TVA

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TVA-BFN-TS-431

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U.S. Nuclear Regulatory Commission
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In the Matter of	)	Docket Nos. 50-259
Tennessee Valley Authority	)	50-260
		50-296

BROWNS FERRY NUCLEAR PLANT (BFN) – UNITS 1, 2, AND 3 – TECHNICAL SPECIFICATIONS (TS) CHANGES TS-431 AND TS-418 – EXTENDED POWER UPRATE (EPU) – RESPONSE TO ACRS MEMBER CONCERNS AND RECOMMENDATIONS REGARDING CREDITING CONTAINMENT OVERPRESSURE (COP) CREDIT

By letters dated June 28, 2004 and June 25, 2004, TVA submitted license amendment requests (LARs) to the NRC for the EPU operation of BFN Unit 1, and BFN Units 2 and 3, respectively. The LARs would increase the maximum thermal power level of each reactor by 14.2 percent to 3952 megawatts. In the supporting analyses, additional COP credit was required for the Loss-of-Coolant Accident (LOCA) analysis and for 3 special event analyses.

In a letter dated March 18, 2009, the Advisory Committee on Reactor Safeguards (ACRS) provided conclusions and recommendations to the NRC staff to facilitate the resolution of the COP credit issue. To provide a comparison between BFN's EPU license application with the ACRS recommendations, TVA has included a response to the items from the ACRS letter in Enclosure 1. In brief, the BFN EPU application addresses the elements of the ACRS letter. On November 10, 2008, ACRS sent a letter to the staff transmitting ACRS member questions on COP specifically related to BFN's EPU application. To aid in the review of BFN's EPU, a response to these ACRS questions is provided in Enclosure 2. Below is a brief history regarding ACRS issues on BFN COP and a summary of recent TVA submittals that were performed to address ACRS concerns.

During the review of the BFN Unit 1 LAR for uprate to 105% of original licensed thermal power, ACRS concluded that the use of COP credit in the EPU licensing analyses for the

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long-term large LOCA and the Appendix R event would require more complete evaluations and also expressed reservations on the magnitude and duration of COP credit being requested in the Appendix R analysis. These concerns were documented in the February 16, 2007, ACRS letter to the staff on the BFN Unit 1 105% LAR.

On June 12, 2008, TVA submitted a response to the ACRS concerns. This submittal provided the results of an alternative fire evaluation characterizing the consequences of more realistic fire scenarios in contrast to the deterministic licensing basis Appendix R analysis. The alternative fire evaluation concluded that for realistic fire events, COP was needed in only 2 out of the 39 total fire areas and that for the 2 fire areas, the magnitude and duration of COP would be very small (1.6 feet/6 hours). The June 12 submittal also summarized previously submitted TVA evaluations, which showed that the risk of dependence on COP for LOCA, Anticipated Transient Without Scram, and Station Blackout events was very small (Delta Core Damage Frequency = 2.4E-8/year).

In follow-up to the ACRS concerns, on March 12, 2009, TVA submitted the results of a revision to the net positive suction head (NPSH) /COP calculations for short-term (ST) LOCA and Appendix R, which used more realistic inputs/assumptions. The revised ST LOCA results showed a reduction in the amount of COP credit needed and that the available NPSH (NPSHa) always exceeded required NPSH (NPSHr). Previously, NPSHa was less than NPSHr for approximately 4 minutes in the ST-LOCA analysis. In the revised Appendix R analysis, the duration and magnitude of COP credit was reduced, and importantly the margin to the available containment pressure increased from 3.7 feet to 9.5 feet. Lastly, on May 7, 2009, TVA submitted an additional Appendix R calculation that shows that NPSHa remains greater than NPSHr with all drywell coolers in operation for the duration of the event. Therefore, operator action to terminate drywell cooling is not required to maintain COP.

Enclosure 3 provides a table comparing the EPU COP requirements for LOCA between BFN and several Boiling Water Reactors (BWRs) of similar design vintage for a perspective on the amount of COP credit being requested by BFN. The table shows that the amount of LOCA COP being requested by BFN EPU is comparable to or less than that previously approved for other BWR EPU applications.

TVA has determined that the additional information provided by this letter does not affect the no significant hazards considerations associated with the proposed TS changes. The proposed TS changes still qualify for a categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9).

No new regulatory commitments are made in this submittal. If you have any questions regarding this letter, please contact J. D. Wolcott at (256) 729-2495.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 16th day of July, 2009.

Sincerely,

R. G. West
Site Vice President

Enclosures:

1. Response to March 18, 2009, ACRS Letter - Conclusions And Recommendations Regarding Crediting Containment Overpressure (COP) Credit
2. Response To November 10, 2008, ACRS Letter Concerns Regarding Containment Overpressure (COP) Credit For BFN EPU
3. Comparison of BFN EPU LOCA Containment Overpressure (COP) Credit with other EPU BWRs

Enclosures:

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ENCLOSURE 1

**TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3**

**TECHNICAL SPECIFICATIONS (TS) CHANGES TS-431 AND TS-418
EXTENDED POWER UPRATE (EPU)**

**RESPONSE TO MARCH 18, 2009 ACRS LETTER
CONCLUSIONS AND RECOMMENDATIONS REGARDING CREDITING CONTAINMENT OVERPRESSURE (COP) CREDIT**

By letters dated June 28, 2004 and June 25, 2004 (ADAMS Accession Nos. ML041840109 and ML041840301), TVA submitted license amendment requests (LARs) for the EPU operation of BFN Unit 1 and BFN Units 2 and 3, respectively. The proposed amendments would change the operating licenses to increase the maximum authorized core thermal power level of each reactor by approximately 14 percent to 3952 megawatts. In the supporting EPU analyses, additional COP credit was requested for the Loss-of-Coolant Accident (LOCA) analysis and for 3 special event analyses.

In the Advisory Committee on Reactor Safeguards (ACRS) review of the BFN Unit 1 LAR for uprate to 105% of original licensed thermal power, ACRS concluded that the use of COP credit in the EPU licensing analyses for the long-term (LT) large LOCA and the Appendix R event required more complete evaluations, and, in particular, expressed reservations about the magnitude and duration of COP credit being requested in the Appendix R event analysis. These concerns were documented in the February 16, 2007, ACRS recommendation letter (ML070470314) to the NRC staff on the BFN Unit 1 105% LAR. TVA submitted a response to the ACRS concerns in a letter dated June 12, 2008 (ML081700294), which was followed with a formal presentation to ACRS on July 10, 2008.

On March 18, 2009, ACRS issued a letter (ML090700464) report titled "Crediting Containment Overpressure in Meeting the Net Positive Suction Head Required to Demonstrate that the Safety Systems Can Mitigate the Accidents as Designed." To aid in the review of BFN EPU, TVA has performed a comparison of the BFN approach in crediting COP for EPU with the recommendations set forth in the March 18, 2009, ACRS letter report. The results of this comparison are provided below to each of the Conclusions and Recommendations listed in the ACRS letter report.

