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

CNL-16-073

April 22, 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 12, 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 April 11, 2016 (ML 16097A296)

By the Reference 1 letter, 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. During their technical review of the LAR, the Nuclear Regulatory Commission (NRC) identified the need for additional information. The Reference 2 letter provided NRC Requests for Additional Information (RAI) related to human factors. The due date for the responses to the NRC RAIs provided by the Reference 2 letter is April 22, 2016. The enclosure to this letter provides the responses to the RAIs included in the Reference 2 letter.

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 22nd day of April 2016.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosure: Responses to NRC Requests for Additional Information APHB-RAI 1, APHB-RAI 2, APHB-RAI 3, and APHB-RAI 4

cc:

NRC Regional Administrator - Region II
NRC Senior Resident Inspector - Browns Ferry Nuclear Plant
State Health Officer, Alabama Department of Public Health

ENCLOSURE

Responses to NRC Requests for Additional Information
APHB-RAI 1, APHB-RAI 2, APHB-RAI 3, and APHB-RAI 4

ENCLOSURE

APHB-RAI 1

Section 2.11.1.1 of Attachment 6 (NEDC-33860P, Revision 0), "Safety Analysis Report for Browns Ferry Nuclear Plant, Units 1, 2, and 3 Extended Power Uprate [EPU]," to the September 21, 2015, EPU submittal indicates that some procedures are not yet complete. For instance, page 2-509 indicates that at least 2 new procedures will be developed to support actions related to EPU. Review Standard for Extended Power Uprates (RS-001), Revision 0 (ADAMS Accession Number ML033640024), Section 2.11.1, Human Factors, references Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reactor] Edition (SRP) Chapter 13.5.2.1 which has a criterion asking that licensees describe schedules for completion of procedures. Please provide additional information clarifying the completion of all procedures needed to support EPU.

a. *When will all EPU related procedures be complete? Will all procedures be complete and available prior to validation activities?*

b. *Describe validation activities that will be conducted to determine if operators can accurately complete all time critical tasks within the time allowed by analysis.*

TVA Response:

a. All procedures required for the implementation of the Extended Power Uprate (EPU), will be implemented prior to the completion of the EPU implementation outage for that unit. The EPU implementation outages are as follows: Unit 3 in spring of 2018, Unit 1 in fall of 2018, and Unit 2 in spring of 2019. Procedure validation is part of the procedure change process. All EPU related procedures requiring validation will be made available in sufficient time to allow validation activities to be completed prior to the end of the implementation outage for the requiring unit.

b. Validation activities for time critical tasks:
The only time-critical operator action resulting from EPU implementation is the need to crosstie the Containment Atmosphere Dilution (CAD) system to the Drywell Control Air system during a Station Black Out (SBO) event. Analyses show that this crosstie must occur within two hours of receiving control room annunciator “MAIN STEAM RELIEF VLV AIR ACCUM PRESS LOW” to ensure sufficient air supply to the main steam relief valves. The guidance for performing the crosstie is the Emergency Operating Instruction (EOI) procedure EOI Appendix-8G, “Crosstie CAD to Drywell Control Air.” Previous time validation has shown that the crosstie can be completed in less than 10 minutes. The crosstie is performed in the control room and may be performed from either Unit 1 or Unit 3 (Unit 1 and Unit 2 share a common control room). The crosstie lines up the CAD system to the Drywell Control Air system on all three units. TVA will perform additional time validation, using the site simulator with three different operating crews, that during SBO scenarios, performance of this 10-minute task can be accomplished within two hours of the annunciator being received. These time validations will be completed prior to EPU implementation on the first unit (Unit 3 in spring 2018).

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[1] Attachment 7 contains a non-proprietary version of Attachment 6.

