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18.0 Aging Management Programs and Activities

Paragraph(s) Deleted Per 2000 Update.

Aging Management Programs and Activities are being implemented as of July 1, 2001.

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18.1 Introduction

As the current operating license holder for Oconee Nuclear Station, Duke Energy Corporation prepared an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application) [Reference 1]. The application, including information provided in additional correspondence, provided sufficient information for the NRC to complete their technical and environmental reviews and provided the basis for the NRC to make the findings required by Section 54.29 (Final Safety Evaluation Report - Final SER) [Reference 2]. Pursuant to the requirements of Section 54.21(d), the UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by Section 54.21 (a) and (c), respectively.

As an aid to the reader, Table 18-1 provides a summary listing of the programs, activities and time-limited aging analyses (TLAA) (topics) required for license renewal. The first column of Table 18-1 provides a listing of these topics. The second column of Table 18-1 indicates whether the topic is a Program/Activity or TLAA. The third column of Table 18-1 identifies where the description of the Program, Activity, or TLAA is located in either the Oconee UFSAR or in the Oconee Improved Technical Specifications (ITS).

Section 18.2 contains summary descriptions of the one-time inspections that have been committed to be performed prior to the period of extended operation. Section 18.3 contains summary descriptions of the aging management programs and periodic inspections that are ongoing through the duration of the operating licenses of Oconee Nuclear Station. Section 18.4 contains additional commitments that are not identified in the preceding sections of Chapter 18.

A grace period may be applied to the frequencies of inspections required by aging management programs that existed at the time of the NRC license renewal review as documented in the license renewal safety evaluation (NUREG 1723). The grace period must be consistent with what applied when the NRC reviewed and approved the program. The NRC's review, as documented in NUREG 1723, confirmed that existing programs and inspection frequencies were adequate based on operating experience; therefore, whatever grace period that applied during the NRC review can be applied going forward. A grace period may not be applied to the frequencies of inspections of new aging management programs until adequate operating experience is obtained.

Station documents will be established, implemented, and maintained to cover the aging management programs and activities described in Chapter 18.

18.1.1 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

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18.2 One-Time Inspections for License Renewal

18.2.1 Cast Iron Selective Leaching Inspection

Purpose - The purpose of the Cast Iron Selective Leaching Inspection will be to characterize loss of material due to selective leaching of cast iron components in Oconee raw water, treated water, and underground environments.

Scope - The results of this inspection will be applicable to the cast iron components falling within the scope of license renewal. These components include pump casings in several systems along with piping, valves and other components. The Oconee raw and treated water systems containing cast iron components potentially susceptible to loss of material due to selective leaching are the Auxiliary Service Water System, the Low Pressure Service Water System, the Condenser Circulating Water System, the Service Water System (Keowee), the Chilled Water System, the Condensate System, and the High Pressure Service Water System. Note: The Auxiliary Service Water System has been replaced by the Protected Service Water System. The Auxiliary Service Water pump was one of the selected pumps inspected; hence, reference to the Auxiliary Service Water System is correct for this program.

Aging Effects - The inspection will determine the existence of loss of material due to selective leaching, a form of galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Method - The Cast Iron Selective Leaching Inspection will inspect a select set of cast iron pump casings to determine whether selective leaching of the iron has been occurring at Oconee and whether loss of material due to selective leaching will be an aging effect of concern for the period of extended operation. A Brinell Hardness check will be performed on the inside surface of a select set of cast iron pump casings to determine if this phenomenon is occurring. The results of the Cast Iron Selective Leaching Inspection will be applicable to all cast iron components within license renewal scope and installed in applicable environments.

Sample Size - A representative sample of six pump casings will be inspected for evidence of selective leaching, one from each of the following systems on-site:

1. Auxiliary Service Water System

   Note: The Auxiliary Service Water System has been replaced by the Protected Service Water System. The Auxiliary Service Water pump was one of the selected pumps inspected; hence, reference to the Auxiliary Service Water System is correct for this program.
2. Chilled Water System
3. Low Pressure Service Water System
4. High Pressure Service Water System
5. Service Water System (Keowee)
6. Condensate System (one inspection location on any of the three Oconee Units.)

