TVA

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402-2801

November 1, 2011

10 CFR 50.90

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

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

Subject: **One-Time Inspection Procedure for BFN Units 1, 2 and 3**

References:

1. NRC Letter to TVA, "Issuance of Renewed Facility Operating License Nos. DPR-33, DPR-52, And DPR-68 for Browns Ferry Nuclear Plant, Units 1, 2, and 3 (TAC NOS. MC1704, MC1705, and MC1706)", dated May 4, 2006
2. Letter from TVA to NRC, "Browns Ferry Nuclear (BFN) Units 1, 2 and 3 License Renewal Application (LRA) – Revised Commitment List (TAC NOS. MC1704, MC1705, and MC1706)", dated April 21, 2006
3. NUREG-1843, "Safety Evaluation Report Related to the License Renewal of the Browns Ferry Nuclear Plant, Units 1, 2, and 3" April 2006

On May 4, 2006, the NRC issued Renewed Operating Licenses to the Tennessee Valley Authority (TVA) for BFN Units 1, 2, and 3 (Reference 1). As discussed in Reference 2 and reflected in Reference 3, TVA committed to develop a One-Time Inspection Procedure and provide this procedure to the NRC two years prior to the expiration of the current operating license.

In accordance with NUREG-1843, Browns Ferry One-Time Inspection Procedure (0-TI-565, Revision 3) is provided in the enclosure.

ADD1
NRR

There are no regulatory commitments associated with this letter. Please address any questions regarding this matter to Tom Hess at 423-751-3487.

Respectfully,

J. W. Shea

Enclosure:

Browns Ferry One-Time Inspection Procedure (0-TI-565, Revision 3)

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ENCLOSURE 1

One-Time Inspection Procedure for BFN Units 1, 2, and 3

Browns Ferry One-Time Inspection Procedure (0-TI-565, Revision 3)

TVA

Browns Ferry Nuclear Plant

Unit 0

Technical Instruction

0-TI-565

One-Time Inspection Procedure

Revision 0003

Quality Related

Level of Use: Reference Use

Effective Date: 09-15-2011

Responsible Organization: DEM, Design Eng Mech/Nuclear

Prepared By: Kathy L. Creamer, 256-614-6438

Approved By: Kevin L. Groom

Current Revision Description

Pages Affected: 5, 6, 22

Type of Change: Revision   Tracking Number: 004

Documentation: PER 412108

Revised note to RW1 of Appendix A for System 090 traps.

Added three definitions to 3.0.

Table of Contents

1.0 INTRODUCTION

1.1 Purpose

A. This procedure describes the One-Time Inspection (OTI) Program at Browns Ferry Nuclear Plant (BFN) to satisfy the requirements in Appendix O, Section 1.26, of the FSAR.

B. This procedure includes scoping, inspection point selection, inspection performance, documentation and evaluation of the inspection results and disposition of inspection anomalies.

1.2 Scope

A. The OTI Program applies to systems and components subject to aging management using the aging management programs for Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis and for which no aging effects have been observed or for which the aging effect is occurring very slowly and does not affect the component's or structure's intended function during the period of extended operation (PEO) based on prior operating experience data.

B. The OTI Program may also include other components and materials where the environment in the period of extended operation is expected to be equivalent to that in the prior 40 years and for which no aging effects have been observed.

2.0 REFERENCES

A. EPRI Report 1007933, "Aging Assessment Field Guide," December 2003

B. EPRI Report 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4," January 2006

C. NUREG-1801, Vol. 1, Rev. 0, 'Generic Aging Lessons Learned (GALL) Report - Summary," U.S. Nuclear Regulatory Commission, published April 2001

D. NUREG-1801, Vol. 2, Rev. 0, "Generic Aging Lessons Learned (GALL) Report - Tabulation of Results," U.S. Nuclear Regulatory Commission, published April 2001

E. EPRI Report 107514, "Age-Related Degradation Inspection (ARDI)"

F. FSAR Appendix O, Section O.1.26, One-Time Inspection

G. 10 CFR Part 54, Requirements for Renewal of Licenses for Nuclear Power Plants

H. NPG-SPP-03.1, Corrective Action Program

2.0 REFERENCES (continued)

I. NPG-SPP-07.0, Work Management

J. NPG-SPP-02.3, Operating Experience Program

K. TVA-NQA-PLN89-A, TVA Nuclear Quality Assurance Plan

L. N-VT-1, Visual Examination Procedure for ASME Section XI Preservice and Inservice

M. N-VT-14, Visual Examination to Detect Erosion/Corrosion Damage

N. IEP-200, "Qualification and Certification Requirements for TVA Nuclear Power Group (NPG) NDE Personnel"

O. MCI-0-000-PRP002, Surface Preparation for NDE (Nondestructive Examination)

P. N-UT-26, Ultrasonic Examination for the Detection of ID Pitting, Erosion, and Corrosion

Q. PER 333334, License Renewal OE Regarding Remote Visual Examinations

R. PER 333336, License Renewal OE Regarding UT Measurements of the Drywell Liner

3.0 DEFINITIONS

A. **Air/Gas** - Air/Gas environments include: air environments containing significant moisture such that condensation or water pooling may occur, atmospheric air (when internal to components), Carbon Dioxide, compressed air, exhaust gas from diesel generators, Freon, and Nitrogen.

B. **Aging Effect** - Aging effects are the results of various aging mechanisms which result in surface anomalies such as change in material properties/reduction in fracture toughness, cracking, elastomer degradation, fouling product buildup, and loss of material.

C. **Aging Mechanism** - Aging mechanism is a specific process that changes the characteristic of a material/component, with time or use, causing an aging effect.