ENCLOSURE

APHB-RAI 2

RS-001 Section 2.11.1, "Human Factors," Question 2 describes the properties of operator actions that should be described in an EPU submittal. Attachment 6, Section 2.11.1.2 contains information regarding changes to operator actions sensitive to power uprate. Additional information is necessary to clarify the nature of operator actions and the methods used to ensure that all risk-important operator actions can be completed as described in the submittal.

a. *The following operator manual action: "Crosstie of the Containment Atmospheric Dilution system to the Drywell Control Air System" (described in LAR Attachment 6, Section 2.11.1.2.1) identified this action as a time sensitive operator action. NUREG-0711, "Human Factors Engineering Program Review Model," indicates that important human actions should be verified through a human factors verification and validation process.*

   Provide details of validation activities that will be performed that provide assurance that the task can be completed as designed.

b. *Attachment 6, Section 2.11.1.2.2 describes the broad category of Fire Safe Shutdown Events. It does describe in detail any new or changed operator actions as a result of the proposed EPU.*

   Attachment 44 of the EPU LAR, Section 5.2 identifies five fire scenario-related human failure events that are major contributors to change in plant risk, as the result of the proposed EPU: (1) HFFA0002RPV_LVL: Operator failure to maintain the reactor pressure vessel level using the condensate system for fire scenarios that lead to a general transient scream (no main control room (MCR) abandonment); (2) HFFA0SD_RCIC: Operator failure to start Reactor Core Isolation Cooling from remote shutdown panel for fire scenarios that lead to MCR abandonment; (3) HFFA0268480CRSTIE: Operator failure to isolate/de-energize the 480V board from fire impacts and repower it from an alternate source/supple for fire scenarios that lead to a general transient scream (no MCR abandonment); (4) HFFA0SUPPHPI2: Operator failure to initiate supplemental injection (using the proposed emergency high pressure makeup pump) within 35 minutes for fire scenarios that lead to a general transient scram (no MCR abandonment); (5) HFFA0RHRCS_LPP: Operator failure to bypass the low pressure coolant injection valve low pressure permissive interlock when the low pressure permissive is failed due to fire impact for fire scenarios that lead to a general transient scram (no MCR abandonment).

   Provide additional information that clarifies how the operator actions associated with the HFEs described above were addressed by the HFE program, consistent with the process described in NUREG-0711, Section 7 – Treatment of Important Human Actions. Further, describe any planned or performed validation activities that will provide (or have provided) evidence that those operator actions can be completed feasibly and reliably, within the time available under EPU conditions.

   Note that the response to this request for additional information (RAI) may overlap with the RAIs submitted by letter dated February 25, 2016 (ADAMS Accession Number ML16041A022). The licensee may reference the responses to those RAIs or other docketed material in your response.

c. *Attachment 44, "Probabilistic Risk Assessment [PRA]," of the EPU LAR, Section 5.1 discusses Internal Events PRA results. For reactor transients involving successful reactor scram (e.g., loss of feedwater, loss of condenser vacuum, turbine trip) with no breaks outside containment or stuck open relief valves, operator fails to control reactor pressure [vessel] (RPV) level with high pressure injection systems combined with operator fails to depressurize RPV when water level drops to top of active fuel. These operator actions are associated with accident sequences that involve loss of inventory makeup in which the reactor pressure remains high, and are major contributors to EPU internal events risk.*

Provide additional information that clarifies how the operator actions associated with the HFEs described above were addressed by the HFE program, consistent with the process described in NUREG-0711, Section 7, "Treatment of Important Human Actions." Further, describe any planned or performed validation activities that will provide (or have provided) evidence that those operator actions can be completed feasibly and reliably, within the time available under EPU conditions.

TVA Response:

a. The task to crosstie the CAD system to the Drywell Control Air System, described in the BFN EPU license amendment request (LAR) Attachment 6, Section 2.11.1.2.1, is not a new activity. This task currently exists in multiple locations within the emergency operating instructions (EOIs) and abnormal operating instructions (AOIs), including AOI-57-1A, Loss of Offsite Power (161 and 500 kV)/Station Blackout (SBO), Attachment 12. The task is accomplished by performing procedure EOI Appendix-8G, Crosstie CAD to Drywell Control Air. This implementing procedure was validated upon initial development (validation date was March 30, 2007) and during its most recent revision (validation date was February 16, 2015). The proposed revision described in BFN EPU LAR Attachment 6, Section 2.11.1.2.1 will include a reference to a time frame in which the activity is expected to be needed to be accomplished during an SBO. Note that the initiating cue to the control room operator to perform the task is receipt of control room annunciators "DRYWELL CONTROL AIR PRESS LOW" or "MAIN STEAM RELIEF VLV AIR ACCUM PRESS LOW." These cues will not change during EPU operation because EOIs and this AOI flowchart are symptom based. No changes will be made to the physical execution of the implementing procedure steps. No changes will be made to the control room indications or switches used to physically perform the task.