Industry Codes or Standards - No specific codes or standards exist to address this inspection.

Frequency - The Cast Iron Selective Leaching Inspection is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to selective leaching as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Corrective Action - Any unacceptable loss of material due to selective leaching requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Problem Investigation Program. The Problem Investigation Program will apply to all structures and components within the scope of the Cast Iron Selective Leaching Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.2 Galvanic Susceptibility Inspection

Purpose - The purpose of the Galvanic Susceptibility Inspection will be to characterize the loss of material by galvanic corrosion in carbon steel - stainless steel couples in the Oconee raw water systems.

Scope - The results of this inspection will be applicable to all galvanic couples with the focus on the carbon steel - stainless steel couples in the Oconee raw water systems falling within the scope of license renewal.

Aging Effects - The inspection will determine the existence of loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function.

Method - A volumetric or destructive examination at the junction of the carbon steel - stainless steel components will be performed to determine material loss from the more anodic carbon steel. The most susceptible locations will be identified. The exact method of examination will be determined at the time of the inspection.

Sample Size - A sentinel population of the more susceptible locations on all three Oconee units, Keowee, and Standby Shutdown Facility will be selected for this inspection from the following raw water systems within the scope of license renewal.

1. Auxiliary Service Water System

   Note: The inspection of the Auxiliary Service Water System piping was completed prior to upgrading the system to the Protected Service Water System.

2. Chilled Water System (raw water portion of the chillers)
3. Component Cooling System (raw water portion of the Component Cooler)
4. Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal)
5. Condenser Circulating Water System
6. Diesel Jacket Water Cooling System (raw water portion of the jacket water heat exchanger)
7. High Pressure Service Water System
8. Low Pressure Injection (raw water portion of the Decay Heat Removal Cooler)
9. Low Pressure Service Water System

10. Service Water System (Keowee)
11. Standby Shutdown Facility Auxiliary Service Water System
12. Turbine Generator Cooling Water System (Keowee)
13. Turbine Sump Pump System (Keowee)

Areas of low flow to stagnant conditions in Oconee raw water systems which contain carbon steel - stainless steel couples are the most susceptible locations. Engineering practice at Duke has been to use stainless steel as a replacement material in raw water systems for several years. Since engineering practice will continue to use stainless steel as an acceptable substitute material, the size of the sentinel population will be dependent on the number of susceptible locations at the time of the inspection.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Frequency - The Galvanic Susceptibility Inspection is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to galvanic corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss due of material due to galvanic corrosion requires that an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Problem Investigation Program. The Problem Investigation Program will apply to all structures and components within the scope of the Galvanic Susceptibility Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). Due to indications found during License Renewal Implementation, future inspections will be monitored by the Service Water Piping Corrosion Program [UFSAR Section 18.3.21].

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.3 Keowee Air and Gas Systems Inspection

Purpose - The purpose of the Keowee Air and Gas Systems Inspection will be to characterize the loss of material due to general corrosion of the carbon steel components within the Carbon Dioxide, Depressing Air, and Governor Air Systems at Keowee that may be exposed to condensation.

Scope - The results of this inspection will be applicable to the carbon steel components within the license renewal portion of the Carbon Dioxide, Depressing Air, and Governor Air Systems on each unit at Keowee.

Aging Effects - The inspection will determine the existence of loss of material due to general corrosion of carbon steel components in the Carbon Dioxide, Depressing Air, and Governor Air Systems. The inspection will assess the likelihood of the impact of this aging effect on the component intended function.

Method - An inspection of selected portions of each system will determine whether loss of material due to general corrosion will be an aging effect of concern for the period of extended operation. The results of the Keowee Air and Gas Systems Inspection will determine the need for additional programmatic oversight to manage this aging effect.

For the Carbon Dioxide System, the discharge piping low elevation point will be determined. A volumetric examination will be conducted on a portion of carbon steel pipe in and around this low point of the Carbon Dioxide System.