D. **AMP** - Aging Management Program

E. **CASS** - Cast Austenitic Stainless Steel

F. **FSAR** - Final Safety Analysis Report

3.0 DEFINITIONS (continued)

G. **LR** - License Renewal

H. **LRA** - License Renewal Application

I. **MIC** - Microbiologically Influenced Corrosion

J. **MT** - Magnetic Particle Testing

K. **NDE** - Non-Destructive Examination

L. **PEO** - Period of Extended Operation

M. **PER** - Problem Evaluation Report

N. **PT** - Dye Penetrant Testing

O. **PV** - Performance Verification

P. **Raw or Potable Water** - Raw water is not demineralized or chemically controlled to any significant extent. Raw water includes water that enters the plant from the Wheeler Reservoir (Tennessee River) in which the water is rough filtered to remove large particles and biocides may be added to prevent fouling, water that enters the plant from the potable water system in which biocides may be added to make the water suitable for human consumption, and water that may be contaminated by impurities such as condensation and water in drainage and waste collection systems. Water beyond the chemical control boundaries of treated water systems. Examples include water in piping between double isolation valves; beyond isolation valves, vent valves, or drain valves; and transferred to sampling systems.

Q. **RE** - Responsible Engineer

R. **RP** - Radiation Protection

S. **RT** - Radiographic Testing

T. **SCC** - Stress Corrosion Cracking

U. **SER** - Safety Evaluation Report

V. **Treated Water** - Treated water is the base water for all clean systems. Treated water is demineralized water or chemically purified water. Treated water may have been injected with treatment chemicals in accordance with applicable chemistry control programs.

W. **UNID** - Unique Identifier

X. **UT** - Ultrasonic Testing

3.0 DEFINITIONS (continued)

Y. **VT** - Visual Inspection Testing

Z. **WO** - Work Order

4.0 GENERAL PRECAUTIONS

A. For OTI inspection point selection, review the available WO history or other plant records to provide reasonable assurance that components selected for inspection are representative of long-term exposure to the relevant conditions for aging. Components should not have been replaced within the 20 years prior to the PEO.

B. Use caution when using draft License Renewal (LR) boundary drawings. Selection of OTI points should be validated against the most current revision of the appropriate drawing(s).

C. Electrical, instrument, and mechanical craft work required to support the inspection program shall be requested and scheduled utilizing the WO process.

D. During inspections, should any personnel recognize a safety hazard, equipment malfunction, or other condition adverse to quality, they shall notify their supervisor/manager and document the condition in accordance with NPG-SPP-03.1, Corrective Action Program.

E. Inspection personnel shall comply with all applicable plant procedures and requirements such as safety, radiological controls, hold order tags, caution signs, etc., that are posted on plant equipment.

F. Inspection activities shall be coordinated using the Work Management Process in accordance with NPG-SPP-07.0, Work Management.

G. Inspection activities should be coordinated through the Unit Work Control supervisor, e.g., processing hold orders and craft, Operations, or RP support required for inspection activities.

H. Electrical, instrument, and mechanical craft activities shall be limited to work as identified in the approved work instruction. At no time will any work outside the scope of the authorized WO be permitted.

I. Inspection personnel shall exercise extreme caution when working around rotating, moving, or energized equipment. If equipment is **NOT** operating, personnel should be aware of the possibility of equipment automatically starting.

J. Inspection personnel should verify the material of the inspection location specified in the WO.

5.0 PREREQUISITES

A. The qualifications of the inspectors and the types of inspections required shall be identified.

B. Personnel involved with the field implementation of this procedure shall use NDE techniques and be qualified to perform VT inspections as specified in IEP-200, "Qualification and Certification Requirements for TVA Nuclear Power Group (NPG) NDE Personnel".

C. Before the inspection, involved team members shall be given a pre-job briefing in accordance with Browns Ferry pre-job brief expectations and the supervisor responsible for the inspection activity will ensure inspection team members are qualified to perform the inspection task.

D. For inspections in radiologically controlled areas, an As-Low-As-Reasonably-Achievable (ALARA) pre-plan may be necessary. The planner or job supervisor shall provide RP with the necessary information (e.g., RWP man-hours, high radiation area man-hours, etc.) during job walk down and WO review to determine if an ALARA pre-plan is required.

E. Coordination with scheduled maintenance and outage activities is highly recommended for ease of access to components located in plant areas **NOT** normally accessible during normal plant operation.

6.0 EQUIPMENT

Tools required for the inspections will be specified by the details in the WO.

7.0 PROCEDURE

7.1 Responsibilities

7.1.1 Director of Engineering

A. Responsible for establishing expectations for the support of and implementation of the OTI Program.

B. Ensures individuals are assigned to programs and tasks in support of the OTI Program.

C. Ensures training is developed and executed in support of the OTI Program and monitors training performance.

7.1.2 Mechanical Design Manager

A. Provides oversight of the OTI Program.

B. Assigns individuals and ensures resources are sufficient to successfully implement the OTI Program.

C. Ensure personnel assigned tasks possess the required training and qualifications by validating required qualifications and training periodically in the qualification database before assigning tasks.

D. Evaluate nuclear industry experience information in accordance with NPG-SPP-02.3, Operating Experience Program, and recommend changes in system design or operation, when appropriate.