This task is routinely trained in the licensed operator continuing training program. The task was recently given as part of an operator exam "job performance measure (JPM)" in October 2015. In that exam, nine operators performed this JPM. The time to complete the task ranged from three to six minutes.

TVA will perform additional time validation, using the site simulator with three different operating crews, that during SBO scenarios, performance of this 10-minute task can be accomplished within two hours of the annunciator being received. These time validations will be completed prior to EPU implementation on the first unit (Unit 3 in spring 2018).

b. As noted in BFN EPU LAR Attachment 44, the fire risk model logic is the same for current license thermal power (CLTP) and EPU. Operator actions within the fire probabilistic risk assessment (FPRA) model were evaluated by performing human reliability analysis (HRA). As documented in Section 3.4, of Reference 1, Fire Risk Assessment, the FPRA model and associated operator actions were approved by the NRC. The underlying operator actions associated with these human failure events (HFEs), procedures used to perform the actions, and controls and indications available to the operators do not change at EPU. Also documented in Reference 1, Section 3.2, Nuclear Safety Capability Assessment Methods, is the requirement that new and revised procedures be validated and operators trained prior to implementation transition to National Fire Protection Association (NFPA) 805. These requirements are identified in Reference 1 as LAR Attachment S, Table S-3, Implementation Items 27, 28, 29, 30, 31, and 33. Because the physical performance of these actions do not change at EPU, the conditions under which the actions would be performed do not change, and the equipment, controls, and indications have not changed at EPU with respect to these actions, no additional human factor engineering consideration and no additional validation or verification is required. BFN relies upon the HRA performed for development of the fire risk model for the NFPA 805 license amendment.

Operators are trained and evaluated performing these tasks in the licensed operator initial and continuing training program. Validation that the tasks can be performed is inherent to the training, qualification and licensing of licensed control room operators.

c. The current BFN Probabilistic Risk Assessment (PRA) model of record used to support current plant operations conservatively uses EPU thermal hydraulic calculations and associated timings, and the two operator actions identified in this RAI were already identified as significant by TVA. That is, their significance was already known and is already inherently imbedded in the current training program. Both operator actions have been inherent to BFN EOIs since the EOIs inception. The operator actions to initiate high pressure injection and to depressurize the reactor pressure vessel (RPV) were analyzed at EPU conditions in the human reliability analysis (HRA).The HRA demonstrates the actions are feasible with more than adequate time available to recognize and recover from a failure to perform either action. As an integral part of BFN's operator training program, individual operator performance as well as crew performance is observed during training sessions and subsequently critiqued for deficiencies and opportunities to improve. Periodic operating exams are administered to licensed operators using approved simulator scenarios. Critical tasks associated with restoring and maintaining adequate core cooling (RPV inventory) are identified within various exam scenarios. All simulator exam scenarios are validated prior to administering. EPU will not change the controls and indications of the high pressure coolant injection (HPCI) or the reactor core isolation cooling (RCIC) systems in a manner that would affect the operator's ability to operate the systems. EPU will not change the controls and indications of the main steam safety relief valves (MSRVs). Because no changes will be made to the controls and indications of the HPCI, RCIC, or MSRV systems, and these operator actions are longstanding EOI actions that receive periodic operator training, and the actions' feasibility were demonstrated in the BFN PRA HRA, these tasks require no additional human factors engineering or task validation.

ENCLOSURE

Reference

1. Letter from NRC to TVA, “Browns Ferry Nuclear Plant, Units 1, 2, and 3 – Issuance of Amendments Regarding Transition to A Risk-Informed Performance-Based Fire Protection Program in Accordance With 10 CFR 50.48(c) (CAC Nos. MF1185, MF1186, and MF 1187),” dated October 28, 2015 (ML15212A796).

