January 31, 2005

10 CFR 54

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop: OWFN P1-35
Washington, D.C. 20555-0001

Gentlemen:

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 LICENSE RENEWAL APPLICATION (LRA) – RELATING TO SECTION 3.0 UNIT 1 LAY UP QUESTIONS – RESPONSE TO AGING OF MECHANICAL SYSTEMS DURING THE EXTENDED OUTAGE OF BROWNS FERRY NUCLEAR PLANT UNIT 1 – NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) (TAC NOS. MC1704, MC1705, AND MC1706)

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's license renewal application, the NRC staff, by letter dated December 16, 2004, identified areas where additional information is needed to complete its review.

The specific areas requiring a request for additional information (RAI) are follow up questions relating to the aging of mechanical systems during the extended outage of BFN Unit 1. These follow up questions were a second round of

Unit 1 lay up questions derived from the license renewal application.

The enclosure to this letter contains the specific NRC requests for additional information and the corresponding TVA response.

If you have any questions regarding this information, please contact Ken Brune, Browns Ferry License Renewal Project Manager, at (423) 751-8421.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 31st day of January, 2005.

Sincerely,

Original signed by:

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s://Licensing/Lic/BFN LR Section 3.0, Second Round Unit 1 Lay Up RAIs, TVA Response Letter.doc

ENCLOSURE

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

RESPONSE TO AGING OF MECHANICAL SYSTEMS DURING THE EXTENDED OUTAGE OF BROWNS FERRY NUCLEAR PLANT UNIT 1 - SECOND ROUND NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) FROM SECTION 3.0 of the LRA.

(SEE ATTACHED)

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

RESPONSE TO AGING OF MECHANICAL SYSTEMS DURING THE EXTENDED OUTAGE OF BROWNS FERRY NUCLEAR PLANT UNIT 1 - SECOND ROUND NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) FROM SECTION 3.0 of the LRA.

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The specific areas requiring a request for additional information (RAI) are follow up questions relating to the aging of mechanical systems during the extended outage of BFN Unit 1. These follow up questions were a second round of Unit 1 lay up questions derived from the LRA. A teleconference between TVA and NRC staff was held on January 11, 2005 to clarify some of the questions. The response provided below reflects the result of the teleconference.

The specific NRC requests for additional information and the corresponding TVA responses follow.

NRC Follow-up RAI to RAI-3.0-1 LP(b)

The applicant stated in its response to RAI 3.0-1 LP, that the impurities (i.e.; chlorides and sulfates in the reactor coolant system (RCS) water) are monitored once in two weeks during wet layup. Since the frequency of the verification of the RCS water chemistry is once every two weeks, pitting and crevice corrosion of the reactor pressure vessel (RPV), RPV internals and RCS components, could occur.

(1) Identify the potential sources in the primary systems which can cause impurities to leak into the primary systems.

(2) Provide information regarding its past experience, if any, related to any sudden increase in concentration of chlorides and sulfates in the RCS water during the wet

layup, and the corrective actions taken to prevent impurities migrating into crevices in the RCS.

(3) Identify the crevice locations in the RPV, RPV internals and RCS components, which will not be replaced and where accumulation of aggressive ions such as chlorides and sulfates inside the crevice can enhance the likelihood of crevice and pitting corrosion during the wet layup.

(4) Provide information regarding the type of the intended inspection prior to restart and during the period of extended operation, to be use to identify this aging effect due to pitting and crevice corrosion in the RPV, RPV internals and RCS components which will not be replaced.

TVA Reply to NRC Follow-up RAI to RAI-3.0-1 LP(b)

(1) During wet lay-up, the Unit 1 RCS was operated as a closed loop system (i.e., the Reactor Water Cleanup (RWCU) system in-service, low system volume loss, infrequent make-up and with the RPV head in place). Therefore it was not normally in contact with any environment or conditions that could introduce undetected impurities. The only potential sources of impurities (i.e. chlorides and sulfates) were impurities contained in the make-up water and impurities that may be released from new RWCU demineralizer ion exchange resin. The make-up water for the Unit 1 RWCU was plant condensate water, which is the same source used for makeup for Units 2 and 3. Whenever new ion exchange resins are applied, water chemistry is monitored to ensure that there are no impurities released. If any impurities are detected, a new ion exchange resin precoat would be applied to the RWCU demineralizer. Although lower flow areas within the RCS were expected to exist, over time with flow and diffusion, the chemistry sample results obtained are representative of the water chemistry experienced within the total RCS. At a RWCU flow rate of 100 gpm and assuming a 90,000 gallon RCS volume, the RCS volume would be processed ("turned-over") approximately 1.5 times per day.

Based on the closed loop system, lack of potential unmonitored sources of impurities, the regular "turn-over" of the RCS volume through the RWCU system, and the verification of RCS chemistry every two weeks, there is high confidence that no excessive impurities were introduced into the RCS during wet layup.