<u>ACRS Recommendation 1</u>

To preserve safety margin in all reactors, credit for COP should be limited in amount and duration. Licensees requesting such credit should continue to be required to demonstrate that it is not practical to reduce or eliminate the need for overpressure credit by hardware changes or requalification of equipment.

BFN EPU Comparison with ACRS Recommendation 1

For the Anticipated Transient Without Scram (ATWS) and Station Blackout (SBO) special events, the required COP for EPU is of small magnitude and short duration. For LOCA during the short-term (ST) phase (<10 minutes), a small amount of COP is needed for the Residual Heat Removal Pumps (RHR) and Core Spray (CS) pumps. For the LT phase of LOCA (>10 Minutes), a maximum of 3 pounds per square inch (psi) is needed for the CS pumps and the total duration of COP need is 22.5 hours. The RHR pumps, which are capable of core cooling as well as containment cooling in a LOCA event, do not require COP credit for LT LOCA. The largest amount of COP is needed for the Appendix R special event, which was originally calculated to be 9.6 psi with a total duration of 69 hours. The Appendix R licensing basis calculations have since been revised as discussed later in this enclosure and the magnitude and duration have been reduced to 6.1 psi with a total duration of COP need of 27.8 hours. The Appendix R analysis is the limiting case because only 1 RHR pump/RHR heat exchanger is available for event mitigation.

BFN has evaluated several plant modifications that have the potential to reduce the amount of required COP or which could eliminate the need for COP. These options involve either increasing pump suction pressure by increasing elevation head or decreasing water temperature by increasing containment heat removal capability. Since the Appendix R event has the most COP need, consideration was focused on modifications that would impact Appendix R. A discussion of modification options is provided below.

- **Increase Static Elevation Head Available to RHR and CS Pumps**

  The static head available to the RHR and CS pump suctions could be improved by physically lowering the pumps or by raising the suppression pool water level.

  Boiling Water Reactor plants constructed after BFN's vintage typically installed deep well vertical Emergency Core Cooling System (ECCS) pumps that are recessed into the floor slab. This configuration increases the elevation head at the pump suction. Since the BFN ECCS pumps are already located at the lowest elevation of the reactor building, installing deep well pumps would require major excavation of the basemat of the reactor building in 12 basement areas (4 per unit) where the RHR and CS pumps are located. Because this would require major excavation inside the reactor building structure below the elevation of the basemat, installation of deep well vertical pumps is impractical.

  Raising the normal suppression pool water level would also increase the static head available to the ECCS pumps and additionally would increase the water inventory in the suppression pool, both of which would have a beneficial effect on net positive suction head (NPSH). The maximum allowable suppression pool water level is, however, narrowly restricted by TS to provide for acceptable suppression pool structural loading combinations during LOCAs and safety relief valve (SRV) discharges. Therefore, raising the TS maximum allowable suppression pool water level is not a practical option.

- **Modify Fire Safe Shutdown Analysis - Implementation of NFPA 805**

  In the licensing basis Appendix R event, the postulated fire is assumed to damage all equipment located in a given fire area not meeting the physical separation and fire protection requirements of the Appendix R rule. This rule-based approach is very conservative and limits the plant equipment that can be credited in mitigating fire events. For BFN, the Appendix R rule-based analysis results in a single RHR pump and its heat exchanger being available for core and containment cooling. The specific RHR/RHR heat exchanger combination used in the safe shutdown analysis also varies depending on the specific fire area.

BFN has recently committed to adopt National Fire Protection Association (NFPA) Standard 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," in a submittal dated March 4, 2009 (ML090650597). NFPA 805 allows for consideration of fire hazards and risk insights to achieve compliance with fire protection regulations as an alternative to the prescriptive requirements of Appendix R. NFPA 805 will afford the opportunity to significantly reduce or eliminate COP credit by changing the complement of available equipment and how it is utilized in operating procedures (e.g., make available more than 1 RHR/RHR heat exchanger or use balance-of-plant equipment in more cases). This effort is in progress, but it will require 3 to 5 years to complete. Therefore, NFPA 805 is not a practical option to support EPU implementation with regard to COP in the near term.

- **Revision of Fire Safe Shutdown Methods - Protect Additional RHR pump/RHR heat exchanger**

  Making available a second RHR subsystem would eliminate the need for COP for Appendix R. The chief impediment is that modifications (e.g., cable separations, fire wrap, fire barriers) to accomplish this would have to the meet physical separation and other requirements of the Appendix R rule. Each additional credited RHR pump would require protection of power and control cabling, additional switchgear, and a diesel generator alternating current power source with its battery control power and control cabling. To provide cooling water to a second RHR heat exchanger, it would also be necessary to protect an additional RHR Service Water pump and its flow path along with associated power and control cabling. The physical locations of key electrical distribution boards in some board rooms makes it difficult to ensure that 2 RHR pumps/heat exchangers would be available in all fire areas under the prescriptive Appendix R rule requirements. For instance, switchgear controlling an RHR pump from 1 RHR loop is currently located in the same electrical room as switchgear controlling the valves from the opposite loop.

  This option would involve a significant reanalysis and modification effort as well as the development of procedures for additional operator manual actions to power and align a second RHR pump and its supporting equipment. And as discussed above, BFN has recently committed to adopt NFPA Standard 805. A large scope project reanalyzing the current deterministic BFN Appendix R program is not congruent with a transition to NFPA 805, which would be proceeding in parallel. Therefore, TVA has concluded this is not a practical option.

- **Upgrade the RHR heat exchangers**

  The heat removal rating of the RHR heat exchangers could be increased by replacement of the existing RHR heat exchanger tube bundles with a redesigned tube bundle. Installation of higher rated RHR heat exchangers would reduce the magnitude and duration of the COP required for Appendix R events and would eliminate the need for

COP for LT LOCA. The modification would not, however, completely eliminate the need for COP credit in the Appendix R event and does not impact COP need for ST LOCA. This modification would require significant resources (>$10M per unit) and personnel dose commitment, requires several years of lead time for the design, procurement, and installation, and would provide only a partial COP remedy. Therefore, it is not a practical option to support EPU implementation with regard to COP in the near term.

ACRS Recommendation 2

Licensees should continue to be requested to use the current guidance in Regulatory Guide 1.82 Revision 3 [Ref. 2] and the licensing-basis analyses assumptions and methods to demonstrate that the available net positive suction head (NPSH) exceeds that required for operation of the emergency core cooling system (ECCS) and containment heat removal pumps.