ENCLOSURE

APHB-RAI 3

Question 3 in Section 2.11.1, "Human Factors," of RS-001 states:

> *Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will be changed? What setpoints will be changed? How the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine that they could use the instruments reliably. (SRP Section 18.0)*

a. *Attachment 6, Section 2.11.1.3 "Changes to Control Room Controls, Displays and Alarms" provides a list of Human-System Interfaces (HSIs) that will be installed, changed, or removed to support this LAR. However, this list fails to describe the various human factors principles addressed in the criterion. Provide additional information regarding the changes listed in Section 2.11.1.3 of Attachment 6, for the items listed below, and for any other changed HSI:*

   (1) *Emergency High Pressure Makeup Pump controls will be installed as described in Bullet 1 of Section 2.11.1.3. However, there is no description of what the control will be (is it analog or digital, does it use a three-position switch, etc.). Is the design of the control consistent with other similar controls? Please describe the control and compare it to other similar controls. If it is different than other similar pump controls explain the difference as well as any safeguards used to prevent accidental operation.*

   (2) *Bullet 5 of Section 2.11.1.3, removed the Steam Jet Air Ejectors auto-start capability and replaced the HS-150/152 three-position switches with two-position switches. Are there any credible errors likely due to the different design of the switch? How credible errors will be prevented?*

   (3) *Section 2.11.1.3, Bullet 6 indicates that control switches that used to operator the Moisture Separator Drain Pumps are now used to operate the Moisture Separator Isolation Valves. There is currently no discussion that describes how the licensee intends to prevent operator confusion as a result of this change. What type of safeguards are being used to ensure that operators maintain situation awareness about what system is being used and are not following old habits.*

b. *The Technical Specification (TS) markups in Attachment 2,"Proposed Technical Specification Markups," include multiple changes that involve rescaling of various systems settings necessary to maintain acceptable safety margins. This typically involves decreasing various parameters slightly (usually by about 1-2 percent) to maintain acceptable safety margin. For instance, CONDITION B of Limiting Condition for Operation 3.7.5 had a REQUIRED ACTION: "Reduce THERMAL POWER TO <u><25%</u> RTP [rated thermal power]," whereas the revised version of this same REQUIRED ACTION states: "Reduce THERMAL POWER TO <u><23%</u> RTP." Simple fractions such as 1/4 are generally easy for operators to read off of various analog gauges. In some cases, it may be difficult or impossible for operators read the difference of 2% from* *existing displays (especially analog displays). Precise calculations are also more challenging using the updated values.*

(1) *Clarify how the updated values in the TSs translate into corresponding updated values in operating procedures and whether such updates may present potential challenges for operators. (For example, it may be difficult or impossible for operators to tell the difference of 2%, when reading the parameter value from an analog gauge).*

(2) *Describe any changes to the HSI that may need to be made, in connection with the TS changes (and the corresponding operating procedure changes) – including, but not limited to re-scaling of existing meters and gauges, changes to zone markings on meters, upgrades from analog to digital instruments, changes to setpoints, etc.*

TVA Response:

a.(1) The Design Change Notice (DCN) for the Emergency High Pressure Make-up (EHPM) Pump adds three control switches (EHPM pump, normal system flow control valve, and test line flow control valve) on both the EHPM panel insert in the main control room (MCR) and the new local panel and an additional control transfer switch on the local panel. All use standard pistol-grip rotary controls consistent with existing controls used for similar functions on the Browns Ferry Nuclear Plant (BFN) MCR panels. There are nine analog-format indicators, same style as existing indicators, added by the DCN to the MCR and local panels. The operators will be trained on these changes prior to implementation. These controls are only allowed to be manipulated by following approved station procedures. This requirement, coupled with approved labeling and an expectation for operators to use self-checking techniques when manipulating controls, will help prevent errors and accidental operation.

a.(2) This DCN has been installed on all three units since 2007. This DCN eliminated the condenser pressure inputs to the Steam Jet Air Ejector (SJAE)-A and SJAE-B auto-start circuits. A review of operating procedures, prior to implementing this DCN, showed that the SJAE-A and SJAE-B control switches were never placed in the AUTO position, which would have enabled the auto start circuit. As such, eliminating this function, by replacing the three-position control switches with two position switches, does not impact plant operation. This change reduces error probability by eliminating an unused switch position. The operators were trained on these changes prior to implementation. These switches are only allowed to be manipulated by following approved station procedures. This requirement, coupled with approved labeling and an expectation for operators to use self-checking techniques when manipulating controls, will help prevent errors and accidental operation.