(2) A review of the Unit 1 RCS chemistry data from 1999-2002 shows that chloride and sulfate were controlled and maintained at acceptable levels (< 15 ppb). The period 1999-2002 was selected because the data was digitally stored beginning in 1999 and thus quickly retrievable, and taken through 2002, when the RCS was drained for piping replacement. Based on the wet layup configuration described in (1) above, and in the original response to RAI-3.0-1 LP, and the chemistry monitoring program described in the original response to RAI-3.0-1 LP, TVA is assured that this data is representative of the chemistry conditions throughout the RCS wet layup period. There were no occurrences of sudden increases in the concentration of chlorides and sulfates in the RCS.

(3) See the response provided in (4) below.

(4) Based on the chemistry controls in place during Unit 1 wet layup (See the response to (1) and (2) above), there are no areas in the RPV, the RPV internals or RCS components considered susceptible to crevice and pitting corrosion due to an accumulation of aggressive ions that are not already being inspected, refurbished, or replaced. The response to RAI 3.0-9 LP below discusses the piping and component inspections, replacements, and refurbishments being performed as part of Unit 1 restart activities. Therefore, no augmented provisions are required in the associated system aging management programs as a result of BFN Unit 1 wet layup.

NRC RAI 3.0-9 LP

The LRA Appendix F indicates that significant sections of piping and components have been or will be replaced prior to restart. It is not clear if Appendix F includes all piping and components that has been or will be replaced prior to restart. Based on the responses to RAI for Section B.2.1.4 developed during the license renewal audit inspection during the weeks of June 21, 2004 and July 26, 2004, it was stated that repaired or replaced components will receive a preservice examination in accordance with the requirements of ASME Section XI Subsection IWB, IWC, or IWD programs related to the components being repaired or replaced and prior to returning the system to service. In this response, it was stated that a re-baseline inspection will be performed on the remaining Class 1, 2 and 3 components that have not been repaired or replaced.

(1) Please provide information to identify the basis, such as inspections or suspected degradation, to determine which components need to be replaced and those that do not.

(2) Clarify if the LRA Appendix F includes all piping and components that will be replaced prior to startup and identify in a simplified boundary diagram, those specific sections of piping and components that have recently been or will be replaced and those that have not been replaced.

(3) Please refer to RAI 3.0-11 LP; clarify appropriate layup or cleanliness programs and inspections that are in use and planned for these components. Please refer to RAI 3.0-10 LP; provide information for those systems or portions of systems and components that have not been recently replaced and were subject to the extended layup.

TVA Reply to NRC RAI 3.0-9 LP

In a teleconference between TVA and the NRC staff on January 11, 2005, held to clarify the Staff's questions, it was agreed that a detailed description of the process used to establish the material condition of Unit 1 piping systems for restart would be sufficient in response to RAI 3.0-9 LP and RAI 3.0-10 LP. The following discussion describes that process.

As license renewal approval was a key assumption in the economic feasibility of Unit 1 restart, the overall management philosophy for Unit 1 restart was to return the plant to operation in a condition that would support long-term safe and reliable operation of the unit, including the anticipated 20-year period following license renewal. Therefore, for some cases, TVA decided up front to replace entire piping sections and components, rather than expend extensive engineering resources to confirm that the existing piping and equipment was acceptable. TVA also decided up front to refurbish a large population of pumps and valves not already planned for replacement.

With this management philosophy as a basis, TVA applied lessons learned from the Units 2 and 3 restart programs and operating experience from all three units in its decision to replace large portions of key piping systems, perform targeted inspections of suspected problem areas, and perform sample inspections of the remaining portions of the systems. The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components. Rather, TVA either replaced the piping and components or performed appropriate inspections to establish the physical condition of systems and components not being replaced.

To identify the scope of replacements, refurbishments, and inspections required for Unit 1 piping systems, TVA considered the following:

- Previously Identified Design Issues
- Operating Experience
- Systems Maintained in Service During Shutdown
- Inspections

Based on this review, TVA then identified which piping runs and components would be replaced, and those that would be inspected and evaluated further.

Previously Identified Design Issues

Previously identified design issues are those such as IGSSC susceptible piping which had been identified by NRC Generic Letter 88-01. For Unit 1, the decision was made to replace all IGSSC susceptible piping in the drywell with IGSSC resistant piping. This includes Reactor Recirculation and safe ends, Core Spray, Residual Heat Removal, Reactor Water Cleanup, and jet pump instrumentation nozzle safe ends. The welds for this piping, including the safe end to vessel nozzle welds being replaced inside the drywell, will be stress relieved using the mechanical stress improvement process (MSIP) in which the weld root is placed in compression through the application of an external compressive load to the pipe.

Unit 1 piping and components are being installed in accordance with the USAS B31.1 code 1967 edition with post modification inspections conducted in accordance with the ASME Section XI 1995 edition/1996 addendum. The radiography is conducted at the time of installation while the Section XI examinations will be conducted after the application of the MSIP process.

Additionally, the Reactor Water Cleanup piping outside the drywell is being replaced to reconfigure the system to improve reliability of the pumps. Another example of previously identified design issues was retubing the main condenser to remove copper from the condensate system and improve reactor water chemistry.