BFN EPU Comparison with ACRS Recommendation 2

The EPU NPSH analyses for LOCA and the special events were performed using the guidance in Regulatory Guide (RG) 1.82 Revision 3, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident." Thermal-hydraulic analyses were performed to demonstrate that the available NPSH (NPSHa) would be greater than the ECCS pump vendor's required NPSH (NPSHr) assuming limiting thermal-hydraulic conditions and equipment failures specified in the plant's licensing basis. If COP was required, then additional analyses were performed to demonstrate the minimum expected containment pressure exceeded the NPSHr for ECCS pump operation.

The EPU NPSH/COP calculations for LOCA and the 3 special events were submitted to NRC on August 31, 2006 (ML062510371). The calculated containment pressure was always greater than NPSHr in all of the events except for a 4 minute duration in the ST LOCA analysis for the RHR pumps injecting into the broken recirculation loop. On March 12, 2009 (ML090720951), TVA submitted the results of a revision to the NPSH/COP ST LOCA analysis, which used more realistic inputs for the RHR broken loop pump flow and the initial drywell humidity. These changes resulted in a reduction in amount of required COP credit such that there was no longer a time period where NPSHa was less than NPSHr for ST LOCA. Therefore, the containment pressure exceeds that required for operation of the ECCS and containment heat removal pumps for all analyzed events.

A summary of current NPSH/COP calculations is presented in the table below.

Results of NPSH/COP Calculations				
	RHR Pumps		CS Pumps	
Event	Peak COP/Duration	Margin	Peak COP/Duration	Margin
ST LOCA intact recirculation loop	0.2 psi/3.2 minutes	2.6 psi	2 psi/8.9 minutes	1.3 psi
broken recirculation loop	2.1 psi/9.3 minutes	0.7 psi		
LT LOCA (> 10 minutes)	none required	-	3 psi/22.5 hours	3.1 psi
Appendix R - drywell cooling off at 2 hours	6.1 psi/27.8 hours	4.1 psi	pump not used	pump not used
Appendix R - drywell cooling always operating	5.9 psi/27.7 hours	1.5 psi	pump not used	pump not used
SBO	1.4 psi/1.4 hours	4.5 psi	pump not used	pump not used
ATWS	1.9 psi/1.2 hours	1.2 psi	pump not used	pump not used

ACRS Recommendation 3

Regulatory Guide 1.82 Revision 3 [Ref.2] should be revised to request that licensees submit additional analyses and information if the amount of accident pressure that must be credited based on the licensing-basis analyses is not a small fraction of the total containment accident pressure and limited in duration. The additional information should include thermal-hydraulic analyses, which address the conservatism associated with the licensing-basis analyses and explicitly account for uncertainties and probabilistic risk assessment (PRA) results consistent in scope and quality with that specified by Regulatory Guide 1.174 [Ref. 3].

BFN EPU Comparison with ACRS Recommendation 3

LOCA, ATWS, and SBO Risk Analysis

Additional thermal-hydraulic analyses were performed to determine which parameters were important to NPSH requirements and COP need. These analyses were submitted on March 23, 2006 (ML060880460). For the ATWS and SBO analyses, it was assumed that COP is always needed. The resulting success criteria were then used to address RG 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," guidelines for the LOCA, ATWS, and SBO events. This analysis was submitted July 21, 2006 (ML062090071) and showed that the risk of relying on COP was very small (Delta Core Damage Frequency = 2.4E-8/year) for these 3 events. Additionally, the ATWS event was reanalyzed using a best estimate model (TVA submittal dated August 4, 2006, (ML062220647)), which showed that COP was not needed when reactor power is modeled using the TRACG code as opposed to the ODYN code.

Fire Risk Analysis

In the Appendix R NPSH/COP calculations that were submitted on August 31, 2006, 9.6 psi of COP was required with a 69 hour total duration of some COP need. The NPSH margin was relatively small at 3.7 feet. On March 12, 2009, TVA submitted the results of revisions to the Appendix R COP analysis, which used an RHR NPSHr value based on the industry standard 3% total pump head loss criterion. RG 1.82 Revision 3 also defines NPSHr as the 3% head loss value. Incorporating this change resulted in reducing the duration and magnitude of COP credit to 6.1 psi with a 27.8 hour duration where some COP is needed. The NPSH margin increased substantially from 3.7 feet to 9.5 feet.

TVA also performed an alternative fire area evaluation to better characterize the likelihood and consequences of fire scenarios in contrast to the licensing basis Appendix R analysis. Fire events were analyzed using alternate, more realistic fire scenarios. Using basic principles of fire protection engineering such as combustible loading, room volume, and ignition sources, fire areas were screened for realistic impact of a fire on equipment. Thermal-hydraulic analyses were then performed for shutting down the plant with equipment not damaged by fire using plant emergency operating procedures. The fire area evaluation was submitted on November 15, 2007 (ML073230348) and later followed by the submittal of the thermal-hydraulic analysis results on June 12, 2008. In the alternative fire analysis, only 2 of the total 39 fire areas required COP. Additionally the amount of required COP was very small and limited in time duration (1.6 feet/6 hours). In the alternative analysis, core cooling is provided by balance-of-plant equipment and does not rely on the RHR pump to provide both core cooling and containment cooling, thus, addressing the defense-in-depth impact of COP.

ACRS Recommendation 4

For cases in which operator actions are required to maintain containment overpressure, licensees should show how these actions can be implemented in their procedures, that they can be performed reliably, and that any increase in risk associated with these actions is acceptably small.

BFN EPU Comparison with ACRS Recommendation 4

The Appendix R licensing basis analysis takes credit for operator action to terminate drywell cooling within 2 hours of the event initiation. Terminating drywell air space cooling increases drywell and wetwell pressure, which provides additional COP margin. The need for operators to take this manual action was cited as an ACRS concern in the February 16, 2007, letter on Unit 1.

The Appendix R NPSH/COP calculations have since been revised and show that NPSHa remains greater than NPSHr with the drywell coolers remaining in operation for the entire duration of the event. TVA submitted the revised analysis and calculation to NRC on May 7, 2009 (ML091320366). The minimum COP margin is 3.5 feet with all drywell coolers in service and, therefore, operator action is not required to terminate drywell coolers to maintain containment pressure. However, termination of drywell cooling is desirable because it increases NPSH margin and since during an Appendix R event, the operation of the drywell coolers is not important to plant safety. Therefore, TVA plans to continue to secure drywell cooling in the Appendix R safe shutdown procedures. The NPSH/COP analysis results with and without drywell blowers operating are shown in the table above.

ACRS Recommendation 5

The staff review guidance in the current Standard Review Plan (SRP)[Ref. 4] should be revised to state that, if COP credit is granted to a plant based on risk information, all subsequent licensing applications involving COP credit at that plant should also include risk information.

BFN EPU Comparison with ACRS Recommendation 5

This recommendation is applicable to future licensing actions after EPU and is not part of TVA's review of the ACRS letter report.