For the Depressing Air System, a volumetric examination will be conducted on a portion of piping between the control valves and the Keowee unit turbine head cover.

For the Governor Air System, a visual examination of the bottom half of the interior surface of the air receiver tanks will determine the presence of corrosion. The visual examination will also serve to characterize any instance of corrosion. Piping between the air receiver tank and the governor oil pressure tank will receive a volumetric examination.

Sample Size - For the Carbon Dioxide System, the inspection will include four feet of pipe around the system low elevation point (two feet upstream and downstream).

For the Depressing Air System, the inspection will include one of the two four-foot sections of piping between the control valves and the Keowee unit headcover.

For the Governor Air System, the inspection will include the lower half of each Air Receiver Tank and one of the two four-foot sections of the piping between the air receiver tanks and the governor oil pressure tanks.

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Keowee Air and Gas Systems Inspection is a one-time inspection.

Acceptance Criteria or Standard - Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Problem Investigation Program. The Problem Investigation Program will apply to all structures and components within the scope of the Keowee Air and Gas Systems Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). Due to indications found during License Renewal Implementation, future inspections will be monitored by the Service Water Piping Corrosion Program [UFSAR Section 18.3.21].

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.4 Once Through Steam Generator Upper Lateral Support Inspection

Purpose - The purpose of the OTSG Upper Lateral Support Inspection is to determine whether cracking of the OTSG upper lateral support lubrite pads has occurred and to evaluate the need for future inspections.

Scope - The results of this inspection will be applicable to all thirty lubrite pads installed at Oconee (ten per unit).

Aging Effects - The applicable aging effect is cracking of the lubrite pads by gamma irradiation.

Method - A visual inspection of the accessible surfaces of a sample population of lubrite pads will be performed to determine if the pads are cracking.

Sample Size - The sample size will be five lubrite pads on one OTSG upper lateral support. The OTSG containing these pads will be randomly selected from the total population of six OTSG at Oconee.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The OTSG Upper Lateral Support Inspection is a one-time inspection.

Acceptance Criteria or Standard - No visible cracking in the lubrite pads.

Corrective Action – There are no corrective actions as all 30 pads will be replaced. If there is any cracking of the lubrite pads, an engineering evaluation will determine the need for future inspections and their periodicity. Specific corrective actions and confirmation are implemented in accordance with the Corrective Action Program.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.5 Pressurizer Examinations

18.2.5.1 Pressurizer Cladding, Internal Spray Line, and Spray Head Examination

Purpose - The purpose of the Pressurizer Cladding, Internal Spray Line, and Spray Head Examination will be to assess the condition of the pressurizer cladding, internal spray line, and spray head.

Scope - The results of the Oconee Unit 1 pressurizer inspection will be applicable to the Oconee Unit 2 and Unit 3 pressurizers. The applicable components of the pressurizer will include the following: internal spray line, spray line fasteners, spray head, pressurizer cladding, and attachment welds to the cladding.

Aging Effects - The aging effects of concern are cracking of cladding by thermal fatigue, which may propagate to the underlying ferritic steel. Cracking of the internal spray line by fatigue and cracking and loss of fracture toughness due to thermal embrittlement of the spray head [Reference 3] are also aging effects.

Method - Visual examination (VT-3) of the clad inside surfaces of the pressurizer (100% coverage of the accessible surface) including attachment welds to the pressurizer will be performed. Historical data (Haddam Neck) indicates cracking may occur adjacent to the heater bundles, if at all. Therefore, the examination will focus on cladding adjacent to the heater bundles. In addition, visual inspections have been shown to be adequate for detecting cracks in cladding at Haddam Neck; cracking that extended to underlying ferritic steel was found due to the observance of rust.

Visual examination (VT-3) of the internal spray line and spray head, including the fasteners that are used to attach the spray line to the internal surface of the pressurizer will also be performed.

Sample Size - The examination will be performed on the cladding (100% coverage of the accessible surface), spray head, and internal spray line of one pressurizer at Oconee.

Industry Code or Standards - ASME Section XI.