Operating Experience

Several significant pipe replacements are being done based on operating experience. For example, Units 2 and 3 have recently replaced extraction steam piping inside the condensers due to flow accelerated corrosion (FAC). For Unit 1, all extraction steam piping was replaced with a FAC resistant piping. Another example is the Unit 1 Loop I of the residual heat removal service water (RHRSW) system where experience from Unit 3 restart activities indicated that this piping would need to be replaced. This system communicates to underground piping that is filled with water. Water vapor from the underground piping migrated into the piping that was inside the reactor building in a warm environment. This caused corrosion that required total pipe replacement. Other RHRSW non-buried piping in the service water tunnels did not exhibit this corrosion due to the cooler environmental temperatures. The Unit 1 Loop II of RHRSW was in service for Unit 2 operation and was full of treated raw water. Ultrasonic inspections confirmed that this piping did not exhibit the corrosion identified on Loop I.

Systems Maintained in Service During Shutdown

Several Unit 1 systems continued to operate during the extended outage to maintain Unit 1 in a defueled condition or to provide necessary support of the operation of Units 2 and 3. Examples of these piping systems are:

- Fuel Pool Cooling System
- Portions of the Control Rod Drive (CRD) System
- Portions of the Raw Cooling Water (RCW) System
- Portions of the Reactor Building Closed Cooling Water (RBCCW) System
- Portions of the Residual Heat Removal (RHR) System
- Portions of the Residual Heat Removal Service Water (RHRSW) System
- Portions of the Emergency Equipment Cooling Water (EECW) System
- Portions of the Control Air System

These systems were not in layup and therefore maintained in a physical condition similar to that found in Units 2 and 3. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as that found in the operating units. Additionally, since the Unit 1, 2 and 3 reactor buildings are one continuous structure, the external operating environments are the same. Even though Unit 1 was in an extended outage, the overall environmental condition of the plant was maintained consistent with Units 2 and 3. Unit 1 had the normal ventilation systems in service, equipment was maintained to prevent system leakage, etc., so that the equipment was not subjected to aggressive external conditions. For those portions of systems not in service, inspections were performed as described below.

Tables 1 and 2 below summarize the piping replacements and inspections performed.

Inspections

For those portions of piping systems not initially identified for replacement, Engineering determined the physical condition of the existing Unit 1 piping systems through a combination of visual and ultra-sonic inspections, coupled with a re-baselining of the ASME XI welds. In no case did the Unit 1 restart project take credit for the layup program as the sole means of establishing the acceptability of the piping condition. Regardless of the layup status of the system, inspections were conducted as described below. The systems were inspected and their physical condition verified as part of the restart effort.

Reactor Vessel

The reactor vessel was partially visually inspected in 2001 and found to not exhibit adverse effects from the layup period. See Table 2 for information on the inspections to be performed.

Pipe and Fittings

The piping was evaluated based on lessons learned from Unit 2/3 restart efforts and subsequent operation, Unit 1 Operating experience and the piping status during the extended outage to identify piping systems that should be inspected.

Specific piping systems had wall thickness measurements taken on a sample basis. Rather than performing random inspections, targeted sampling was used to identify the locations most susceptible to degradation. The locations for the wall thickness measurements were based on:

- Potential areas of water accumulation within the piping system
- Water filled dead legs on systems which had been in service

- Locations where accelerated wear would be expected to occur (e.g., the heel of elbows or the backside of tees where impingement could occur during operation)
- Areas of piping systems found to be suspect during Units 2/3 restart and operation

The recorded wall thickness measurements were reviewed and evaluated with respect to the calculated USAS B31.1 Code 1967 Edition required minimum wall thickness based on the piping system stress analysis and including a 40-year corrosion allowance. Even though the remaining plant life following license renewal will only be approximately 27 years, a 40-year corrosion allowance was used to ensure reliable operation during the period of license renewal. If the piping wall thickness measurements were below the required minimum design wall thickness plus corrosion allowance, the piping was either replaced or repaired depending on the extent of the condition.

Two examples of inspections are the Main Steam and Feedwater piping. While this piping was not considered susceptible to degradation, UT examinations were done to measure wall thickness at the most vulnerable locations. The results showed that the piping met all design requirements and does not require replacement.

Another example is Raw Cooling Water piping with dead legs filled with raw water. Inspections were performed and degradation was identified in numerous locations. All of the identified unacceptable piping is being replaced.

Other opportunities for inspection also occur during Unit 1 restart activities. As part of work to replace existing piping, valves, and inline components, it is a standard work practice that when a piping system is breached, the adjacent piping and/or components are inspected for any observable degraded condition (e.g., erosion, corrosion, wall-thinning, etc.). If a questionable condition is observed, it is documented in TVA's corrective action program. When these conditions involve a questionable wall thickness, wall thickness measurements are taken and the condition evaluated based on the acceptance criteria above.

An example of this was the cross-under piping from the high pressure turbine to the moisture separators. A manway on this piping was opened and the piping was visually inspected. The inspection identified evidence of significant steam erosion in the piping. This was found to be the result of installing the incorrect grade of piping material during original construction of Unit 1. All of this piping has been replaced on Unit 1 and both Unit 2 and Unit 3 were verified to have the correct piping installed.