ENCLOSURE 2

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3

TECHNICAL SPECIFICATIONS (TS) CHANGES TS-431 AND TS-418
EXTENDED POWER UPRATE (EPU)

RESPONSE TO NOVEMBER 10, 2008 ACRS LETTER
CONCERNS REGARDING CONTAINMENT OVERPRESSURE (COP) CREDIT FOR BFN EPU

For background on the Advisory Committee on Reactor Safeguards (ACRS) committee questions in the November 10, 2008, letter (ADAMs Accession No. ML082971024), included next is a brief submittal history on the BFN alternative fire analysis and the ACRS discussion section from the subject November 10 letter.

BFN Alternative Fire Analysis Submittal History

To address the risk of needing COP for fires, TVA performed an alternative fire analysis, which was submitted to NRC on November 15, 2007 (ML073230348). The alternative fire analysis was based on more realistic determinations of the likelihood of fire events of a magnitude necessary to cause damage similar to that assumed in the worst case Appendix R analysis and included an evaluation of the plant equipment and procedures that would remain available to safely shutdown of the plant for the various fire areas. As a continuation of the effort, a net positive suction head (NPSH) analysis for the 2 limiting fire areas was completed and submitted to NRC on June 12, 2008 (ML081700294).

ACRS Discussion from November 10, 2008 Letter

"In preliminary discussions of the Browns Ferry EPU, ACRS members expressed concerns over: (1) the crediting of high containment backpressure for long durations; (2) the need for operator actions that turn off automatic system responses; and (3) the low or no margins to pump cavitation even with the COP credit. The BFN Appendix R NPSH calculations result in low margins despite high COP credit (e.g., 1.6 psi minimum margin) and the COP credit is needed for at least 69 hours. In addition, the calculation assumes that the drywell coolers would be turned off no longer than 2 hours after the start of the fire in order to maximize the available containment pressure. The ACRS members suggested that TVA perform a fire risk analysis to demonstrate that the risk associated with the COP credit is low. In lieu of the fire risk analysis, TVA elected to perform an alternative fire analysis to show that a less prescriptive, but still conservative, fire hazard deterministic analysis that accounts for damage in identified fire areas would yield lower COP credit and duration.

On July 10, 2008, TVA briefed the ACRS on its COP alternative analyses. The briefing was supported by a June 12, 2008, submittal. During the briefing, the members raised several questions. In addition, in their review of the documents supporting the briefing, the members identified a need for additional information in order to be able to assess the adequacy of the alternative analysis."

Following are the specific ACRS questions from the November 10, 2008, letter on the BFN alternative fire analysis and on other COP topics along with TVA responses. These TVA responses are being provided to aid in the review of BFN's EPU application. Question number 1 was directed to the staff and is omitted below.

ACRS Questions

2) Clarification of the Alternate Analysis July 10, 2008, Presentation

(RAI APLA-35/37 of the November 15, 2007, RAI responses - Round 6)

a) *Specify the balance of plant equipment assumed to be available during the scenario. Are there any limitations to the equipment availability for the duration of the event that would affect the mitigating systems?*

TVA Response

For the 2 limiting fire areas in the alternative analysis which were determined to require COP (fire areas 4 and 9 as identified in TVA's November 15, 2007, submittal), 3 trains of balance-of-plant (BOP) equipment would be readily available to maintain reactor water level. The available BOP equipment includes the main condenser hotwell, which is the reactor water make-up inventory source, 3 condensate pumps, 3 condensate booster pumps, and the startup feedwater bypass valve along with their associated controls and power supplies. A single train of BOP has excess capacity to provide reactor make-up water and maintenance of condenser vacuum is not required for BOP equipment operation. Availability of the equipment depends on offsite power remaining available to the BOP electrical switchgear. Offsite power is assumed to be lost in the licensing basis Appendix R analysis, but is available in the alternative fire analysis.

b) *Describe how the systems and equipment (RHR & BOP) will be aligned to support the core and suppression pool cooling. Are these alignments included in the plant procedures for this event? What ensures that the appropriate personnel remain trained and qualified for this mode of operation?*

TVA Response

For the 2 limiting fire areas in the alternative fire analysis, BOP equipment would be used in a normal alignment to pump water from the condenser hotwell to the reactor to maintain reactor vessel coolant inventory and water level. Condensate pumps take suction from the condenser hotwell to supply suction to condensate booster pumps, which have the necessary pressure to supply make-up water to the reactor vessel through the feedwater system piping, startup level control valve, and feedwater lines at reactor pressures below approximately 500 pounds per square inch gage (psig). This BOP alignment would be used to maintain reactor water level in the normal range, which ensures core cooling. The

Residual Heat Removal (RHR) system would be aligned in the suppression pool cooling mode of operation for containment cooling. This alignment is a standard mode of RHR operation. In the alternative fire analysis, the controlling plant procedures are the plant Emergency Operating Instructions (EOIs). The EOI's either contain specific system alignments or specify the use of other operating instructions which do so. Use of EOIs is an integral part of the initial and continuing operator training program and operators routinely drill on EOI use during simulator training.

c) *For the alternate fire analysis presented to the ACRS, was a reactor core cooling analysis performed or were the reactor core conditions evaluated without reanalysis?*

<u>TVA Response</u>

In the alternative fire analysis, no high pressure injection systems are available in the 2 limiting fire areas. Therefore, the reactor must be manually depressurized using main steam safety relief valves (SRVs) to allow low pressure systems and BOP to inject to the vessel, which restores and maintains reactor water level. The rapid reduction in reactor pressure is conducted in accordance with the EOIs and is commonly referred to as emergency depressurization in the syntax of the symptom-based EOIs. The BFN EOI procedures are based on Boiling Water Reactor Owners Group Emergency Procedure Guidelines/Severe Accident Guidelines Appendix C and its supporting technical analyses, which ensures that peak clad temperature does not exceed 1500° F during the emergency depressurization operation. Since the fuel clad performance criteria for Appendix R (1500° F) is the same as that used in the basis for EOI emergency depressurization operations, it was unnecessary to perform a plant-specific reactor core cooling reanalysis.

d) *For the fire hazard analyses, would any fire requiring COP result in a LOOP? Since BOP systems depend on off site power, could a fire in areas 04 and/or 09 cause LOOP?*

<u>TVA Response</u>

In TVA's November 15, 2007, fire area evaluation submittal, 2 fire areas, 4 and 9, out of 39 total fire areas were identified as needing COP. In these 2 fire areas, the supporting analysis determined that offsite power would be available (i.e., no mechanistic means existed for a fire in either fire area to cause a Loss-of-Offsite-Power (LOOP)) to the BOP equipment.

e) *Identify any key parameters, inputs, and assumptions in the analysis that differ from the licensing calculations. Compare the values and assumptions used and justify the differences.*

<u>TVA Response</u>

The EPU Appendix R licensing basis NPSH/COP calculations, which included inputs and assumptions, were submitted to NRC on August 31, 2006 (ML062510371). A listing of the key input parameters/assumptions for the licensing basis analysis was also included in Table 1 of the June 12, 2008, submittal. In the alternative fire analysis NPSH/COP calculation, several of the Appendix R licensing basis parameters were relaxed or changed to more realistic values as shown in Table 2 of the June 12 submittal. The table below updates Table 2 from the June 12 submittal with additional explanation and justification of the differences in the Basis for Change column.