7.1.3 OTI Program Owner

A. Maintain a copy of OTI Program Inspection records.

B. Provide oversight and technical direction of inspection and sampling activities.

C. Provide review and disposition of anomalies.

D. Ensure timely reporting of adverse conditions in accordance with NPG-SPP-03.1, Corrective Action Program.

E. Maintain records of all OTI inspections on the OTI Program Inspection plan, similar to Attachment 2.

7.1.4 Inspection Personnel

A. Perform and document inspection results using Attachment 1 or an approved equivalent.

B. Confirm material for inspection location.

C. Document actual inspection location and component type including component ID if applicable.

D. Provide the inspection data to the Program Owner.

E. Identify the need for additional engineering review of field anomalies.

F. Ensure timely reporting of adverse conditions in accordance with NPG-SPP-03.1, Corrective Action Program.

7.2 Scope Determination

A. The Program Owner (or designee) shall establish the total population of components and the aging effects for which the OTI Program is being credited from the BFN License Renewal Application (LRA), NRC Requests for Additional Information (RAIs) and the final Safety Evaluation Report (SER).

B. The Program Owner (or designee) shall organize all materials of construction and environments combinations into inspection groups such that those unique material and environmental combination groups become the total population size for that inspection group. Refer to Appendix A.

C. The sample size for each inspection group is determined based on 20 percent of the total sample population, with a maximum of 25 inspection locations for a group. Refer to Appendix A.

7.3 Select Inspection Locations

A. Using Appendix A for each inspection group, the Program Owner (or designee) shall review the associated system LR boundary drawings and select potential inspection points using the criteria for aging effects susceptibility.

1. Cracking (SCC and/or Cyclic Loading)
2. Elastomer Degradation (Oxidation and/or Thermal Exposure)
3. Fouling
4. Loss of Material
    a. Crevice Corrosion
    b. Galvanic Corrosion
    c. General Corrosion
    d. MIC
    e. Pitting Corrosion
5. Reduction in Fracture Toughness (CASS)

B. The Program Owner (or designee) shall build an Inspection Plan (similar to Attachment 2) using the potential locations identified for each system and the required sample size from Appendix A.

C. The Program Owner (or designee) shall select a representative sample of components from each inspection group identified in Appendix A and the following considerations:

7.3 Select Inspection Locations (continued)

1. Review on-line maintenance activities

2. Review work planned for refueling outages

3. Select inspections if no other opportunities exist

4. Spread the inspections between all three units with no less than 15 percent of the inspections on a single unit.

5. Accessibility, radiological concerns, and other outage activities

6. Propose maintenance and outage work orders so as to inspect components that are removed (as much as practical), in order to minimize the impact of the inspection on in-line components (and thereby, plant operations).

7. Review the available WO history or other plant records to provide reasonable assurance that components selected for inspection are representative of long-term exposure to the relevant conditions for aging. Components should not have been replaced within the 20 years prior to the PEO.

D. The Program Owner (or designee) shall build the Inspection Plan over the period prior to PEO until all inspections are complete.

E. The Program Owner (or designee) should choose inspection locations that are most susceptible to age-related degradation, based on review of plant procedures, drawings (e.g., flow diagrams) and plant/industry operating experience, for components in the sample population include:

1. Stagnant or low-flow locations are the most susceptible to degradation, with respect to cracking and loss of material, and typically occur in components such as:

    a. Portions of systems that are in layup/standby during normal plant operations.

    b. Dead end piping/tubing runs (e.g., normally isolated drain or vent lines/valves).

    c. Low points, such as drain lines/valves or drain traps.

2. Only locations where there is contact between dissimilar metals (e.g., carbon/alloy steel and copper alloy or stainless steel) are susceptible to a loss of material due to galvanic corrosion.

7.3 Select Inspection Locations (continued)

3. Heat exchanger tubes, cooling coils, and fins are susceptible to fouling (reduction of heat transfer) due to buildup of scale or other deposits.

4. Locations with elevated temperatures (typically above 140°F), such as upstream of a heat sink (heat exchanger) or downstream of a heat source, are the most susceptible to cracking of stainless steel due to stress corrosion cracking (SCC).

7.4 Define the Inspection

A. The Program Owner (or designee) shall initiate a WO for the inspection point.

B. The appropriate inspection method should be determined using Appendix B, including specific acceptance criteria (if any) for each location. Consider the following:

1. Cost, availability of personnel, accessibility of the component, expected condition/aging mechanism, etc.

2. Visual inspections (preferred) that identify degraded conditions may be supplemented by volumetric techniques, which can further quantify the extent of the aging effect.

C. The Program Owner (or designee) shall document each identified inspection location in the inspection plan along with the component number, method of inspection, basis for selection, and any specific acceptance criteria. The plan shall be verified early enough in outage preparations that scope changes can be adequately planned. Refer to Attachment 2 for an example inspection plan. The format may be adjusted at the discretion of the Program Owner.

1. Inspections may occur over the course of several outages and/or with the plant in normal operation.

2. The inspection plan should take advantage of opportunities for visual inspection (such as when opened for maintenance, repair or modification) as much as possible.

7.5 Conduct One-Time Inspections

A. The inspection WO will be scheduled through Outage Management or Daily Scheduling as appropriate.

B. The one-time inspections shall be performed by qualified personnel (the inspector), following procedures that are consistent with Section XI of the ASME B&PV Code and with 10 CFR 50, Appendix B, and using a variety of the non-destructive examination (NDE) techniques as described in Appendix B.

7.5 Conduct One-Time Inspections (continued)

C. The inspector shall perform and document the inspection in accordance with the WO.

D. The inspector shall include the inspection results in the WO and submit a copy to the Program Owner.

E. The Program Owner shall ensure that inspections not meeting the acceptance criteria are entered into the Corrective Action Program.

7.6 Documentation

A. Inspection findings will be documented on Attachment 1, Inspection Data Sheet(s), or an approved equivalent.

B. All completed inspection records will be reviewed by the Program Owner and documented on the inspection plan.

C. The Program Owner shall review and disposition each unacceptable finding submitted on the Inspection Data Sheet.

D. Completed data packages will be sent to Records Management as part of the WO package.

7.7 Evaluation

A. The Program Owner (or designee) shall perform an initial review of one-time inspection data from inspected components, as it is received.