a.(3) This DCN has been installed on all three units since 2007, and operators were trained on the changes prior to implementation. This DCN removed the moisture separator drain pumps (MSDPs) and re-purposed the pump's suction valves into system isolation valves. A new backfill valve, which injects condensate into the moisture separator drains to quench steam and ensure condensate flow to the condenser, was also added. In the control room, six pistol grip control switches for the MSDPs were removed. The new system operates to control level in the moisture separator drain tanks by using system pressure drop to move condensate toward the main condenser. The control switches for the MSDP suction valves were relabeled as the moisture separator isolation valves. Credible errors have been prevented by keeping the function of the six valve control switches, putting the moisture separator drain tank level control system into service, the same. There is also a new switch, similar in design to the isolation valve switches, for the backfill valve. The new controls operate similar to other controls on the same panel with a spring return to mid-position switch. Rotation to the left closes the isolation valve and rotation to the right opens the isolation valve. The mid-position, Auto, allows automatic isolation of the valve when plant conditions warrant. These switches are only allowed to be manipulated by following approved, station procedures. This requirement, coupled with approved labeling and an expectation for operators to use self-checking techniques when manipulating controls, will help prevent errors and accidental operation.

a.(4) (Additional item from Section 2.11.1.3 of EPU LAR Attachment 6) The reactor feedwater control system software was updated to initiate a 75% recirculation system runback on a reactor (full) scram to prevent water level from reaching the Level 2 setpoint. This runback is implemented automatically on a reactor scram signal and will be transparent to the operators. This DCN has been installed on all three units since 2008. Procedural guidance is provided and the operators were trained on this change prior to implementation.

a.(5) (Additional item from Section 2.11.1.3 of EPU LAR Attachment 6) Controls for an additional Bus Duct Cooler Fan have been installed since 2008. The control switch for the new cooler fan is identical to the existing fan control switch. The new switch is spaced and labeled appropriately and presents no new human factors concern. The operators were trained on these changes prior to implementation. These switches are only allowed to be manipulated by following approved station procedures. This requirement, coupled with approved labeling and an expectation for operators to use self-checking techniques when manipulating controls, will help prevent errors and accidental operation.

A list of instruments receiving setpoint and/or scaling changes is summarized in the EPU LAR Attachment 6, Table 2.4-2, Changes to Instrumentation and Controls, and Section 2.4.1.3, Technical Specification Instrument Setpoints. Instrumentation and Controls changes are reflected in the operator's procedures and the operators are trained on these changes prior to implementation. The training process determines the proper method for training and any testing required. No controls, displays, or alarms were upgraded from analog to digital instruments as a result of EPU.

b.(1)-1 With respect to clarifying "how the updated values in the TSs translate into corresponding updated values in operating procedures…," the TS mark-ups from EPU LAR Attachment 2, fall into one of the following categories.

a. Rated Thermal Power (RTP) or percent (%) of RTP values are translated directly into the operator's procedures.

b. Average Power Range Monitor (APRM) Neutron Flux-High, Setdown will change from ≤15% to ≤13% of RTP. These values are translated into the operator's procedures reduced by 1%.

c. APRM Flow Biased Simulated Thermal Power-High. This is a change to a formula which the APRMs use to calculate the High trip setpoint. The Current Licensed Thermal Power (CLTP) formula is ≤ 0.66W + 66% RTP, which will change to ≤0.55 W + 65.5% RTP at EPU. These values are translated into the operator's procedures reduced by 1%.

d. Oscillation Power Range Monitor (OPRM) is not bypassed when APRM Simulated Thermal Power is ≥25% and recirculation drive flow is <60% of rated recirculation drive flow. This will change to the OPRM is not bypassed when APRM Simulated Thermal Power is ≥23% and recirculation drive flow is <60% of rated recirculation drive flow. These values are translated directly into the operator's procedures.