Changes in Inputs and Parameters for Limiting Fire Areas NPSH Basis Analysis

Parameter	Licensing Basis Value	Relaxed Analysis Value	Basis for change
4. initial suppression pool volume	122,940 cubic feet (minimum TS level)	123,855 cubic feet	Based on pool volume >95% confidence level from historical data
7. initial drywell pressure	15.5 psia	15.9 psia	Increased to match assumptions in original General Electric tasks reports for Appendix R
15. RHR heat exchanger K value	227 BTU/sec-°F	241 BTU/sec-°F (based on realistic fouling factor)	Based on a realistic fouling factor of 0.0020 vs. 0.0025 and maximum number of tubes plugged (1.5%). This is more representative of RHR heat exchangers.
17. RHR Mode of Operation	9400 gpm in LPCI mode until reactor depressurization, then 6000 gpm in Alternate Shutdown Cooling for heat removal.	7,000 gpm (EOI minimum suppression pool cooling flow rate for single pump)	In the alternative analysis, RHR is in suppression pool cooling mode. For the containment cooling analysis, the low end (7000 gpm) of the EOI operating restrictions is used.
18. drywell coolers in service	10 for first 2 hours, then coolers isolated	drywell coolers on throughout the event	Conservative scenario assumption
22. RHR pump heat addition	2,000 horsepower	1,600 horsepower	Corresponds to above 7000 gpm flow rate
23. RHR pump required NPSH (NPSHr)	Time-stepped value (minimum 21 feet, maximum 30 feet)	17 feet continuous	Corresponds to 3% NPSHr curves provided by Sulzer

Abbreviations
psia = pounds per square inch absolute
°F = degrees Fahrenheit
BTU/sec-°F = British Thermal Units/second - degree Fahrenheit
gpm = gallons per minute

f) *On Page E-4, TVA states that they have identified minor changes to procedures that will be made in order to improve the response to the fire event. What are these minor procedural changes? Would these procedural changes affect the Appendix R safe-shutdown instruction (SSI) or the Units' EOPs?*

TVA Response

Revisions to the SSIs were identified and implemented, which provided symptom-based entry conditions for declaring an Appendix R fire and executing the SSIs. These changes did not affect how the fire safe shutdown is conducted once an Appendix R fire was declared and the SSIs entered. There were no procedure changes affecting EOIs. The SSI revisions were subsequently deleted after NRC inspectors raised concerns that entry into the SSIs, when required, could be delayed by the new entry conditions.

g) *The following questions relate to the Appendix R analyses:*

i) *Is LOOP assumed for this event? If so, are the drywell coolers available for the first two hours of the event as assumed in the Appendix R analysis?*

TVA Response

In the Appendix R licensing basis event, LOOP is assumed at time zero of the fire scenario. A LOOP will not result in loss of all drywell coolers. Therefore, in the Appendix R licensing basis analysis, the drywell coolers were assumed to be in service for the first 2 hours (until terminated by operator action). This is a conservative assumption.

ii) *Provide discussions on how the staff confirms that the operator actions specified in the procedures and the operator trainings are consistent with the mitigation actions assumed in the analyses. For example, explain how the drywell coolers (within 2 hours of the start of the event) would be implemented in the SSI, EOP or other procedures.*

TVA Response

Drywell cooling is terminated in the SSIs by tripping or isolating the Reactor Building Closed Cooling Water (RBCCW) system, which supplies cooling water to the drywell coolers. The RBCCW pumps are stopped using the main control room hand switches or by tripping breakers/electrical boards that supply power to the RBBCW pumps. In a few instances, the RBCCW discharge valve is closed using the main control room hand switch. The subject SSI procedure revisions were validated in accordance with the BFN fire protection program, which ensures that the actions are feasible and can be accomplished within the specified 2 hour time limit. The SSI procedure steps to terminate drywell cooling involve simple switch operations that are similar to other manual actions carried out in the control room and from electrical board rooms in the SSIs. No special operator training needs were identified past standard operator training on SSI use. The instructions for terminating drywell cooling are contained wholly within the SSIs and no changes to the EOIs or other procedures were required.

The licensing basis Appendix R calculations have since been revised and show that the containment pressure will remain greater than the NPSHr for the RHR pump even with the drywell coolers in operation for the duration of the fire event. TVA submitted the revised NPSH analysis and calculations to NRC on May 7, 2009 (ML09132036). Therefore, it is not essential that the drywell coolers be secured to maintain adequate NPSH.

iii) *For the different fire scenarios, are there any conditions that could result in the drywell coolers not being turned off or being restarted after being initially turned off? If this is feasible, explain the specifics (e.g., operator actions) of each fire scenario that would be implemented in procedures.*

TVA Response

The procedural means for terminating drywell cooler operation in the SSIs is described in the previous response immediately above. Once these SSI steps are completed, it would take manual operator action to put the coolers back in service. This would not be permitted until the emergency was over and plant management authorized exit from the SSIs.

3) Pump Performance Data

In determining the required NPSH for given flow conditions, the pump vendor establishes required minimum NPSH values that correspond to operation at some degree of cavitation corresponding to 1% or 3% head loss.