1. Ensure that the data is for the correct component and that documentation is complete (e.g., contains adequate description of findings). Any inspection data that is incomplete or inaccurate shall be re verified by the inspector.

2. Perform the initial review as soon as possible after receipt of the inspection results (prompt review may ensure that the component is still accessible for verification, if needed).

3. All visual indications of surface anomalies shall be documented in a PER and are subject to evaluation by the Program Owner.

B. The Program Owner (or designee) shall compile and review all inspection data for each material/environment combination to:

1. Determine if any identified degradation is related to normal aging of the component or to other considerations.

7.7 Evaluation (continued)

2. If degradation is related to the normal aging of the component, then subsequent evaluation is appropriate to evaluate the rate of aging and if the aging rate requires either additional monitoring or other actions within the PEO.

3. If degradation/condition is **NOT** related to normal aging (e.g., is due to a design issue, such as cavitation, or to a unique event), then evaluate the condition and determine the appropriate action to either monitor or correct the condition.

7.8 Corrective Actions

A. The engineering evaluation of inspection results, performed in accordance with NPG-SPP-03.1, Corrective Action Program, to ensure that the intended functions of the components within the scope of this procedure can be maintained consistent with the current licensing basis.

B. If the engineering evaluation concludes that age-related degradation is occurring and could result in loss of component function during the period of extended operation, the unacceptable condition is documented in the corrective action program. "Aging management" should be included in the Service Request description to ensure proper trending of aging management issues. Required corrective actions may include further analytical evaluation, repair, component replacement, or establishing a program to periodically monitor and trend the identified degradation.

C. If no degradation is detected or engineering evaluation concludes that component intended function would **NOT** be lost during the period of extended operation, no further inspections or periodic activities are needed.

7.9 Report of the Inspection Results

A. The Program Owner (or designee) shall assemble all Data Sheets and Problem Evaluation Reports for each material/environment combination described in Appendix A for each operating unit.

B. The Program Owner (or designee) shall prepare a One-Time Inspection report to document the related activities and conclusions.

C. The Program Owner (or designee) shall submit the completed package to Records Management (RM).

8.0 ACCEPTANCE CRITERIA

A. Any indication of degradation.

8.0 ACCEPTANCE CRITERIA (continued)

B. Any evidence of localized corrosion such as crevice, pitting, or galvanic (at dissimilar metal interfaces) corrosion, or of cracking (due to SCC or cyclic loading).

C. Any evidence of general (uniform) corrosion.

D. Any evidence of the relevant conditions for MIC (e.g., presence of sulfate-reducing bacteria).

E. Any evidence of a fouling layer on the tubes of heat exchangers/coolers, or loss/reduction of the heat transfer capability.

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Inspection Groups

Date ________

Inspection Group	Environment	Material	Affected Systems			Estimated Total Population (3 Units)	Number of Required Inspections (3 Units)	Aging Effects Requiring Management
AG1	Air/Gas	Non-ferrous	012 031 053 064 067			>125	25	Cracking, Fouling, Loss of Material
AG2	Air/Gas	Steel	001 002 003 010 012 023 024 025 026 027 029 030 031	033 037 040 043 053 063 064 065 066 067 068 069 070	071 073 074 075 076 077 078 082 084 085 086 090 RV	>125	25	Cracking, Loss of Material

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Inspection Group	Environment	Material	Affected Systems	Estimated Total Population (3 Units)	Number of Required Inspections (3 Units)	Aging Effects Requiring Management
AG3	Air/Gas	Elastomer	082 086	88	18	Degradation due to Thermal Exposure
AG4	Air/Gas	Stainless Steel	003 012 031 072 084	>125	25	Cracking (003 only), Fouling (031 and 084 only), Loss of Material, Reduction in Fracture Toughness (003 only)
FO1	Fuel Oil	Non-ferrous	018	>125	25	Loss of Material (MIC only)
FO2	Fuel Oil	Steel	018	>125	25	Loss of Material
FO3	Fuel Oil	Elastomer	018	16	4	Degradation due to Oxidation
FO4	Fuel Oil	Stainless Steel	018	16	4	Loss of Material (MIC only)
LO1	Lubricating Oil	Steel	077 082	41	9	Loss of Material
LO2	Lubricating Oil	Copper Alloy	077 082	33	7	Loss of Material

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Inspection Group	Environment	Material	Affected Systems	Estimated Total Population (3 Units)	Number of Required Inspections (3 Units)	Aging Effects Requiring Management
RW1	Raw Water	Non-ferrous	029 031 090	>125	25	Cracking (090 only), Fouling (031 only), Loss of Material
RW2	Raw Water	Steel	027 029 031 050 077	>125	25	Loss of Material
RW3	Raw Water	Stainless Steel	029 031 050 068 077	>125	25	Fouling (031 only), Loss of Material
TW1	Treated Water	Non-ferrous	002 044 074 012 063 075 023 068 077 026 069 078 037 071 085 043 073	>125	25	Cracking, Fouling (071 and 073 only), Loss of Material

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Inspection Group	Environment	Material	Affected Systems	Estimated Total Population (3 Units)	Number of Required Inspections (3 Units)	Aging Effects Requiring Management
TW2	Treated Water	Steel	001, 002, 003, 006, 008, 010, 012, 023, 037, 043, 044, 063, 064, 066, 068, 069, 071, 073, 074, 075, 077, 078, 085	>125	25	Cracking, Loss of Material
TW3	Treated Water	Stainless Steel	001, 002, 003, 010, 023, 043, 063, 064, 068, 069, 071, 072, 073, 074, 075, 077, 078, 085, 092	>125	25	Cracking, Fouling (074 only), Loss of Material
Submerged	Treated Water	Steel, Stainless Steel	N/A	See note below for Submerged.	See note below for Submerged.	Loss of Material

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Note 1: Number of inspections required is 20% of the total population but not greater than 25.