e. The bypass setpoint for the Turbine Stop Valve-Closure trip function and the Turbine Control Valve Fast Closure, Trip Oil Pressure-Low trip function will change from ≤30% RTP to ≤26% RTP. This value is converted to the corresponding turbine first stage pressure, reduced to the nearest whole number, and translated into the operator's procedures.

f. Standby Liquid Control (SLC) Weight and Concentration. Every 31 days, the following must be verified:
   1) The minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥203 lbs.
   2) The SLC conditions satisfy the following equation:

   $$\frac{(C)(Q)(E)}{(8.7\text{ wt.\%})(50\text{ gpm})(94\text{ atom\%})} \geq 1$$

   This calculation is directly translated into the chemist's procedures.

g. P_a, the peak calculated containment internal pressure for the design basis loss of coolant accident, at CLTP conditions is 48.5 psig for Unit 1 and 50.6 psig for Units 2 and 3. P_a is changing to 49.1 psig for all three units at EPU conditions. P_a is directly translated into the integrated leakrate test procedure.

h. Gallons of Liquid Nitrogen contained in each Containment Atmospheric Dilution (CAD) nitrogen storage tank. The TS value increased to 2615 gals with EPU. This is an analytical limit. A value for instrument inaccuracy and an additional value for boil-off in a 7-day period will be added to this analytical limit and the resultant value, expressed as a percentage of a full tank (3400 gals), will be translated into the operator's procedures as the new requirement for the minimum amount of liquid nitrogen required to be contained in each of the CAD nitrogen storage tanks.

b.(1)-2 With respect to "whether such updates may present potential challenges for operators," the response, for each of the categories of TS mark-ups from EPU LAR Attachment 2, is as follows.

a. RTP or % of RTP are values that are calculated by the plant process computer and displayed on the reactor operator's computer screen whenever the core thermal power calculation is demanded. The significant digits of the new EPU RTP, or % of RTP, values remain the same as at CLTP conditions for these two parameters. The significant digits of the plant process computer calculation output are sufficient to allow the operator to readily compare this output to the TS values stated in procedures to determine if TS compliance is maintained or if required actions need to be taken. No potential challenges to the operators are created by the new RTP or % of RTP values.

b. The setpoint for the APRM Neutron Flux-High, Setdown will change from ≤15% to ≤13% of RTP. This change is transparent to the operator as the calculation is performed by the APRMs and automatically applied. Procedural guidance will be provided and the operators will be trained on this change prior to implementation.

c. APRM Flow Biased Simulated Thermal Power-High. This is a change to a formula which the APRMs use to calculate the High trip setpoint. The CLTP formula is ≤ 0.66W + 56% RTP, which will change to ≤0.55 W + 65.5% RTP at EPU. This change is transparent to the operator as the calculation is performed by the APRMs and automatically applied. Procedural guidance will be provided and the operators will be trained on this change prior to implementation.

d. At CLTP conditions, the OPRM is not bypassed when APRM Simulated Thermal Power is ≥25% and recirculation drive flow is <60% of rated recirculation drive flow. This will change to the OPRM is not bypassed when APRM Simulated Thermal Power is ≥23% and recirculation drive flow is <60% of rated recirculation drive flow. This change is transparent to the operator as the calculation is performed by the APRMs and automatically applied. Procedural guidance will be provided and the operators will be trained on this change prior to implementation.

e. The bypass setpoint for the Turbine Stop Valve-Closure trip function and the Turbine Control Valve Fast Closure, Trip Oil Pressure-Low trip function will change from ≤30% RTP to ≤26% RTP. This bypass signal is originated from turbine first stage pressure instrument loops and automatically applied. Procedural guidance will be provided and the operators will be trained on this change prior to implementation.

f. SLC Weight and Concentration. Every 31 days, the following must be verified:
   1) The minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥203 lbs.
   2) The SLC conditions satisfy the following equation:

$$\frac{(C)(Q)(E)}{(8.7\ \text{wt.\%})(50\ \text{gpm})(94\ \text{atom\%})} \geq 1$$

These are calculations that are verified monthly by sample and analysis. No comparison to instrumentation is involved and therefore no potential challenges to the operators are created by the new SLC Weight and Concentration values.

g. P_a, the peak calculated containment internal pressure for the design basis loss of coolant accident, at CLTP conditions is 48.5 psig for Unit 1 and 50.6 psig for Units 2 and 3. P_a is changing to 49.1 psig for all three units at EPU conditions. The magnitude of the change is small and the number of significant digits does not change. This value is used in the 10 CFR 50 Appendix J Containment Leakage Rate Test program. During the primary containment integrated leak rate test, the containment is initially pressurized to slightly above the value for P_a (presently for Units 2 and 3, that range is 51.4 to 51.8 psig). This allows the containment to stabilize before starting the official test at a pressure of P_a.