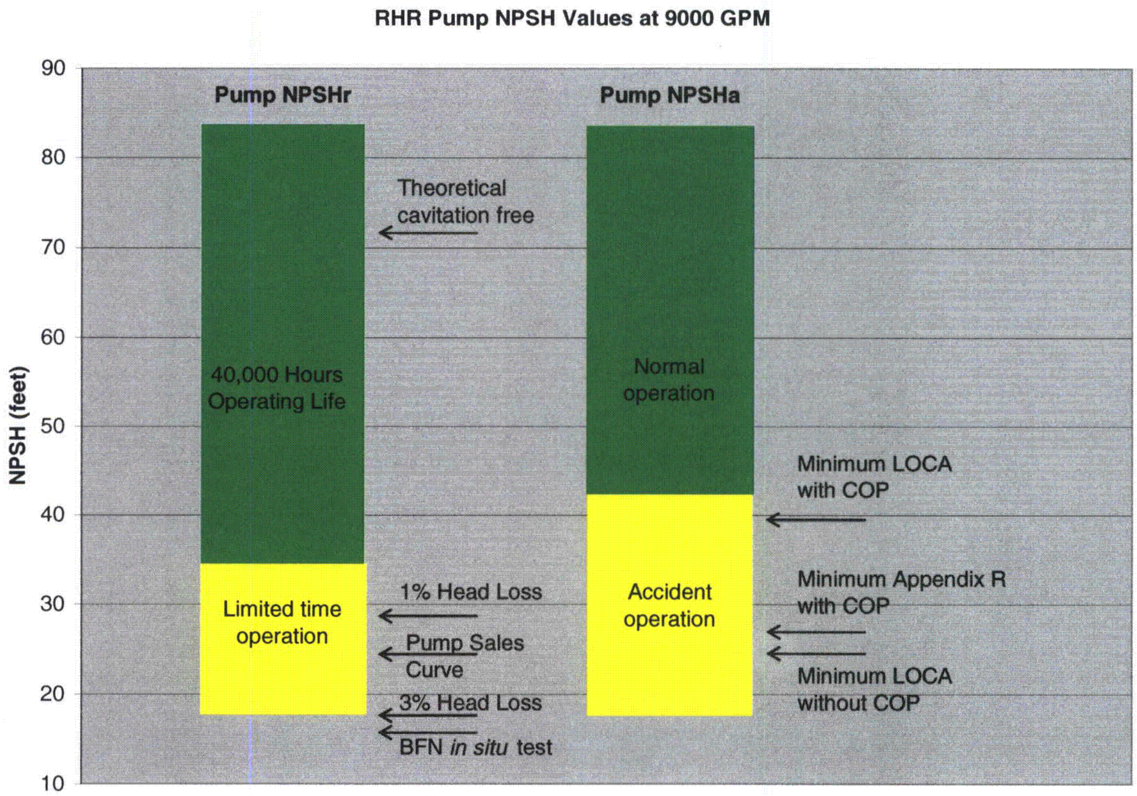
a) *For Browns Ferry RHR and CS pumps, explain if the 3% head loss was always used in determining the required NPSH or was the 1% criteria initially used for the Browns Ferry pump performance evaluation.*

TVA Response

In the past (prior to EPU), the NPSH/COP calculations used NPSHr values that were based on the original vendor performance testing conducted on each of BFN pumps commonly called the sales curves. The original RHR pump sales curve NPSHr values are approximately midway between the 1% and 3% head loss curves shown in Curve 2 of the BFN Sulzer report. For CS, the NPSHr values were also based on the CS pump sales curves and are greater than the 1% head loss curves at mid-range flows and approximately midway between the 1% and 3% head loss curves at high flows. A copy of the Sulzer report was included in the June 12, 2008, submittal.

Beginning in 2006, the EPU NPSH/COP analyses were performed with the pump vendor developed NPSHr values based on operation at reduced NPSH values for limited periods of operating time. These NPSH values are given in Curve 3 and 6 of the Sulzer report and are lower than the pump sales curves for short-term operating durations. TVA submitted the NPSH/COP calculations that used the 8000-hour NPSH values in the previously referenced August 31, 2006, calculations submittal.

In the alternative fire analysis NPSH calculation results that were provided in the June 12, 2008, submittal and later in the revised Appendix R licensing basis analysis results submitted on March 12, 2009 (ML090720951), TVA started using the 3% NPSHr values from Curve 2 of the Sulzer report for the RHR pumps. ANSI/HI 9.6.1-1998, "Centrifugal and Vertical Pumps for NPSH Margin" defines NPSHr as the NPSH that will cause total head to be reduced by 3%. Use of the 3% curves provided a reduction of several feet in NPSHr and lessened the magnitude and duration of required COP. The below figure illustrates the NPSH values that have been used to evaluate RHR pumps in relationship to pump operation.



b) *The SULZER report states that the original test records were lost or misplaced. During the briefing, it was stated that the raw data for the required NPSH are available. These statements appear to be conflicting. Please, clarify.*

TVA Response

The Sulzer report is referring to original paper copies of the vendor pump test records. Copy machine copies of the records were available and used in the development of the NPSH curves.

c) *For the ST-LOCA, the vendor states that the scenario falls outside the established operating recommendations for the RHR pumps. However, based on some test data, the vendor concludes that although vibrations and noise may occur due to surges and cavitation, the pumps should be able to continue to function. In these tests, the suction pressures were varied so that the pumps would cavitate. At what temperature were these tests conducted? Would the test results be different if the suction temperature of the flow is also increased in order to make the test more prototypic?*

d) *For the Appendix R scenarios, the vendor states that: "The minimum required NPSH value that will allow the subject pumps to successfully operate at 9000 gpm for 70 hours is 17 feet. At this NPSHa, level there is little to no theoretical NPSH margin remaining. The RHR pump, subject to these conditions will likely exhibit signs of cavitation; however it will continue to function throughout the event." Similar to the assessment for the ST LOCA, were the tests conducted at prototypic temperatures?*

TVA Response to 3.c and 3.d

The pump vendor performance tests were conducted at temperatures from ambient up to approximately 100° F. NPSHr reduces with increasing water temperature as shown in ANS standard, ANSI/H1-1.5-1994, "Centrifugal Pumps", published by the Hydraulic Institute (HI). Therefore, conducting the NPSH tests at lower temperatures yields conservative NPSHr results.

e) *In the SULZER report, the vendor combines empirical data and calculations to develop the NPSHr curves for different pumps and flow rate. In essence, the operability of the pumps and the flow rates for both Appendix R and the ST-LOCA rely on the accuracy of the SULZER tests. In addition, the generated NPSHr do not include or quantify uncertainties, which may affect the calculated margins in all events. Have these uncertainties been quantified? What are the uncertainties in the NPSHr values at different flow rates?*

TVA Response

NPSHr is used for evaluation of pump performance considering both 1) pump functionality - will the pump produce sufficient flow and pressure to perform its function; and 2) service life - will the pump operate long enough to complete its function. The subject vendor tests are used to demonstrate function at reduced NPSH whereas industry experience and analysis are used to determine the effect of NPSH on service life.

Pump Functionality

The ANSI/HI 9.6.1-1998 definition of NPSHr (based on 3% head loss) establishes the criteria for functionality. Regulatory Guide 1.82 Revision 3, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident," November 2003, includes the same definition. The capability of the RHR pumps to perform their function with an NPSH of 17 feet at 9000 gpm was demonstrated by vendor tests. There is additional margin between this 3% NPSHr value and the NPSH at which the pump would begin to malfunction as confirmed by *in situ* tests performed in 1976 for the 3C RHR pump at suppressed suction pressures. The pump operated satisfactorily at a NPSH value of 15 feet. A description of the 1976 *in situ* pump tests along with the test results were submitted to NRC on May 21 and July 21, 1976. Additionally, as discussed in the above response to item 3.c/d, NPSHr improves with increasing water temperature. Using Figure 1.57, "NPSHr Reduction for Pumps Handling Hydrocarbon Liquids and High-Temperature Water," from ANSI/H1-1.5-1994, yields about 1 1/2 feet of NPSHr improvement at temperatures of 220° F compared to the 100° F test conditions. For conservatism, the TVA NPSH/COP calculations ignore the NPSHr temperature credit. Combining the margin observed in the *in situ* pump tests (17 feet minus 15 feet = 2 feet) and the 1 1/2 feet NPSHr temperature correction, it is seen that there is approximately 3 1/2 feet of conservatism in NPSHr that is not credited in the calculations. This conservatism would easily bound uncertainties associated with testing or nominal variations in the operating characteristics of individual pumps.