AG1 - Within scope there are 15 coolers in System 064, 52 in System 031, and 3 in System 067. Non-ferrous alloys include aluminum and copper alloys. Each of the coolers has copper alloy cooling coils and aluminum alloy fins that are exposed to the air/gas environment. There are also 2 copper alloy traps in System 053 and 1 copper alloy valve in System 012. Therefore, the total population for AG1 is greater than 125.

Crack initiation/growth due to stress corrosion cracking (SCC) was identified as an aging effect requiring management in the air/gas environment only in System 031, and only for the aluminum alloy fins.

Loss of material includes the following mechanisms: crevice, pitting, and galvanic corrosion. Galvanic corrosion was identified as an aging effect requiring management in the air/gas environment only in System 012, and only for the joints between a bronze isolation valve for flow element FE-12-77 and the stainless steel instrumentation piping.

AG2 - Within scope, steel (carbon and low-alloy steel, cast iron and cast iron alloys) exposed to the air/gas environment is a common material/environment combination in 39 systems, including the Reactor Vessel. Therefore, a total population of greater than 125 is a reasonable estimate for AG2.

Loss of material includes the following mechanisms: crevice, galvanic (dissimilar metal contact), general, and pitting corrosion.

AG3 - The only elastomers within scope that are exposed to the air/gas environment are flexible connectors/hoses in the diesel systems, System 082 and System 086. A review of System Reports and boundary drawings reveals that there are 6 for each of 4 diesels on Unit 0 System 082, and 12 for each of 4 diesels on Unit 3 System 082. There are 2 for each of 4 diesels on Unit 0 System 086, and 2 for each of 4 diesels on Unit 3 System 086. Therefore, the total population for AG3 is 88.

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AG4 - Within scope, stainless steel exposed to the air/gas environment is a common material/environment combination in 5 systems. Stainless steel includes nickel alloys. Therefore, a total population of greater than 125 is a reasonable estimate for AG4.

Crack initiation/growth due to cyclic loading and SCC were identified as aging effects requiring management for stainless steel in the air/gas environment of only one system, System 003 (cyclic loading is only for components that are within the reactor coolant pressure boundary (RCPB).

Fouling product buildup due to particulate was identified as an aging effect requiring management only for stainless steel heat exchanger tubes in the air/gas environment of 2 systems, System 031 and System 084. A review of the System Reports and boundary drawings reveals that there are 6 such heat exchangers per Unit in System 031, and a total of 2 for System 084.

Loss of material includes the following mechanisms: crevice and pitting corrosion.

FO1 and FO2 - There is only one system within the scope of the One-Time Inspection Program with a fuel oil environment, i.e., System 018. Common component types such as fittings, piping, tubing, and valves, have been identified as non-ferrous metal alloys (aluminum alloys and copper alloys), and steel (carbon steel and cast iron). With hundreds of such components within the scope of the One-Time Inspection Program, a total population of greater than 125 is a reasonable estimate for each of these inspection groups.

Loss of material includes the following mechanism for all components: microbiologically influenced corrosion (MIC). For tanks, loss of material also includes crevice, general and pitting corrosion.

FO3 - There is only one system within scope with a fuel oil environment, i.e., System 018, and the only elastomer components are flexible hoses. A review of the System Report and boundary drawings reveals that there are 2 for each of 4 diesels on Unit 0 System 018, and 2 for each of 4 diesels on Unit 3 System 018. Therefore, the total population for FO3 is 16.

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FO4 - There is only one system within scope with a fuel oil environment, i.e., System 018, and the only stainless steel components are associated with 4 pressure indicators, one each on the suction and discharge sides of the two fuel oil transfer pumps. Components include piping, tubing and valves. Therefore, the total population for FO4 is estimated at 20.

Loss of material includes the following mechanisms: MIC.

LO1 - There are only two systems within scope with a lubricating oil environment, i.e., System 077 and System 082. For System 077, a review of the System Report and boundary drawings reveals that only 3 piping segments, 2 valves, and associated fittings (estimated as 4 times the number of piping segments and valves, for a total of 20 fittings) are identified. For System 082, only strainers (2 for each of 8 diesels, for a total of 16) are identified. Therefore, the total population for LO2 is 41.

Loss of material includes the following mechanisms: crevice and pitting corrosion.

LO2 - There are only two systems within scope with a lubricating oil environment, i.e., System 077 and System 082. For System 077, a review of the System Report and the boundary drawings reveals that only one component is identified, i.e., valve 0-77-1352. For System 082, only tubing and valves (2 of each for each of 8 diesels, for a total of 32) are identified. Therefore, the total population for LO2 is 33.

Loss of material includes the following mechanisms: crevice, galvanic (dissimilar metal contact), general, and pitting corrosion.

RW1 - The System 031 copper alloy cooling coils that are identified in group AG1 have raw water as the internal environment of the tubes. In addition, there are copper alloy tubing, valves, and associated fittings in the raw water supply and return lines for these cooling coils; and numerous copper alloy valves and fittings in System 029, which supplies cooling water to some of these cooling coils. There are also aluminum traps in System 090 exposed to raw water. Therefore, a total population of greater than 125 is a reasonable estimate for RW1.

Crack initiation/growth due to SCC was identified as an aging effect requiring management in the raw water environment only for the aluminum traps in System 090.