During this test, temporarily installed pressure sensors of very high accuracy are used so comparison to the new P_a value is readily accomplished and therefore no potential challenges to the operators are created by the new P_a value.

h. Gallons of Liquid Nitrogen contained in each CAD nitrogen storage tank. The TS value increased to 2615 gals with EPU. This is an analytical limit. A value for instrument inaccuracy and an additional value for boil-off in a 7-day period will be added to this analytical limit and the resultant value, expressed as a percentage of a full tank (3400 gals), will be translated into the operator's procedures as the new requirement for the minimum amount of liquid nitrogen required to be contained in each of the CAD nitrogen storage tanks. The indication for this parameter is an analog gauge which reads out from 0% to 100% in 2% increments. The zone markings on the gauge are placed at the procedural acceptance value. The reading for % of nitrogen in the tank can be readily compared to the zone markings on the gauge therefore no potential challenges to the operators are created by the new value of gallons required to be contained in each nitrogen storage tank.

b.(2) With respect to describing "any changes to the HSI [Human System Interface] that may need to be made, in connection with the TS changes…," the response, for each of the categories of TS mark-ups from EPU LAR Attachment 2, is as follows.

a. The RTP, or % of RTP, are values calculated by the plant process computer and are then compared by the operator to the TS values contained in the procedures. This comparison process has not changed from CLTP to EPU conditions and no HSI changes are necessary.

b. The new setpoint for the APRM Neutron Flux-High, Setdown will be entered into the APRMs.

c. The new formula for the APRM Flow Biased Simulated Thermal Power-High Trip setpoint will be entered into the APRMs.

d. The new lower limit for APRM Simulated Thermal Power, when the OPRM is not bypassed, will be entered into the APRMs.

e. The new lower bypass setpoint for the Turbine Stop Valve-Closure trip function and the Turbine Control Valve Fast Closure, Trip Oil Pressure-Low trip function will be adjusted at the turbine first stage pressure instrumentation loops.

f. SLC Weight and Concentration. Every 31 days, the following must be verified:
   1) The minimum quantity of Boron-10 in the SLC solution tank and available for injection is $\geq$203 lbs.
   2) The SLC conditions satisfy the following equation:

$$\frac{(C)(Q)(E)}{(8.7\text{ wt.\%})(50\text{ gpm})(94\text{ atom\%})} \geq 1$$

These are calculations that are verified monthly by sample and analysis and no changes to HSI are required.

g. P_a, the peak calculated containment internal pressure for the design basis loss of coolant accident, is compared to temporarily installed pressure sensors of very high accuracy during the primary containment leak rate test. Comparison of these high accuracy pressure instruments to the new P_a value is readily accomplished and therefore no changes to HSI are required.

h. The zone markings on the A and B analog loop gauges for the amount of liquid nitrogen in each CAD system nitrogen storage tank will be extended to reflect the increase in nitrogen required. The zone markings will be extended to the TS analytical limit plus a value for instrument inaccuracy plus a value for boil-off in a 7-day period divided by 3400 gals (number of gallons at 100%) expressed in %.

No re-scaling of existing meters and gauges and no upgrades from analog to digital instruments were required in connection with the TS changes.

ENCLOSURE

APHB-RAI 4

Were any human factors lessons learned from other plant EPU experiences? If yes, describe how significant issues from other plants will be addressed here to prevent recurrence.