Service life

In the Sulzer report, Sulzer also provided a "Recommended" NPSH curve (shown on Curve 3 and Curve 5) for normal operation to achieve the long-term service life for the RHR and CS pumps, which is 40,000 hours of operation. The service life NPSHr curves provided by Sulzer are based on testing and on operating experience. The limiting component in the pump is the impeller, which will gradually wear from erosion over time. Impeller failure due to insufficient NPSH is gradual and will present as flow reduction after sufficient damage occurs. For the RHR pumps, the vendor recommends a minimum NPSHr of about 33 feet to achieve this 40,000 hour service life. Sulzer also provided NPSH curves based on 8000 hours of service life, which included reduced NPSHr values for limited time duration operations. These are shown on Curves 4 and 6 of the Sulzer report and are used in the LOCA NPSH/COP calculations.

For Appendix R, Sulzer also provided an evaluation which assumed 70 hours of continuous RHR pump operation with the NPSHa equal to the 3% NPSHr value of 17 feet at the 9000 gpm flow used in the licensing analysis. That is, the vendor evaluation assumed there was no additional NPSH above NPSHr for a 70 hour duration. This Sulzer evaluation was provided in Appendix C of the Sulzer report that was attached to the June 12, 2008, submittal, in which they concluded that in these conditions, the pump would likely exhibit signs of cavitation; however, it would continue to function. TVA's March 12, 2009, submittal provided the results of the licensing basis Appendix R NPSH/COP analysis, which used the 3% NPSHr of 17 feet. With COP credit, there is substantial NPSH margin throughout the event. The minimum NPSH margin was calculated to be 4.1 psi (9.5 feet) is seen early in the event and increases continuously thereafter to 13 feet at peak suppression pool temperature and is approximately 25 feet at 70 hours. The duration where some COP is needed decreased from 69 hours to 27.8 hours. The Sulzer RHR pump evaluation, which assumed no NPSH margin for 70 hours of operation, is very conservative with respect to the event analysis.

Testing Standards

Methods for pump testing including determination of NPSHr values are described in HI standards (currently ANSI/HI 1.6-2000, "Centrifugal Pump Tests"), which includes requirements for accuracy of test equipment. The original BFN testing referenced in the Sulzer report was in compliance with ASME power test code 8.2 and HI standards; gages and other instruments were calibrated in accordance with these governing specifications. Thus, testing accuracies and uncertainties are addressed by use of industry standard test methods.

f) *Data from all the pumps manufactured by the vendor that are similar to the RHR and core spray pumps used in Browns Ferry have been averaged to develop average characteristic curves for the pumps. In both the Appendix R and the more realistic fire scenario only one RHR pump will be in service. The characteristic curve of this pump could be different from the average behavior of all pumps. Considering the 1.6 psi margin for Appendix R calculations, the accuracy of the characteristic curves becomes important. Are the uncertainties in the characteristic curves small enough to assure that there actually is margin for the Appendix R scenario?*

TVA Response

Each BFN pump was supplied with its own characteristic curve, which provided documentation of the contractual witness test. One witnessed performance curve (customer curve 27872) for a BFN RHR pump was included in the Sulzer report as an example. The Sulzer report includes a characteristic averaged head flow curve (Sulzer Report Curve 1), which was derived from TVA's RHR pumps only; no other test data was included in the average. The head flow curves from the original pump vendor manuals serve as input to TVA's NPSHa calculation, which contains a system performance curve for modeling purposes. Since the Appendix R NPSH/COP calculations are based on an assumed RHR flow rate of 9000 gpm, which any of the RHR pumps can easily achieve, nominal performance variations among pumps are not significant in the NPSH calculations.

g) *The cavitation free required NPSH is 75.3 ft for flow of 12,000 gpm. The SULZER recommended required NPSH for 12,000 GPM, for 40,000 hours is 99.8 ft. Explain the discrepancies between the lower cavitation free NPSH and the recommended NPSH, which does not preclude cavitation. There is a similar discrepancy for the core spray pumps at 4500 gpm.*

TVA Response

The NPSHr curves in the Sulzer report are derived from the Lobanoff and Ross pump design book[1] and are theoretical curves (not based on test results). The theory uses a prediction of head degradation as the basis for its analysis. The "cavitation free" calculations are presented in the Sulzer report. The Sulzer "Recommended" NPSH is derived by analysis based on head loss and bubble formation with the realization that bubble formation (cavitation) occurs before head degradation is even measurable. This effect increases as flows diverge from the pumps' Best Efficiency Point (BEP) and so the Sulzer "Recommended" curve will eventually cross the Lobanoff and Ross pump design "cavitation free" curves at high flows. BEP is 8600 gpm for the RHR pumps and 3000 gpm for the CS pumps. It is important to recognize that the Sulzer recommended NPSH curves are based on ensuring long-term pump operation (40,000 hour service intervals). For the purposes of evaluating pump performance for highly unlikely, limited duration events such as LOCA and Appendix R, use of NPSHr values based on a limited duration operation is more appropriate.

h) *The draft staff SER justifies the operation of the RHR pumps for a short-duration under degraded conditions, in part, based on sensitivity analyses that showed with lower LPCI flows (11,000 gpm) and drywell humidity (50%), the margin increases. Explain the reasons for the difference between the maximum LPCI flow used in the NPSH calculations (11,000 gpm) for the ST-LOCA and the manufacturers design runout flow 11,500 gpm)*

TVA Response

The August 31, 2006 submittal NPSH/COP calculations for short-term LOCA for 2 RHR pumps, broken recirculation loop case, assumed a RHR flow value of 11,500 gpm with a 500 gpm margin. When the head losses from the remaining piping and components in the broken loop are calculated, the RHR flow would actually be 11,000 gpm. On March 12, 2009, TVA submitted revised calculation results for short-term LOCA, broken loop, with the RHR flow reduced to 11,000 gpm, which results in a lower RHR pump NPSHr. The initial drywell relative humidity was also reduced to 50% to be more realistic of the bounding value.

4) Inhibiting Automatic Actuation of Containment Coolers

For Browns Ferry Appendix R, the drywell coolers are assumed to be turned off after 2 hours into the event in order to maximize the containment pressure. Without turning off the drywell coolers, the required NPSH for the sole RHR pump would exceed the available NPSH for a significant amount of time. The drywell coolers are considered non-safety systems but are relied upon in meeting the TS containment pressure and temperature. These TS containment P/T values are assumed as initial conditions in the containment analyses. The following questions relate to the turning automatic systems off.