Fouling product buildup due to particulate was identified as an aging effect requiring management only for copper alloy heat exchanger tubes (cooling coils) in the raw water environment of System 031. As described in AG1 above, there are 52 such cooling coils.

Loss of material includes the following mechanisms: crevice, galvanic, and pitting corrosion.

RW2 - Within scope, steel exposed to the raw water environment is a common material/environment combination in 4 systems. Therefore, a total population of greater than 125 is a reasonable estimate for RW2.

Loss of material includes the following mechanisms for all components: crevice, galvanic, general, and pitting corrosion. For System 050 and System 077, loss of material also includes biofouling and MIC.

RW3 - Within scope, stainless steel exposed to the raw water environment is a common material/environment combination in 4 systems. Therefore, a total population of greater than 125 is a reasonable estimate for RW3.

Fouling product buildup due to particulate was identified as an aging effect requiring management only for stainless steel heat exchanger tubes in the raw water environment of System 031. A review of the System Report and boundary drawings reveals that there are 6 such heat exchangers per Unit in System 031.

Loss of material includes the following mechanisms for all components: crevice and pitting corrosion. For System 050 and System 077, loss of material also includes biofouling and MIC.

TW1 - Within scope, non-ferrous metal alloys exposed to the treated water environment is a common material/environment combination in 17 systems. Therefore, a total population of greater than 125 is a reasonable estimate for TW1.

Fouling product buildup due to particulate was identified as an aging effect requiring management only for copper alloy heat exchanger tubes in the treated water environment of 2 systems. A review of the System Reports and boundary drawings reveals that there is one such heat exchanger per system per unit. Therefore, the total population for TW1b is 6.

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Loss of material includes the following mechanisms: crevice, galvanic, and pitting corrosion.

TW2 - Within scope, steel exposed to the treated water environment is a common material/environment combination in 23 systems. Therefore, a total population of greater than 125 is a reasonable estimate for TW2.

Loss of material includes the following mechanisms: crevice, galvanic, general, and pitting corrosion.

TW3 - Within scope, stainless steel exposed to the treated water environment is a common material/environment combination in 19 systems. Therefore, a total population of greater than 125 is a reasonable estimate for TW3.

Fouling was identified as an aging effect requiring management for stainless steel components exposed to treated water in only one system, System 074. A review of the System Report and boundary drawings reveals that, for each Unit, there are 4 RHR heat exchangers and 4 RHR pump seal water heat exchangers with stainless steel tubes in System 074.

Loss of material includes the following mechanisms: crevice and pitting corrosion.

Submerged - This inspection group consists of the ASME equivalent Class MC supports submerged in the torus (pressure suppression chamber), which are evaluated as exposed to a treated water environment. The population is the accessible portions of 16 ring girder supports and 48 down comer tie bar supports. The number of required inspections is 25% of the population, or 4 ring girders and 12 down comer tie bar supports on Unit 2 and 4 ring girders and 12 down comer tie bar supports on Unit 3.

Loss of material includes the following mechanisms: crevice, general, and pitting corrosion.

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Inspection Methods

Examples of Parameters Monitored or Inspected And Aging Effect for Specific Structure or Component[1]			
Aging Effect	**Aging Mechanism**	**Parameter Monitored**	**Inspection Method[2]**
Loss of Material	Crevice Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Galvanic Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	General Corrosion	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	MIC	Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)
Loss of Heat Transfer	Fouling Buildup / Particulate	Tube/Fin Fouling	Visual (VT-3 or equivalent) or Enhanced VT-1 for CASS
Cracking	SCC or Cyclic Loading	Cracks	Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT)

1 NUREG-1801 XI.M32 One-Time Inspection

2 Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

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1.0 VISUAL INSPECTION (VT)

A. Most one-time inspections will be conducted using visual examination techniques. This section provides specific information for visual examinations and incorporates the applicable sections of TVA procedure N-VT-1 to provide guidance for the inspectors.

B. Personnel performing visual examinations shall be certified in accordance with IEP-200 [Reference N], or a written practice approved by TVA. Level-I personnel may perform examinations only under the guidance of a Level-II or Level-III individual.

C. General Requirements:

1. Illumination and resolution requirements shall be considered adequate based on the following table for procedure qualification and demonstration:

Table C.1

Visual Examination	Minimum Illumination	Maximum Direct Exam Distance, Feet	Maximum Resolvable Lower Case Character Height
VT-1	50 fc	2	0.044-inches
VT-3	50 fc	N/A	0.105-inches
VT-1 Enhanced	Note	2	1 mil. Wire

a. For the procedure demonstration (VT-1 / VT-3), a near distance vision test chart containing text with lower case characters, without an ascender or descender, containing the correct heights shall be resolved at the distances and illumination levels specified in Table C.1. The lighting source for the above demonstration shall be verified.

b. The illumination levels shall be checked before and after each field examination or series of examinations, not to exceed 4 hours when battery powered portable lighting is used by resolving the applicable characters on the Visual Illumination Card (VIC) the maximum examination distance applied, not to exceed the distance specified in Table C.1. As an alternative to the VIC, minimum illumination levels specified in Table C.1 may be verified with a light meter. Illumination verification checks shall be noted on the report.