Valves

Valves within the piping systems were reviewed to determine if the valves needed to be replaced or refurbished. During the Unit 1 restart effort, approximately 3000 valves will be replaced. Also, it is estimated approximately 1000 valves will be tested and refurbished. When valves are refurbished, the valve components are visually inspected (ultrasonic inspections if necessary) to determine if degradation has occurred that would affect operation of the valve. These inspections include:

- Inspection of the pressure retaining components (valve body, bonnet, etc.) for pitting or erosion and the valve body or bonnet wall thickness

- Inspection of the non-pressure retaining components to ensure their condition will support proper operation of the valve

Examples of major valves that have been refurbished:

- Reactor water recirculation system pump suction and discharge valves
- Residual heat removal system injection check valves

Examples of major valves that have been replaced:

- High pressure coolant injection steam line primary containment isolation valves
- Reactor water cleanup system primary containment isolation valves

Pumps

Significant effort is also being expended to ensure that Unit 1 pumps are in top condition to support long term safe and reliable operation. Pump pressure retaining components (pump casing, etc.) are inspected (visual and/or ultrasonic) to determine if the pump needs to be replaced or refurbished. Inspection of the non-pressure retaining components is also conducted to ensure their condition will support proper operation of the pump. Additionally, several pumps were replaced to increase flow capacity to operate at extended power uprate (EPU) conditions.

Examples of pumps that have been replaced:

- Reactor Water Cleanup pumps (2 each) – IGSCC related
- Condensate Booster pumps (3 each) – EPU related
- Reactor Feedwater pumps (3 each) – EPU related

Examples of pumps that have been refurbished:

- Reactor Recirculation pumps (2 each)
- Residual Heat Removal pumps (2 each)
- Core Spray pumps (4 each)

<u>Heat Exchangers</u>

Heat exchangers associated with the piping systems were inspected (visual, ultrasonic and eddy current) to determine if the heat exchanger shell and/or tube bundle needed to be replaced or refurbished. There are approximately 50 heat exchangers in Unit 1. All heat exchangers that were not being replaced due to design changes are being inspected.

- Heat exchangers will have 100 percent of their tubes eddy current tested to ensure the integrity of the tube bundles
- The safety-related heat exchangers will have their shell casing wall thicknesses checked utilizing ultrasonic testing to ensure the wall thicknesses are in accordance with the design wall thickness requirements
- Visual inspections of the heat exchangers for pitting or erosion are performed when manway covers are removed or the connecting piping is replaced or breached

Examples of heat exchangers that have been replaced:

- Reactor Water Cleanup Regenerative (3 each)
- Main Turbine Lube Oil (2 each)
- Reactor Feedwater Pump Lube Oil (1 each)
- Reactor Building Closed Cooling Water (2 each)

Examples of heat exchangers that have been refurbished:

- Main Condenser (complete tube replacement)
- Off Gas Condenser (new tube bundles)
- Off Gas Pre-heater (new tubes)
- Alternator Exciter Coolers (new tube bundles)

The extensive inspections of heat exchangers gives high level of confidence that the heat exchangers will support safe and reliable operation of Unit 1 after restart.

Appendix F of the license renewal application did not include all piping and components that will be replaced prior to startup. The purpose of Appendix F is to show those Unit 1 restart activities affecting the license renewal application, and explain how completion of each of them will affect the application. This is fully explained in Appendix F, pages F-2 through F-3.

Summary

The application of the targeted sampling inspections and the number of inspections performed has established a high level of confidence that those systems of any questionable integrity have been identified, inspected and properly addressed relative to the replacement or non-replacement of the piping system and/or its components.

The combination of piping replacements identified through previously identified design issues, operating experience, and other inspections has identified approximately 16,000 feet of large bore piping and 26,000 feet of small bore piping to be replaced.

The results of the reviews of operating experience, design issues, and inspections is provided in Table 1. The systems listed are those in which significant piping or components were identified for replacement or refurbishment.

Table 2 below provides the details and extent of the ASME Section XI Re-Baseline inspections that will be conducted on Unit 1 piping systems prior to operation. The re-baseline effort is equivalent to performing a complete 10-year interval's quantity of examinations during the Unit 1 restart effort.

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements

System Name	Location	Inspection Work Method	Method Used to Determine System Integrity	Description of the Piping System Refurbishment/Replacement
Main Steam 001	Drywell	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Refurbishment of Containment Isolation valves • Replace drain line isolation valve
Main Steam 001	Reactor Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Refurbishment of Containment Isolation valves • Replace drain line isolation valve
Main Steam 001	Turbine Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged except for the cross-under/cross-over piping described below • Refurbishment of turbine control and stop valves
Main Steam Cross-Under / Cross-Over 001	Turbine Building	Maintenance Work Order	• Unit 1 operational history • Cleanliness Verification	• All of the Cross-Under piping (HP Turbine to Moisture Separators) replaced due to improper material in initial piping • Selected portions of the Cross-Over Piping (Moisture Separators to Combined Intermediate Valve) replaced • Replacement piping was 2-1/4% Cr. material
Condensate 002	Turbine Building	DCN 51401 & DCN 51402	• System component integrity wall thickness measurements • EPU impact on equipment requirements	• Piping system remains unchanged • Condensate pump impellers and motors replaced for extended power uprate operation • Condensate Booster pumps replaced for extended power uprate operation
Reactor Feedwater 003	Drywell	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Feedwater check valves replaced for Stellite reduction
Reactor Feedwater 003	Reactor Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Satisfactory inspection. Piping system remains unchanged • Feedwater check valves replaced for Stellite reduction