TVA Response:

The following activities were performed to identify human factors lessons learned:

1. Reviewed industry lessons learned contained in the following.
   - Institute of Nuclear Power Operations (INPO) 09-005, Power Uprate Implementation Strategies - A Leadership Perspective
   - INPO Significant Event Report (SER) 05-2, Lessons Learned from Power Uprates
   - World Association of Nuclear Operators (WANO) SER 2003-1, Lessons Learned from Power Up-Rates
   - Boiling Water Reactor Owners Group (BWROG)-TP-08-042/NEDO-33159 Revision 2, BWR Owners' Group EPU Committee, Extended Power Uprate (EPU) Lessons Learned and Recommendations
   - Recent Operating Experience related to EPU available through INPO

2. Reviewed power ascension plans from Peach Bottom Atomic Power Station (PBAPS), Grand Gulf Nuclear Station (GGNS), and Hope Creek Nuclear Generating Station.

3. Participated in industry Licensing Manager's Peer Group for Power Uprates.

4. Performed benchmarking on recent EPU plants: PBAPS, Monticello Nuclear Generating Plant, GGNS, Nine Mile Point Nuclear Station.

The following initiatives were applied from the lessons learned.

1. (Generic Lessons Learned) A formerly licensed Browns Ferry Nuclear Plant (BFN) senior reactor operator was assigned full-time to the EPU project.

2. (Generic Lessons Learned) The station organizations have been involved in the development and review of changes related to the EPU project.

3. (Generic Lessons Learned) An assessment of changes to operating margins of equipment and systems to identify, evaluate and address potential operator challenges was initiated.

4. EPU projects at other plants have found problems with their steam dryer design. As a result, third party reviews on the design and analysis of the BFN replacement steam dryers (RSD) were performed.

5. An EPU project at another plant experienced the introduction of foreign material in the reactor vessel when the instrumentation and cabling for the vibration monitoring equipment, installed on the RSDs, failed. As a result, at BFN, the attachment method for the RSD vibration instrumentation cabling has been improved.

6. BFN and one other plant that submitted EPU license amendment requests, which relied on Containment Accident Pressure (CAP) credit in demonstrating adequate Net Positive Suction Head (NPSH) for the Emergency Core Cooling System (ECCS) pumps, experienced long review periods by the NRC placing their EPU project schedules at risk. As a result, BFN is performing the analyses necessary to support elimination of the reliance on CAP credit in demonstrating adequate NPSH for the ECCS pumps.

7. An EPU project at another plant increased the Standby Liquid Control (SLC) Boron-10 enrichment to limit peak suppression pool temperature during an Anticipated Transient Without Scram (ATWS) and thus prevented having to depressurize the reactor due to Heat Capacity Temperature Limit conditions. BFN will increase the Boron-10 enrichment for the same reason.

8. An EPU project at another plant had a long history of safety-relief valve maintenance issues due to vibration. As a result, the valves were instrumented with accelerometers for monitoring post-EPU implementation. Although BFN does not have a history of safety-relief valve maintenance issues due to vibration, selected safety-relief valves, as well as four other power-operated valves, will be instrumented with accelerometers based on this industry operating experience.

9. Another plant found during power ascension, after implementing EPU, that the reactor was below the required reactor pressure range (950 to 1040 psig) required by Technical Specifications (TSs) for running the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) surveillances. As a result, BFN has added steps to the startup test instruction to document and resolve this issue should the electrohydraulic control (EHC) setpoint need to be adjusted to allow performance of HPCI/RCIC high pressure surveillances.

10. At another Boiling Water Reactor (BWR), it was discovered that the plant was setting the bypass for the Turbine Control Valve Fast Closure and Turbine Stop Valve Closure trip functions incorrectly. The setting was intended to be based on a percentage of reactor thermal power and instead, the plant had wrongly based the setting on rated turbine power. BFN will ensure this setting is correct by implementing the recommendations contained in General Electric (GE) Service Information Letter (SIL) 423, Erroneous SCRAM Bypass Setpoint.

11. At another BWR, several errors were discovered while calibrating the feedwater flow element transmitters. The combined effect of these errors resulted in an indicated feedwater flow 1.1% lower than actual flow. As a result, the plant operated above the rated licensed thermal power. BFN will ensure the accuracy of feedwater flow by implementing the recommendations contained in GE SIL 452, Supplement 1, Revision 1, Feedwater Flow Element Inspection and Accuracy.