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1.0 VISUAL INSPECTION (VT) (continued)

c. The illumination levels shall be verified before each field examination when ambient (not battery powered) lighting is used by resolving the applicable characters on the VIC at the maximum examination distance applied, not to exceed the distance specified in Table C.1. As an alternative to the VIC, minimum illumination levels specified in Table C.1 may be verified with a light meter. Illumination verification checks shall be noted on the report.

d. Remote visual examinations may use visual aids such as mirrors, telescopes, boroscopes, fiber optics, video scopes, cameras, or other suitable instruments. Such systems shall have a resolution capability and color discrimination ability at least equivalent to that obtainable by direct visual observation. The parameters established for the remote visual device demonstration (i.e. actual viewing distance, resolution, monitors, etc.) shall be the parameters used for the remote examination.

e. If a boroscope is used, Character Card calibrations in the same plane as the boroscope shall be used (i.e., parallel or perpendicular to the boroscope). Ensure that examination record sheets contain proper reference to the Character Card and inspection angle. [PER 333334]

NOTE: The Enhanced Visual examination is applicable to specific applications (i.e., VT of inner radius areas in lieu of UT). The illumination levels shall be verified before and after each field examination or series of examinations by resolving the 1 mil wire at or near the area of examination at the maximum distance applied not to exceed the distance specified in Table C.1 and using the applicable light source necessary to obtain the required resolution (i.e., flashlight, ambient, etc.).

2. The license renewal visual examinations are typically performed when the piping system is open (such as during maintenance, repair or modification) and components are accessible for visual examination of the internal surfaces.

3. Examinations shall be documented on an appropriate form meeting the required attributes. Generic forms are shown in Attachments 1 and 3. Other forms that list the required attributes may be used.

4. Examinations that reveal adverse conditions not meeting the acceptance criteria shall be reported to the Program Owner.

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1.0 VISUAL INSPECTION (VT) (continued)

5. Conditions that cannot be easily recorded on the appropriate data form shall be sketched or photographed in order to record the conditions accurately.

6. Examinations that identify degraded conditions outside the recording requirements (e.g., flaws located outside the required examination area) of this procedure shall be reported to the Program Owner.

D. VT-1 Examination Method:

1. The VT-1 visual examination shall be conducted to determine the condition of the part, component, or surface examined by detecting degradation from such conditions as cracks, wear, corrosion, erosion or physical damage on the examination surface.

2. The VT-1 visual examination may be performed by the direct or remote visual examination methods or a combination thereof.

3. Examinations that detect crack-like indications may be supplemented by either surface or volumetric examinations to determine the size, shape, and orientation of the suspected flaw.

4. Direct VT-1 visual examinations may be performed when access is sufficient to place the eye within 2-feet of the surface to be examined and at an angle not less than 30 degrees to the surface to be examined. Mirrors may be used to improve the angle of vision, and aids such as a magnifying lens may be used to assist examinations.

5. Remote examinations may be substituted for direct examination provided the system has resolution capabilities equivalent to that attainable by the direct visual of Table C.1. Optical aids, such as those described in paragraph C.1.d above may be used for the examination. When using Remote Visual Examination techniques, the following shall be documented:

   - The type of remote equipment used for the exam (See paragraph C.1.d above for demonstration requirements).
   - The maximum demonstration distance utilized in paragraph C.1.
   - Pre and post examination resolution verification times.

6. Lighting, natural or artificial, shall be as required in paragraph C.1.

1.0 VISUAL INSPECTION (VT) (continued)

E. VT-3 Examination Method:

1. The VT-3 visual examination shall be conducted to determine the general condition of the part, component, or surface examined by detecting degradation from such conditions as corrosion, wear, erosion, Microbiological Induced Corrosion (MIC), fouling buildup or physical damage on the examination surface.

2. Examinations that detect crack-like indications shall be supplemented by either surface or volumetric examinations to determine the size, shape, and orientation of the suspected flaw.

3. Direct VT-3 Visual Examination may be performed when access is sufficient to meet the illumination and resolution requirements of Table C.1. Mirrors may be used to aide in the examination.

4. Remote examinations may be substituted for direct examination provided the system has resolution capabilities equivalent to that attainable by the direct visual of Table C.1. Optical aids, such as those described in paragraph C.1.d above may be used for the examination. When using Remote Visual Examination techniques, the following shall be documented:

   - The type of remote equipment used for the exam (See paragraph C.1.d above for demonstration requirements).
   - The maximum demonstration distance utilized in paragraph C.1.
   - Pre and post examination resolution verification times.

5. Lighting, natural or artificial, shall be as required in paragraph C.1.

F. Personnel conducting VT's shall transmit all visual inspection results, including any sketches or photographs, as follows:

1. To the Program Owner (or designee), for initial evaluation.

2. To the WO for permanent retention.

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2.0 OTHER METHODS

A. Other acceptable and accurate inspection methods, which are current at the time of inspection, may be used at the discretion of the Program Owner, for example:

1. Ultrasonic (UT) or radiographic (RT) testing. Note that RT is usually used only on small-bore and socket-welded piping and poses a radiological safety hazard which must be considered.

2. Performance testing, heat transfer testing, or other accepted tests for heat exchangers/coolers may be required to determine the extent of fouling and its impact on heat transfer during the period of extended operation.

3. Magnetic particle (MT) or dye penetrant (PT) testing may be used to detect cracking.

4. Collection and laboratory testing of bacteria (e.g., sulfate-reducing) may be needed to determine the extent of MIC.

B. Other inspection methods shall be performed by qualified personnel and shall be documented on the applicable NDE data sheet, or an approved equivalent.