Frequency - The Pressurizer Cladding, Internal Spray Line, and Spray Head Examination is a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for visual examinations will be in accordance with ASME Section XI VT-3 examinations.

Corrective Action - If cracks are detected in the cladding that extend to the underlying ferritic steel, acceptance standards for Examination Categories B-B and B-D may be applicable to subsequent volumetric examination of ferritic steel.

If cracks are detected in the internal spray piping, acceptance standards for Examination Category B-J may be applied. If cracks are detected in the spray head, engineering analysis will determine corrective actions that could include replacement of the spray head.

The need for subsequent examinations will be determined after the results of the initial examination are available.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The VT-3 examinations for the Oconee Unit 1 pressurizer will occur in two phases. Phase one examinations will consist of VT-3 examinations of the internal spray line, spray line fasteners, spray head, accessible cladding, and attachment welds to the cladding. These examinations will occur down to the pressurizer thermowell or 1 foot above the water level during the 1EOC26 outage occurring in April 2011. The phase two examinations will consist of the cladding and attachment welds below the pressurizer thermowell or below the water level that was identified during the Phase 1 examinations. Emphasis will be placed on the cladding adjacent to the pressurizer heater bundles. These examinations will occur during the same outage of the pressurizer heater bundle replacement project. Only the phase one examinations will be completed by February 6, 2013 which is the end of the initial license for Oconee Unit 1.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.5.2 Pressurizer Heater Bundle Penetration Welds Examination

Purpose - The purpose of the Pressurizer Heater Bundle Penetration Welds Examination will be to assess the condition of the Unit 1 pressurizer heater penetration welds.

Scope - The results of this examination will be applicable to the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds for the pressurizer heater bundles of Oconee Unit 1 (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not required. [Reference 4]

Aging Effects - The aging effect of concern is cracking at heater bundle penetration welds which may lead to coolant leakage.

Method - For the heater bundle that is removed, a surface examination of sixteen peripheral welds on one bundle will be performed. A visual examination (VT-3 or equivalent) of the remaining welds of the heater bundle will be performed.

Sample Size - The examination will include sixteen peripheral heater penetration welds on one heater bundle from Oconee Unit 1, whichever heater bundle is removed first. The examination will include the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds of the sixteen peripheral heaters.

Industry Code or Standards - ASME Section XI.

Frequency - The Pressurizer Heater Bundle Penetration Welds Examination is a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for surface examinations and visual examination (VT-3) will be in accordance with ASME Section XI.

Corrective Action - If the results of the inspection are not acceptable, then the results may be used as a baseline inspection for establishing a longer term programmatic action covering all Oconee pressurizer heater bundles.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The surface examinations of the sixteen peripheral heater penetration welds will be performed upon removal of a pressurizer heater bundle. This examination will be aligned to when a Unit 1 heater bundle is replaced whenever that may occur, due to the impractical nature of such an inspection otherwise. The failure of a structural weld that attaches the heater sheath to the Alloy 600 heater sleeve or failure of the weld that attaches the heater sleeve to the Alloy 600 diaphragm plate would result in leakage within the make-up system capacity and the integrity of the heater bundle bolted closure would not be compromised. No loss of pressurizer function would occur due to leakage at either of these welds. The examination will provide insights into the condition of the other similarly constructed pressurizer heater bundles in Oconee Unit 1. [Reference 5]

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

Due to pressurizer heater bundle (PHB) seal weld leakage identified in 2003, TMI-1 replaced the affected PHB and an inspection of the removed heater bundle was performed by Exelon. There was no observed degradation due to primary water stress corrosion cracking (PWSCC) and the results of this examination are documented in a B&W Owners Group Report completed in the spring of 2005. Only TMI-1 and ONS-1 have PHBs with Alloy 600 components that are susceptible to PWSCC. This TMI-1 component examination meets all the ONS UFSAR requirements for the ONS one-time LR examination for this component, and thus is credited for the ONS-1 license renewal examination for this identical component. Therefore, the ONS-1 LR commitment has been satisfied by the TMI-1 examinations and therefore, this one-time LR examination requirement is completed.