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements				
System Name	**Location**	**Inspection Work Method**	**Method Used to Determine System Integrity**	**Description of the Piping System Refurbishment/Replacement**
Reactor Feedwater 003	Turbine Building	Maintenance Work Order	• System component integrity wall thickness measurements • Cleanliness Verification	• Minimum flow valves replaced due to wear experience on Units 2 and 3 • Minimum flow piping to condenser replaced with stainless steel to prevent FAC • Remaining piping inspected satisfactorily and remains unchanged
Extraction Steam 005	Turbine Building	DCN 51116 & Maintenance Work Order	• Units 2&3 Restart Lessons Learned • Units 2&3 FAC program results • System component integrity wall thickness measurements • Cleanliness Verification	• Heater's 2, 3, 4 & 5 piping inside and outside of the condenser replaced with 2-1/4% Cr. material to prevent FAC • Heater 1 piping remains unchanged
Heaters Drains & Vents 006	Turbine Building	DCN 51116 & Maintenance Work Order	• Units 2&3 Restart Lessons Learned • Units 2&3 FAC program results • System component integrity wall thickness measurements • Cleanliness Verification	• Pipe sizes typically 2" and smaller replaced with 2-1/4% Cr. material to prevent FAC • Selected sections for inspections/replacements based on FAC experience from Units 2 and 3 • • Replaced Heater Drain and Moisture Separator Level Control valves for improved flow control and reliability
Residual Heat Removal Service Water 023	Reactor Building	DCN 51177	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements on Loops "A" & "C" • Loop "B" & "D" in operation supporting Units 2 & 3	• Complete like-for-like replacement of Loop I carbon steel piping • LoopII inspected with no replacement required (continuously operated in support of Unit 2/3 operation • Replacement of all four discharge flow control valves for improved flow control

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements

System Name	Location	Inspection Work Method	Method Used to Determine System Integrity	Description of the Piping System Refurbishment/Replacement
Raw Cooling Water 024	All Buildings	Maintenance Work Order	• Portions of system remained in operation to support operation of Units 2 and 3	• Satisfactory inspection of large bore piping. Large bore piping remains unchanged. • Approximately 3000 feet of small bore piping replaced like-for-like due to corrosion caused by improper layup • Selected dead legs removed from the plant due to piping no longer required due to equipment changes. • Other dead legs remain in place to support intermittent operations.
Fire Protection 026	Reactor Building	DCN 51180 & Maintenance Work Order	• System component integrity wall thickness measurements at selected locations of vertical main risers which were not replaced	• Replacement of the header and branch piping in reactor building with galvanized carbon steel to bring system into conformance with NFPA code
Condenser 027	Turbine Building	DCN 51113	• Replacement of tubes containing Copper • Cleanliness Verification	• Satisfactory inspection. Piping system and condenser structure remain unchanged • Replaced and upgraded condenser tube material to Sea Cure stainless steel to remove copper from the system.
Emergency Equipment Cooling Water 067	Reactor Building	DCN 51192	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Replacement of 4" & smaller piping with material changed from carbon steel to stainless steel (316/316L)
Reactor Water Recirculation 068	Drywell	DCN 51045	• IGSCC Issues	• Complete large bore replacement with IGSCC resistant 316NG materials • 2" and smaller piping replaced with stainless steel (316/316L) • Pumps and large bore valves refurbished

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements

System Name	Location	Inspection Work Method	Method Used to Determine System Integrity	Description of the Piping System Refurbishment/Replacement
Reactor Water Cleanup 069	Drywell	DCN 51046	• IGSCC Issues	• Complete replacement of piping with IGSCC resistant 316NG materials • Complete replacement of valves with 316L material
Reactor Water Cleanup 069	Reactor Building	DCN 51194	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Complete replacement of hot piping (316NG) and regenerative heat exchangers (316L) (3 heat exchangers) • Piping rerouted to cool water before water enters pumps to increase pump seal life • Complete replacement of valves with 316L material in hot segments of piping
Reactor Building Closed Cooling Water 070	Drywell	DCN 51148	• Units 2&3 Restart/Operational Lessons Learned • System component integrity wall thickness measurements	• Complete replacement with material changed from carbon steel to stainless steel (316/316L) to eliminate corrosion materials in the system and drywell. • All new valves installed
Reactor Building Closed Cooling Water 070	Reactor Building	DCN 51195	• Units 2&3 Restart/Operational Lessons Learned • System component integrity wall thickness measurements	• Replaced "A" & "B" Heat Exchangers with upgraded heat exchanger tube material. Entire heat exchanger replaced in lieu of retubing existing heat exchanger due to cost considerations.
Reactor Core Isolation Cooling 071	Reactor Building	DCN 51196	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Steam trap drain line replacement with 2-1/4% Cr. materials to prevent FAC • In lieu of refurbishment, replaced several large bore valves
High Pressure Coolant Injection 073	Reactor Building	DCN 51198	• Units 2&3 Restart Lessons Learned • System component integrity wall thickness measurements	• Steam trap drain line replacement with 2-1/4% Cr. materials to prevent FAC • In lieu of refurbishment, replaced several large bore valves