[1] Labanoff, V. S. and Ross, R.R, Centrifugal Pumps, Design and Application, Second Edition, 1995

a) *Operator actions requiring turning off automatic systems under high temperature and pressure containment environment are counter-intuitive in terms of containment integrity. Justify why counter-intuitive operator actions under a high PT conditions are acceptable, in the context of industry lessons- learned experience. In addition, provide evaluation of the NRC lessons-learned assessment and actions in reference to inhibiting automatic although non-safety containment pressure reduction features that would then result in an increase in containment pressure. The issue is not whether the specific Appendix R scenario would threaten containment integrity but rather implementing operator actions that would counter the overall containment integrity objective of reducing the pressure.*

TVA Response

During normal plant operation, the drywell airspace is cooled by the drywell cooling system. The major contributors to the drywell heat load are the reactor vessel and its attached piping, and the reactor recirculation pumps, which are located in the drywell. Although it is probable that some coolers would be lost due to the fire or as a result of electrical board alignments for execution of the SSIs, in the Appendix R analysis, all ten drywell coolers are assumed to be in service for 2 hours for analytic conservatism.

During an Appendix R event, the reactor recirculation pumps are secured and the SSIs will instruct the operators to rapidly depressurize at 20 minutes to allow RHR to inject to the vessel from the suppression pool. Depressurizing the reactor from rated temperature and pressure will result in a rapid reduction in the reactor vessel temperature from about 525° F to a much lower temperature since in Appendix R alternate shutdown cooling mode, suppression pool water is injected to the vessel and recirculates to the suppression pool via the main steam SRVs. The continued operation of drywell coolers with the 2 predominant heat sources (reactor recirculation pumps and vessel/piping at rated temperature) removed will result in a rapid cooling of the drywell airspace. This decrease in drywell airspace temperature would ultimately have an adverse affect on available containment pressure to support RHR pump NPSH. Therefore, in the SSIs, the operators are instructed to terminate drywell cooling within 2 hours of event start. Additional detail is provided in the responses to items 2.g.i., 2.g.ii, and 2.g.iii above. As pointed out in those responses, the SSI procedure steps to remove drywell coolers from service are similar to typical SSI steps. Once in SSIs, verbatim execution of the SSIs is required and operators are not provided leeway to deviate.

As discussed in the item 2.g.iii response, the Appendix R NPSH calculations have been revised to consider the case where the drywell coolers are not removed from service at 2 hours, but rather continue to operate for the duration of the event. With all drywell coolers operating, the drywell airspace temperature decreases from the assumed initial temperature (150° F) to approximately 110° F following the reactor depressurization and will trend lower in the long term as the suppression pool is cooled. If the drywell cooler operation is terminated at 2 hours, the drywell temperature will begin to increase and is calculated to peak at about 208° F. The increase is drywell temperature is ultimately limited by the suppression pool temperature since as noted above, in Appendix R alternate shutdown cooling mode, suppression pool water is being directly injected to the vessel. Although the drywell temperature increase to 208° F is higher than the 150° F maximum allowed drywell air space temperature during normal power operation, it remains well below the containment design limit of 281° F. In the long term, the drywell air space temperature will decrease as the suppression pool is cooled.

In the revised Appendix R NPSH calculations submitted on May 7, 2009, the results show that there is sufficient NPSHa with all drywell coolers operating throughout the event. However, since the drywell coolers do not provide an important to plant safety function during an Appendix R event, termination of drywell cooling is desirable because the action increases available NPSH margin. Therefore, TVA plans to continue to secure drywell cooling in the BFN Appendix R SSIs.

5) Impact of High Temperature Environment on Pumps and Penetration Seals

a) *For Appendix R, demonstrate that the high P/T environment would not adversely affect the systems and components required to mitigate the event, such as SRV tailpipes and neutron monitoring systems.*

b) *Evaluate the impact of prolonged exposure to high pressure/temperatures and radiation field on the seals and penetrations. For any adverse impact, evaluate how it affects the availability of containment overpressure and the operability of the equipment relied upon to mitigate the event such as pumps.*

TVA Response to 5.a and 5.b

There is no increase in radiation levels in the Appendix R events. Termination of the drywell cooling results in a peak drywell temperature of 208.6° F after which the drywell air space temperature steadily decreases as the suppression pool temperature decreases. This peak temperature is well below the containment design limit of 281° F and far below the peak drywell air temperatures of 336° F used for equipment qualification, including penetrations, in the pipe break analyses.

In the drywell, the only equipment credited in the Appendix R safe shutdown analysis is associated with the SRVs, the High Pressure Coolant Injection (HPCI) system, and Reactor Core Isolation Cooling (RCIC). The associated SRV components located in the drywell are the solenoid valves, power cables, connectors, and cable splices. Environmental qualification (EQ) in accordance with 10CFR50.49 is not required for Appendix R, but typical EQ test reports used for LOCA qualification were reviewed with respect to the air space temperature predicted in the Appendix R drywell coolers off case. SRV solenoids were tested for 100 days at a minimum of 213° F; the power cables were tested for 100 days at a minimum of 220° F; connectors were tested for 30 days at a minimum of 265° F, and splices were tested at a minimum of 210° F for 30 days. In the safe shutdown analysis, HPCI and RCIC operate for a brief period of time early in the analysis. HPCI/RCIC components were not reviewed since they are removed from operation prior to any increase in drywell temperature.

ENCLOSURE 3

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3

TECHNICAL SPECIFICATIONS (TS) CHANGES TS-431 AND TS-418
EXTENDED POWER UPRATE (EPU)

COMPARISON OF BFN EPU LOCA CONTAINMENT OVERPRESSURE (COP) CREDIT WITH OTHER EPU BWRs

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Below is a comparison of EPU COP requirements between BFN and several Boiling Water Reactors (BWRs) of similar design vintage for the Loss-of-Coolant Accident (LOCA) analyses. The required COP was obtained from the NRC EPU Safety Evaluations.

BWR EPU LOCA COP Comparison
(*From NRC EPU Safety Evaluation)

Plant	EPU Increase (%)	EPU Increase (MWt)	EPU Approval Date	Peak Torus Temperature (°F)	Required* COP (psi)	Duration
A	15.3	248	11/06/01	209.2	5.3	Not specified
B	17	430	12/21/01	196	9.5	~ 56 hours
C	17.8	446	12/21/01	199	8	~ 56 hours
D	15	365	05/31/02	207.7	5	~ 20 hours
E	20	319	03/02/06	194.7	5.06	~ 55 hours
Browns Ferry	14.3	494	-	186.6	3.1	~ 23 hours

Abbreviations

MWt = megawatts thermal
psi = pounds per square inch
°F = degrees Fahrenheit