18.2.6 Reactor Building Spray System Inspection

Purpose - The purpose of Reactor Building Spray System Inspection will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components within the Reactor Building Spray System periodically exposed to a borated water environment that is not monitored.

Scope - The results of this inspection will be applicable to stainless steel piping and components downstream of the containment isolation valves BS-1 and BS-2 toward their respective spray headers, a total of two lines per Oconee unit. Because the piping is open to the Reactor Building environment, unmonitored conditions exist in any borated water, which may be entrapped downstream of these valves. Results of this inspection will be applied to not only the Reactor Building Spray System, but also to the Nitrogen Purge and Blanketing System.

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping due to the periodic presence of borated water in the Reactor Building Spray piping open to the Reactor Building environment. The inspection will assess the likelihood of the impact of these aging effects on the component intended function.

Method - An inspection of a select set of stainless steel piping locations will determine whether loss of material due to pitting corrosion and cracking due to stress corrosion have been occurring and whether further programmatic aging management will be required to manage these effects for license renewal. The length of susceptible piping will be determined. A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone, since this is a more likely location for stress corrosion cracking to occur.

Sample Size - The inspection will include one of the six susceptible locations. The inspection locations are the piping between valves BS-1 and BS-2 and the normally open drain valves BS-15 and BS-20. Some of the parameters Duke may use to select the most bounding inspection location are piping geometry, presence of weld and heat affected zone, accessibility of location and radiation exposure. [Reference 6]

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Reactor Building Spray System Inspection is a one-time inspection.

Acceptance Criteria or Standard - No cracking will be permitted. Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.7 Reactor Coolant Pump Motor Oil Collection System Inspection

Purpose - The purpose of the Reactor Coolant Pump Motor Oil Collection System Inspection will be to characterize the loss of material due to general and localized corrosion of the carbon steel, copper alloy and stainless steel components in the Reactor Coolant Pump Motor Oil Collection System that may periodically be exposed to water.

Scope - The results of this inspection will be applicable to the components in the system, particularly the lower portions of the system, with the potential to be exposed to water. Each Oconee unit has four Reactor Coolant Pump Oil Collection Tanks for a total population of twelve at Oconee.

Aging Effects - The inspection will determine the existence of loss of material due to general and galvanic corrosion for the carbon steel component materials and pitting and crevice corrosion for the carbon steel, copper alloys and stainless steel component materials as a result of periodic exposure to water.

Method - An inspection of the Reactor Coolant Pump Motor Oil Collection System Tanks will determine whether loss of material due to general and localized corrosion will be an aging effect of concern for the period of extended operation. The evidence gained from the tank examination will be indicative of the condition of all materials in the lower portion of the system.

A visual examination on the bottom half of the interior surface of the tank will be performed to determine the presence of corrosion. The visual examination will also serve to characterize any instances of corrosion, both general and localized. A volumetric examination will then be conducted on any problematic areas to determine the condition of the lower portions of the tank that is a leading indicator of the other susceptible components.

Sample Size - The inspection will include one of the twelve Reactor Coolant Pump Motor Oil Collection System Tanks. The collection tank chosen for inspection will be based on any higher frequency that water has been observed in the oil as well as accessibility and radiological concerns. [Reference 7]

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Reactor Coolant Pump Motor Oil Collection System Inspection is a one-time inspection.

Acceptance Criteria - Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to various forms of corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Problem Investigation Program. The Problem Investigation Program will apply to all structures and components within the scope of the Reactor Coolant Pump Motor Oil Collection System Inspection.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.8 Small Bore Piping Inspection

Purpose - The purpose of the Small Bore Piping Inspection will be to validate that service-induced weld cracking is not occurring in the small bore Reactor Coolant System piping that does not receive a volumetric examination under ASME Section XI.

Scope - The scope of Small Bore Piping Inspection includes the Oconee inservice inspection Class A piping welds in lines less than 4 inch nominal pipe size including pipe, fittings, and branch connections.