Table 1 - Browns Ferry Unit 1 Restart Project - Piping System Replacements

System Name	Location	Inspection Work Method	Method Used to Determine System Integrity	Description of the Piping System Refurbishment/Replacement
Residual Heat Removal 074	Drywell	DCN 51151	• IGSCC Issues	• Complete replacement with IGSCC resistant 316NG materials • Large bore valves refurbished
Core Spray 075	Drywell	DCN 51152	• IGSCC Issues • System component integrity wall thickness measurements	• Complete replacement with IGSCC resistant materials • Stainless steel material (304) was replaced with a high toughness carbon steel material A333, Gr. 6 • Large bore valve materials are stainless steel
Core Spray 075	Reactor Building	DCN 51200	• IGSCC Issues • System component integrity wall thickness measurements	• Very short section of stainless steel material (304) was replaced with a high toughness carbon steel material A333, Gr. 6 to eliminate a weld overlay

Table 2 – Browns Ferry Unit 1 Restart Project - Piping System Inspections

Program	Inspection Classification	Inspection Scope
Reactor Pressure Vessel (IVVI)	• Component Integrity Inspections will be performed • Partial IVVI examinations were conducted in 2001to determine any major conditions. • The visual examinations will be completed after vessel flood up and water clarity has been re-established.	• BWRVIP-18 - Core Spray • BWRVIP-25 - Core Plate • BWRVIP-26 - Top Guide • BWRVIP-27-A - Standby Liquid Control • BWRVIP-38 -Shroud Support • BWRVIP-41 - Jet Pump • BWRVIP -47 - Lower Plenum (CRD, Incore) • BWRVIP-48 Vessel Attachment Welds • BWRVIP-49-A Instrument Penetrations • BWR-74-A - Reactor Pressure Vessel (license renewal only) • BWRVIP-76 - Core Shroud
Section XI Re-Baseline Inspections	• IWB Class 1	• 25% of piping welds accessible without removal of supports or permanent features for those systems not being replaced. Selection basis: system distribution, welds that had not been examined in the 1st Interval • 100% of component supports • RPV vessel head and longitudinal shell welds • 100% bolting • 100% accessible RPV interior and interior attachments (VIP)
	• IWC - Class 2	• 7.5% sample of welds on each system • 100% component supports
	• IWD- Class 3	• 100% component supports including attachments

NRC RAI 3.0-10 LP

For those systems or portions of systems that have been subject to an extended layup, one-time inspections prior to start-up may not be appropriate as a verification program for extended layup or chemistry control for certain materials where degradation is expected and additional inspections may be required. Industry documents, such as EPRI NP-5106 "Sourcebook for Plant Layup and Equipment Preservation," and EPRI CS-5115 "Guidelines: Long-Term Layup of Fossil Plants," recommend periodic inspections during layup to determine the effectiveness of the layup program. EPRI NP-5106 specifically recommends that a surveillance and assessment program is needed to monitor the effects of outage or storage conditions on nuclear power plant components, otherwise, evidence of bad layup often will not even manifest itself until after a plant has returned to power. This document also states that, in order to monitor the effectiveness of the layup practice and to differentiate between the effects of power operation and layup, it would be necessary to inspect components immediately after plant shutdown and again just prior to start-up. EPRI CS-5115 recommends that a routine monitoring program must be established to check the effectiveness of the layup program, specifically states that a routine annual inspection of all equipment plus general condition of the plant should be conducted. Aging management program (AMP) XI.M32 describes the one-time inspection as a program to verify the effectiveness of an aging management program and confirm the absence of an aging effect. This AMP also describes the use of the one-time inspection program to be acceptable where either an aging effect is not expected to occur but there is insufficient data to completely rule it out or an aging effect is expected to progress very slowly.

EPRI NP-5106 and EPRI NP-5580, "Sourcebook for Microbiologically Influenced Corrosion in Nuclear Power Plants," identify that aging effects that are expected for nearly all materials during the extended layup and plant operation, unless effective layup, chemistry programs and inspections have been implemented to confirm the absence of aging. Although consistency with the BWRVIP-79 is credited, no inspection data has been referenced in the LRA, to confirm that the aging effects are not occurring or are expected to occur at a very slow rate. Responses to RAIs 3.3-1 LP and 3.3-2 LP, just included a discussion that one-time inspection will be performed prior to Unit 1 restart to verify the material condition, but did not included any information in regard to the rate of degradation or a justification that using one-time inspection is sufficient to identify material degradation. The response to RAI 3.01 LP (b)2 indicated that one-time inspection does not differentiate between the rates of aging in different environments. The response to RAI 3.0-5 LP also stated that it was not the intent of this AMR to determine the rate of loss of material. In addition, there is no information in the LRA or in the responses to these RAIs to justify that the rate of degradation during the extended outage was bounded by the degradation rate during plant operation. Therefore, please address the following staff concerns:

Application of one-time inspection versus periodic inspections

One-time inspections may not be appropriate where degradation is expected to occur or not occur very slowly. For systems not associated with the BWR VIP program, please justify why a one-time inspection is appropriate for aging management in lieu of periodic inspections. Please clarify if previous inspections performed during the extended outage are being credited, and clarify the extent and results of those inspections. If the one-time inspection is intended to represent a baseline and additional inspections will be applied to evaluate future degradation, please clarify and explain how follow-up inspections will be performed, including information to support the effectiveness of the corrective action process to resolve aging degradation.