C. If UT is used to detect wall-thinning, cracking, or pitting corrosion, the WO shall require a sign-off that surface preparation is satisfactory (SAT), or prepared in accordance with MCI-0-000-PRP002. [PER 333336]

D. Personnel conducting other inspection methods shall transmit all inspection results, including any sketches or photographs, as follows:

1. To the Program Owner (or designee), for initial evaluation.

2. To the WO for permanent retention.

Appendix C
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Aging Effect Appearance and Characteristics

Aging Effect and Mechanism	Appearance and Characteristics
Change in Material Properties/Reduction in Fracture Toughness due to Thermal Aging	Increased yield and tensile strength Decreased ductility Degradation of toughness properties
Cracking due to Cyclic Loading	Brittle-appearing fracture of a normally ductile alloy in the presence of an environment that causes minimal uniform corrosion
Cracking due to Stress Corrosion Cracking	Highly localized form of corrosion Brittle-appearing fracture of a normally ductile alloy in the presence of an environment that causes minimal uniform corrosion Transgranular Often initiated at pits or other discontinuities Crack growth progresses across the metal grain without regard to grain boundary Intergranular Initiated at areas of intergranular corrosion attack, pitting, or other discontinuities Crack growth progresses along the grain boundaries
Elastomer Degradation due to Oxidation	Embrittlement, reduced tensile strength, reduced elongation limit, increased stiffness, increased hardness

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Aging Effect Appearance and Characteristics

Aging Effect and Mechanism	Appearance and Characteristics
Elastomer Degradation due to Thermal Exposure	Oxidation of polymer - Embrittlement, discoloration, crazing, reduced elongation limit Migration of additives and processing aids - Embrittlement, discoloration, surface film, reduced elongation limit, increased hardness Water solubility increase - Volume loss, wrinkling Conductivity increase - Signal degradation, increased dielectric losses, decreased capacitance Molecular weight decrease - Reduced tensile strength, reduced elongation limit, reduced hardness, decreased creep resistance Softening (sulfur-cured polymers) - Reduced tensile strength, decreased hardness, reduced creep strength Creep damage - Localized or overall distortion
Fouling Product Buildup due to Particulate	Buildup of deposits on heat exchanger components
Loss of Material due to Biofouling	Corrosion caused by the attaching of animal and plant life to solid surfaces
Loss of Material due to Crevice Corrosion	Similar to pitting, but occurs in crevices created by equipment geometry Rate partially depends on crevice geometry and dimensions Autocatalytic in nature once initiated Failure occurs eventually by pitting propagation or stress corrosion cracking
Loss of Material due to Galvanic Corrosion	Corrosion of one metal joined to another that remains undamaged
Loss of Material due to General Corrosion	Uniform, regular removal of metal over entire surface of structure Uniform thinning of metal

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(Page 3 of 3)

Aging Effect Appearance and Characteristics

Aging Effect and Mechanism	Appearance and Characteristics
Loss of Material due to Microbiologically Induced Corrosion	Presence of bacteria known to induce corrosion (Note: Presence of microbes is not an exclusive indicator of MIC.) Heavy surface deposits or tubercles Severe corrosion of materials in solutions to which they are normally resistant Moderate to severe occlusion of pipe, heavy surface deposits on tank walls Undulating, non-uniform surface Foul odor often present Slimy feel
Loss of Material due to Pitting Corrosion	Localized corrosion attack of otherwise unaffected base metal Results from the failure of a passive film or localized impurities Small relative to total exposed area Self-propagating in nature once initiated Difficult to detect or to predict, but very destructive

Attachment 1
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Inspection Data Sheet

Component Data

Component ______________________

Unit ______ System ______ Component ID (if applicable) ____________

Component Type ______________________

Component/Location Description ____

Corresponding Flow Diagram/Coordinates ____

Material/Environment (e.g. Carbon Steel/Treated Water) ______________________________

Inspection Grouping/Chemistry Regime ____

Inspection Data

Inspection Method (VT, UT, RT, other) ____

Degradation Detected (Yes or No) __________

Description of Degradation (if any) ____

Change in Material Properties/Reduction in Fracture Toughness	YES☐	NO☐
Cracking	YES☐	NO☐
Elastomer Degradation	YES☐	NO☐
Fouling Product Buildup	YES☐	NO☐
Crevice Corrosion	YES☐	NO☐
Galvanic Corrosion	YES☐	NO☐
General Corrosion	YES☐	NO☐
Microbiologically Influenced Corrosion	YES☐	NO☐
Pitting Corrosion	YES☐	NO☐

Comments (e.g., description of surface condition, reference for any photographs taken)

____

____

____

Examiner: ______________________________ Date________

Program Owner Review: ____________________ Date________

Attachment 2
(Page 1 of 1)

One-Time Inspection - Information/Results

Unit _____ **Page ______**

Inspection Location			Relevant Conditions				Job Description				Results	
System (No.)	Flow Diagram	Location / UNID	Material	Environment	Inspection Group	Basis for Selection	WO	Inspection Type / Method	Inspector Qualifications	Acceptance Criteria	AC Met (Y/N)	Resulting PER

Attachment 3
(Page 1 of 1)

Typical Tennessee Valley Authority Record of Visual Examination

RECORD OF VISUAL EXAMINATION

EXAM DATE: ________ PROCEDURE: 0-TI-565, REV: ________ REPORT NUMBER: ________

PLANT: ________ UNIT: ________ CYCLE: ________

COMPONENT ID: ________ SYSTEM: ________

DRAWING NO: ________ VISUAL AID(S): ________

COMPONENT TYPE: PUMP ☐ VALVE ☐ PIPING ☐ TANK ☐ DUCTWORK ☐ TUBING ☐

TYPE OF VISUAL EXAM: EVT-1 ☐ VT-1 ☐ VT-3 ☐ DIRECT ☐ REMOTE ☐ LICENSE RENEWAL ☐

ILLUMINATION CHECK ADEQUATE: ☐ VISUAL CARD S/N: ________

REMARKS:

Examination Resolution Verification Times: ________ (Initial) ________ (Final) ________

Maximum Demonstration Distance: ________

WORK ORDER NUMBER: ________

EXAMINER: ________ LEVEL: ________ DATE: ________

EXAMINER: ________ LEVEL: ________ DATE: ________

REVIEWER: ________ LEVEL: ________ DATE: ________

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