Aging Effects - The aging effect being investigated is cracking of piping welds which may not be fully managed by the current ASME Section XI examinations. For Duke, these inspections are driven by the consequences of small bore piping failures rather than a lack of confidence in the current inservice inspection techniques to manage aging. In many instances, small bore piping cannot be isolated from the Reactor Coolant System and a leak could lead to a small break loss of coolant accident and plant shutdown.

Method - Selected inspection locations will receive either a destructive or non-destructive examination that permits inspection of the inside surface of the piping.

Sample Size - Pipe, fittings, and branch connections over the entire small bore size range will be considered for inspection. The total population of welds will be determined by summing the number of welds found in scope. To determine the inspection locations from this total

population of welds, risk-informed approaches will be used to identify locations most susceptible to cracking. Susceptibility will be determined either qualitatively (i.e., based on site and industry experience, evaluation of current ASME Section XI inspection requirements and results, and any applicable regulatory initiatives) or quantitatively, or both. The consequences of weld failure, without respect to susceptibility, also will be evaluated to identify the most safety significant piping welds. After the evaluation of susceptibility and consequences, a list of potential inspection locations will be developed. Actual inspection locations will be selected based on physical accessibility, exposure levels, and the likelihood of meaningful results if a non- destructive technique is employed.

Industry Code or Standards - No code or standard exists to guide or govern this inspection. ASME Section XI provides rules for this piping, but not for volumetric or destructive examination. If destructive examination is employed, the Section XI rules for Repair and Replacement will be used to return piping to its original condition.

Frequency - The Small Bore Piping Inspection is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of cracking of piping welds as determined by engineering analysis. The ONS One-Time Small Bore Piping Examinations did not identify any new degradation mechanisms. However, Operational Experience (OE) reviews performed as part of the development of the Small Bore Piping Examination Program did document specific degradation mechanisms that were identified outside the Small Bore Piping Examination scope. This OE degradation was fully addressed under the Oconee Corrective Action Program.

Corrective Action - Any unacceptable indication of cracking of piping welds requires an engineering analysis be performed to determine proper corrective action.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1). No unacceptable degradation was indentified under the One-Time, Small Bore Piping Examinations. However, the Oconee Thermal Fatigue Manangement Program (TFMP), also a License Renewal Commitment, was used to address the significant OE degradation identified outside of the Small Bore Piping Examinations. Since the TFMP is an active program for ONS within the Period of Extended Operation, no additional Programs or Activities are required to address the OE items documented under the Small Bore Piping Examinations.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.9 Treated Water Systems Stainless Steel Inspection

Purpose - The purpose of the Treated Water Systems Stainless Steel Inspection will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components that could be occurring within several Oconee treated water systems.

Scope - The results of this inspection will be applicable to the stainless steel piping and valves in portions of several Oconee treated water systems which are exposed to treated or potable water falling under separate guidelines from the Chemistry Control Program and the state of South Carolina. The stainless steel components may experience aging that is not monitored by current plant programs. The focus on this inspection will be on a representative sample from

each of the two treated water groups. The results of the inspections in each group will be an indicator of the condition of all of the stainless steel components in the systems within that group. The systems containing the stainless steel piping and valves under consideration are:

1. Chemical Addition System (caustic addition portion containing demineralized water)
2. Component Cooling System (the stainless steel Containment penetration portion on Unit 2 only containing demineralized water)
3. Chilled Water System (containing potable water)
4. Demineralized Water System (Containment penetration portion containing demineralized water)
5. Diesel Jacket Cooling Water System (containing demineralized water)
6. Liquid Waste Disposal System (Containment penetration portion containing demineralized water)
7. SSF Drinking Water System (containing potable water)
8. SSF Sanitary Lift System (containing potable water)

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping and valves.

Method - A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone since this is a more likely location for stress corrosion cracking to occur. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion.