Review of one-time inspections

NUREG-1801 XI.M32 indicates that one-time inspections or any other action or program is to be reviewed on a plant specific basis. If one-time inspection program is credited as being consistent with NUREG-1801, the information provided in the LRA is not sufficient to determine that the program can be used on a plant specific basis. Please provide additional information on each element of the one-time inspection program to support a plant specific review. Alternatively, please provide a plan to implement the program with sufficient time to validate its effectiveness. Since this program is to be implemented prior to start-up, it should be readily available now or in the near future. The following specific information should be included:

(1) Scope of the program
Identify specific components and locations subject to one-time inspection or clarify the basis for selecting a particular sample size. This concern is addressed in greater detail below.

3) Parameters Monitored/Inspected
Identify specific parameters monitored/inspected such as wall thinning, evidence of general corrosion, cracking, pitting, erosion, MIC and fouling.

(4) Detection of Aging Effects
Identify NDE techniques applied to detect degradation and clarify which components will be inspected internally. Identify qualifications of inspection personnel and any specific training to improve techniques where results are subjective or qualitative.

(5) Monitoring and Trending
Clarify how plant specific and industry wide experience will be applied to the techniques used to perform follow-up inspections.

(6) Acceptance Criteria
Define general acceptance criteria with justification such as no evidence of any degradation or minimum wall thickness plus an allowance for future degradation. Also identify where specific established acceptance criteria is or will be defined.

(7) Operating Experience
Although the program is new and no operating experience with the program exists, there should be operating experience with the effectiveness of various inspections and the corrective action process to detect and correct aging degradation. Clarify if sufficient data is now available or when it will be available. Provide examples of such operating experience and identify the results of any independent assessments to evaluate the effectiveness of plant inspections and the corrective action process to detect and correct aging degradation. Also, as identified above, the one-time inspection program should be implemented early enough to validate its effectiveness.

Sample size for one-time inspections

Section B.2.1.29 of the LRA, indicates that elements of the one-time inspection program will include determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. NUREG 1801, XI.M32, recommends a review of one-time inspections on a plant specific basis including determination of the sample size. Identify when the sample size is to be developed and provide the basis for selecting an adequate sample size including the basis for expanding the sample size and locations.

Rate of degradation

The rate of degradation is important to determine the need and timing for follow-up inspections. The information submitted in the LRA and RAI responses, letter dated October 8, 2004, did not clarify whether the conditions that existed during the extended outage were more severe or less severe than during plant operation. As a result, the rate of degradation cannot be readily determined from a one-time inspection. Clarify how the rate of degradation will be determined from a one-time inspection to facilitate planning follow-up inspections and to predict the remaining service life. Also, clarify how an appropriate schedule of one-time inspection is to be determined, please refer to the following section.

Schedule for one-time inspection

Section B.2.1.29 of the LRA, states that one-time inspection will be completed before the end of the current operating license term, but the inspection will not be scheduled too early in the current operating license term so that there will be no questions raised regarding the continued absence of aging effects prior to and near the extended period of operation. The response to RAI 3.01 LP (b)2 stated that a one-time inspection will be performed prior to restart. Identify with justification, such as using information on the rate of degradation or otherwise, the appropriate timing of the one-time inspection to demonstrate that the inspection is early enough to validate the effectiveness of the program, and yet late enough to account for latent aging effects. Please clarify if periodic inspections rather than one-time inspections are necessary.

Microbiologically Influenced Corrosion (MIC)

Industry documents, such as NP-5580, "Sourcebook for Microbiologically Influenced Corrosion in Nuclear Power Plants," indicate that MIC is potentially a significant corrosion mechanism during an extended outage and during plant operation. Various corrosion mechanisms that would not be active during operation often appear during layup as water chemistry controls may not be as stringent as during high temperature operation when greater attention is focused on impurity control. The response to RAI 3.0-3 LP states that a review of operating experience did not identify MIC as a concern in treated water.

It is not clear if inspections or monitoring for microbes were actually performed in susceptible areas. Clarify why one-time inspections are appropriate for locations with stagnant, low flow or intermittent flow, where MIC is expected on the basis of industry operating experience due to possible ineffective chemistry control in these regions. Identify the results of any inspections performed in low flow or stagnant areas to demonstrate that aging effects are not expected to occur or are expected to occur slowly. Also provide information on any corrosion monitoring programs for MIC, including augmented inservice inspection of susceptible areas and corrosion coupons or spool pieces, unless periodic inspection are taken into consideration to evaluate aging effects in these areas.

