during the test). It is an inherent part of the PROTO-HX method of analysis to distribute the tube-side flow equally to all tubes and to use the specified heat transfer area in the fouling calculation. This assumption is acceptable since lost area due to unknown macrofouling will show up as extra fouling resistance.*

a. According to the above assumption, since the number of plugged tubes is unknown, the PROTO-HX analysis would use the cross-sectional area of all tubes which is obviously greater than the actual cross-sectional flow area during the test because of plugged tubes. The tube flow velocity calculated by PROTO-HX would therefore be less than the actual tube flow velocity in the test. Please explain how the difference in tube velocity is accounted for in determining the tube side heat transfer coefficient.

b. According to the above assumption, since the number of plugged tubes is unknown, the PROTO-HX analysis would use the clean heat exchanger maximum design heat transfer area of all tubes which is obviously greater than the actual heat transfer area during the test. Justify <u>quantitatively the equivalency</u> [emphasis added] of <u>lost heat transfer area due to unknown macrofouling</u> (unknown number of plugged tubes) with <u>showing up of extra fouling resistance</u> so that the heat exchanger overall heat transfer coefficient (UA) output from the PROTO-HX analysis is conservative (minimum) and bounded by the actual (UA) of the tested heat exchanger.

TVA Response:

a. The tube side heat transfer coefficient can be determined from formulas documented in heat exchanger design literature and text books. ASME OM-2015, Part 21 Nonmandatory Appendix C, Section C2.1.7 provides formulas (shown below) for the inside film coefficient, h_i (Btu/hr-ft^2-°F) for turbulent and laminar flows and also provides formulas for the Reynolds Number (Section C2.1.5). Because the velocity term appears in the numerator when calculating the Reynolds number and the Reynolds number term appears in the numerator when calculating the inside film coefficient, an increased velocity results in an increased inside film coefficient, h_i, and similarly, a decreased velocity results in a decreased inside film coefficient. Because the PROTO-HX assumed tube side flow velocity would be lower than the actual tube side flow velocity, the PROTO-HX calculated inside film coefficient would also be lower. Consequently, use of the lower velocity in PROTO-HX would result in a lower overall heat transfer coefficient.

For turbulent flow, $Re_d > 10{,}000$

$$h_{i,d} = 0.023(12k_d/d_i)(Re_d)^{0.8}(Pr_d)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

For laminar flow, Re_d <2,100

$$h_{i,d} = 1.86(12k_d/d_i)(Re_d)^{1/3}(Pr_d)^{1/3}(d_i/L)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

where,
d_i = inside diameter of tube, in.
$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions
k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid at design accident conditions, from the reference in subparagraph 3.2(e)
L = total length of tube, in., carrying flow, from design specification sheet or drawings
Pr_d = Prandtl number (dimensionless) of the tube side fluid at design accident conditions
Re_d = Reynolds number (dimensionless) of the tube side fluid at design accident conditions
μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in subparagraph 3.2(f)
$\mu_{w,d}$ = absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature at design accident conditions, from the reference in subparagraph 3.2(f)

For Reynolds Number,

$$Re_d = (124 p_d V_d d_i)/\mu_d$$

where,
d_i = inside diameter of tube, in.
Re_d = Reynolds number (dimensionless) of the tube side fluid at design accident conditions
V_d = tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at design accident conditions
μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)
p_d = bulk density, lbm/ft^3, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)

b. ASME PTC 12.5-2000, “Single Phase Heat Exchangers”, Nonmandatory Appendix G - Fouling Resistance, equation (G.1) calculates the total heat transfer resistance, r_{total}.

$$r_{total} = A \times EMTD \div Q$$

If it were possible to test the heat exchanger under clean conditions, $r_{total} = r_{clean} = 1/U_{clean}$

The fouling resistance, r_f is determined by equation (G.2)

$$r_f = r_{total} - r_{clean}$$

where A is the heat transfer area, EMTD is the Effective Mean Temperature Difference, which can also be expressed as f x LMTD, where LMTD is the Log Mean Temperature Difference and f is the LMTD correction factor, and Q is the heat transfer rate.

The Q and EMTD are determined based on measured temperatures and flow rates (from the test).

Inspection of the above formulas shows that if the large area, A is being used in PROTO-HX along with the measured temperature differences, then the calculated fouling resistance from the test, r_f, will also be a large number. Stated another way, if the actual (smaller) area were to be used along with the measured temperature differences, then the calculated fouling resistance would be smaller which would be non-conservative for comparison to the acceptance criterion.

In order to have an acceptable test, the fouling resistance determined from the test data using the larger area (used in PROTO-HX) must be less than or equal to the fouling resistance acceptance criteria. The larger area (used in PROTO-HX) results in a larger fouling resistance which is conservative for comparison to the fouling resistance acceptance criterion.

In PROTO-HX the Q and LMTD (and f) are determined from the test data. The equation Q = U x A x f x LMTD can be rewritten to solve for the test U, U_{test} = Q ÷ (A x f x LMTD) it can be seen that the large area, A, results in a lower U_{test} and thus, the larger area used in PROTO-HX is conservative in reporting the tested heat transfer capability of the heat exchanger.

In PROTO-HX there is a difference in the treatment of tubes mechanically plugged (known) and the number of tubes that may be obstructed (unknown). The known number of tubes mechanically plugged is used in determining the heat exchanger surface area input to PROTO-HX. Conversely, the number of tubes that may be obstructed by macrofouling (debris) remains unknown until the heat exchanger can be opened and inspected. The basis for the assumption discussed in the response to SCVB RAI-1(l) is that it is acceptable to not account for the number of tubes that could be obstructed by macrofouling because any obstruction would show as extra fouling resistance. In summary, the PROTO-HX model distinguishes between tubes mechanically plugged (excluded from the effective tube surface area) and tubes that may be obstructed by macrofouling during the test (included in the effective tube surface area).

Therefore, the number of additional tubes that could be plugged during the test are conservatively accounted for in the test methodology through the application of the area used in PROTO-HX.