Sample Size - Portions of stainless steel piping and valves, as applicable, for each of the two groups of system components will be inspected. If in the Demineralized Water System no parameters exist that would distinguish among the four Containment penetrations, one of the three, 4-inches nominal pipe size, Containment penetrations will be inspected. A stainless steel weld at one Containment isolation valve along with piping and weld between the isolation valve and the containment penetration schedule transition point will be volumetrically examined. In addition, one valve will be disassembled for an internal visual examination.

In the SSF Drinking Water System, a one-foot section of 1-inch nominal pipe size piping will be volumetrically examined upstream of valve PDW-72. In addition, one valve will be disassembled in the license renewal portion of this system for an internal visual inspection.

Industry Code and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Frequency - The Treated Water Systems Stainless Steel Inspection is a one-time inspection.

Acceptance Criteria or Standards - No unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss of material due to of pitting corrosion or stress corrosion cracking requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Problem Investigation Program. The Problem Investigation Program will apply to all structures and components within the scope of the Treated Water Systems Stainless Steel Inspection.

Timing of New Program or Activity - Following issuance of renewed operating license for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.2.10 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
3. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
4. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
5. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.3-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
6. M. S. Tuckman (Duke) letter dated May 10, 1999 to Document Control Desk (NRC), Attachment 1, Response to Items 4.3.9-6, - 7, and -8, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
7. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

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18.3 Aging Management Programs and Activities

18.3.1 Alloy 600 Aging Management Program

The original Alloy 600 Aging`Management Review was proposed during the license renewal review process for Oconee Nuclear Station, and incorporated into the current licensing basis with the issuance of a renewed operating license on May 23, 2000. The original program description is being revised to reflect requirements imposed and commitments made subsequent to issuance of the renewed operating license. Unless otherwise noted, the intent of the original Alloy 600 Aging Management Review is met by the more comprehensive Alloy 600 Aging Management Program.

The purpose of the Alloy 600 Aging Management Program is to ensure that Alloy 600/82/182 high strength nickel alloy materials used in pressure boundary applications are adequately examined, mitigated, or replaced on a selective basis prioritized utilizing operating experience, examination requirements, and a temperature based susceptibility ranking. The program will facilitate the oversight and management of degradation due to Primary Water Stress Corrosion Cracking (PWCSS).

Consideration of industry operating experience is part of the Alloy 600 Aging Management Program. The NRC staff issued multiple generic communications regarding degradation of Alloy 600/82/182 materials. These communications imposed requirements on specific components in the Reactor Coolant System. A one-time examination of the bottom head of the reactor vessel (Reference 40) and on-going examinations of the reactor vessel closure head (Reference 41) and the pressurizer (Reference 42, 43, and 44) were initially required. Subsequent to these initial examination requirements, the NRC staffed approved ASME Code Cases N-722-1 (Reference 47), N-729-1 (Reference 46), and N-770-1 (Reference 55) with conditions specified in 10 CFR 50.55a. ASME Code Case N-722-1 specifies visual examination requirements for components fabricated with Alloy 600/82/182 materials. ASME Code Case N-729-1 specifies examination requirements for reactor vessel closure heads. ASME Code Case N-770-1 specifies examination requirements for mitigated and unmitigated butt welds fabricated from Alloy 600/82/182 materials, which superceded the examination requirements of MRP-139 (Reference 49). In addition to ASME Code and regulatory requirements, guidelines developed by the EPRI Materials Reliability Program and endorsed as "needed" or "mandatory" according to NEI-03-08, "Guidelines for the Management of Materials Issues," will be implemented.

Deleted Paragraphs Per 2016 Update.

The reactor vessel closure head penetration and pressurizer examination activities are described in Sections 18.3.1.2 and 18.3.1.3, respectively. The susceptibility ranking used in the original Alloy 600 Aging Management Review has been updated as described in Section 18.3.1.1

Specific corrective actions are implemented in accordance with the Duke Energy Quality Assurance Program.