TVA Reply NRC RAI 3.0-10 LP

In a teleconference between TVA and the NRC staff on January 11, 2005, held to clarify the Staff's questions, it was agreed that a detailed description of the process used to establish the material condition of Unit 1 piping systems for restart would be sufficient in response to RAI 3.0-9 LP and RAI 3.0-10 LP. See the TVA Reply to NRC RAI 3.0-9 LP above for that description.

Regarding the Staff's question related to one-time inspections, TVA provides the following response:

The inspections described in TVA's response to NRC Request for Additional Information Related to Aging of Mechanical Systems During The Extended Outage dated October 8, 2004 would have been better characterized as "restart" inspections instead of an AMP "One-Time Inspection." Many inspections have been performed as part of the scoping effort for the Unit 1 restart process as described in the reply to RAI 3.0-9 above. These restart inspections are not intended to replace the one-time inspections required for license renewal. The one-time inspections will be performed in a time frame similar to Units 2 and 3. Additionally it is TVA's intention to require the same one-time inspections for Unit 1 as for Units 2 and 3, even though many of the piping systems in Unit 1 will be replaced with new material as part of the restart process. The Unit 1 license renewal inspections will be scheduled and conducted as required to support a timely implementation of the license renewal process.

NRC RAI 3.0-11 LP

The System Cleanliness Verification Program is not addressed in the LRA. NRC quarterly integrated inspection report

05000259/2004006 states that on March 22, 2004 the licensee decided to remove all Unit 1 systems from layup. This decision was based on the need to transition to a System Cleanliness Verification Program. On the basis of NRC quarterly integrated inspection report 05000259/2004007, this program is intended to replace the previous Equipment Layup Program that has been in place since the unit was shutdown. This report also stated that, under the new program, the assigned system and component engineers, along with chemistry personnel, would perform a series of inspections of Unit 1 systems to identify any system degradation or special requirements to support Unit 1 restart. Clarify if these series of inspections are part of the one-time inspection program that is going to be implemented prior to restart or in addition to the cleanliness verification program inspections. Also it is not clear that this system cleanliness verification program includes inspections on components that were replaced or repaired. Please provide information as to what type of inspections have been or are going to be performed by the System Cleanliness Verification Program.

TVA Reply to NRC RAI 3.0-11 LP

Inspections performed under the Cleanliness Verification Program (CVP) are not part of the one-time LRA inspections or credited as part of the license renewal application.

To facilitate Unit 1 restart activities, Unit 1 Systems have been removed from the layup program. It is not possible to maintain the layup program and perform the required field work needed for restart of Unit 1. The purpose of the CVP is to:

- Verify, through cleanliness verification of all internal and external surfaces of piping systems and metallic components, that the requirements for fluid (gas or liquid) system internal and external cleanliness are in accordance with TVA and industry standards,

- Provide the detailed remedial cleaning instructions for internal and external surfaces of piping systems and metallic components whose internal and external surface cleanliness does not meet respective cleanliness criteria as a result of extended layup, or work activity.

The CVP activities are applicable to all BFN Unit 1 steam, water, air, gas or oil piping systems and components which receive a formal return to service (RTS) in accordance with the BFN Unit 1 Restart Test Program System Preoperational Checklist

(SPOC). The only Unit 1 systems excluded from this program are those that are currently in service or have been in service supporting Units 2 and 3.

CVP inspections are performed to ensure internal and external system cleanliness and foreign material control program requirements are met. Visual inspections aided by boroscopes are performed to identify any remedial cleaning or flushing activities needed. If inspection reveals evidence of piping degradation, a problem evaluation report is initiated and entered into the corrective action program. An engineering evaluation is performed to ensure that the system is capable of operation through the extended period. The inspections performed by the CVP are not a part of the one-time license renewal application inspections, nor are they a part of the license renewal process.

Follow-up RAI to RAI 3.3-2 LP (Refer to new RAI 3.0-10 LP)

The response to RAI 3.3-2 LP stated that carbon steel piping and fittings, copper valves, copper heat exchanger (cooler) tubing, cast iron heat exchanger (cooler) head see the raw water environment during lay-up. It also mentioned that a sample of components with a raw water environment within the Control Rod Drive System (85) will be inspected for aging degradation by the One-Time Inspection Program. Raw water environment may be a likely detrimental environment for aging degradation for carbon steel, cast iron and copper-based components. NUREG 1801 XI.M32, one-time inspection, states that the AMP is an acceptable verification when either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. Clarify whether one-time inspection is appropriate to manage aging of carbon steel, cast iron and copper-based components in raw water environment during lay-up. Also provide the technical justification as to why one-time inspection is appropriate. If one-time inspection is not appropriate, then provide alternative appropriate aging management activities such as periodic inspection, with specific programmatic elements.

TVA Reply to Follow-up RAI to RAI 3.3-2 LP

Based on responses to NRC RAI 3.0-9 LP and NRC RAI 3.0-11 LP there is no need to perform an aging management program (AMP) “One-Time Inspection” on the components that were subjected to a raw water environment during lay-up. The inspections described in TVA’s response to RAI 3.3-2 would have been better characterized as “restart” inspections instead of an AMP “One-Time Inspection.” Once the Control Rod Drive System (85) is returned to service the components will have the same aging management programs applied to them as their current Unit 2 and 3 counterpart components.