18.3.1.1 Susceptibility Ranking

The original Alloy 600 Aging Management Review identified all Alloy 600/82/182 locations and performed a qualitative temperature based susceptibility ranking of these components for use in determining an adequate aging management inspection program. The initial inspections were to be completed before 2/6/2013, the end of the initial license term for Oconee Unit 1. As of the end of 2014, all Alloy 600 materials in the reactor vessel clousre heads, the steam generators,

the pressurizers, and the hot leg decay heat nozzels for all three Oconee units have been either mitigated by full structural weld overlay or replaced with Alloy 690/52/152 or stainless steel materials. The current Alloy 600 Program also continues to identify the locations of Alloy 690/52/152 components.

The Alloy 600 Program change from a susceptibility based inspection regime to an active mitigation and examination strategy is based on industry Operational Experience (OE). Starting in 2000, it became apparent that an inspection schedule based on a susceptibility ranking of Alloy 600/82/182 components could not account for the PWSCC identified by OE within the nuclear industry. Therefore, Oconee updated the Alloy 600 Program to preemptively replace or mitigate the Alloy 600/82/182 components with PWSCC resistant materials (Alloys 690/52/152 or stainless steel). The mitigation priority was based on the component operating temperature combined with the component's ability to be volumetrically examined for PWCSS. When the EPRI Materials Reliability Program published MRP 139 (Reference 49), those volumetric examination requirements were integrated into the Alloy 600 Program. The inspection requirements of MRP 139 were subsequently replaced with ASME Code Case N-770-1 as conditioned by 10 CFR 50.55a. In addition, ASME Code Case N-722-1 as conditioned by 10 CFR 50.55a was added for visual examination of Alloy 600/82/182 components, and ASME Code Case N-729-1 as conditioned by 10 CFR 50.55a was added for PWR reactor vessel closure heads having pressure retaining partial penetration welds. Therefore, Oconee chose to prioritize mitigation of the Alloy 600/82/182 components based on a combination of temperature and the ability to implement examination requirements in lieu of using the primarily temperature based Alloy 600/82/182 PWSCC susceptibility models developed in the late 1990s.

Specific corrective actions are implemented in accordance with the Duke Energy Quality Assurance Program.

18.3.1.2 Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection

Scope - The scope of the Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection includes nozzles having pressure-retaining partial-penetration welds and carbon steel closure head surfaces of each reactor pressure vessel (RPV) as described in ASME Boiler and Pressure Vessel Code, Section XI, Code Case N-729-1 (Reference 46) subject to the conditions in paragraphs (g)(6)(ii)(D)(2) through (6) of 10CFR 50.55a.

Preventive Actions - No actions are taken as part of the Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection to prevent aging effects or to mitigate aging degradation. However, the original Oconee RPV closure heads were replaced after the renewed licenses were issued.

Parameters Monitored or Inspected – The Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection monitors cracking of RPV closure head nickel based alloy nozzles and pressure-retaining partial-penetration welds, as well as associated borated water leakage onto the closure head carbon steel surface.

Detection of Aging Effects – In accordance with information provided in Monitoring and Trending below, the Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection will detect cracking of nickel based alloy RPV closure head penetrations prior to loss of component intended function.

Monitoring and Trending – The Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection will inspect all RPV closure head nozzles having pressure-retaining

partial-penetration welds and the RPV closure head outer surface. The RPV closure head inspections will consist of visual, volumetric, and/or surface examinations.

The replacement Oconee RPV closure heads are composed of PWSCC-resistant materials. The following is a brief summary of the inspections required by ASME Section XI Code Case N-729-1 subject to the conditions specified in 10CFR 50.55a for RPV closure heads with nozzles having pressure-retaining partial-penetration welds of PWSCC-resistant materials.

- A visual examination of the bare-metal surface of the entire outer surface of the head, including essentially 100% of the intersection of each nozzle with the head every third refueling outage or 5 calendar years, whichever is less.
- A volumetric and/or surface examination of all partial-penetration weld nozzles, not to exceed one inspection interval (nominally 10 calendar years). These examinations should cover essentially 100% of the required volume or equivalent surfaces of the nozzle tube, as identified by Figure 2 of ASME Code Case N-729-1. A demonstrated volumetric or surface leak path assessment through all J-groove welds shall be performed.

Deleted Paragraph per 2012 update.

Acceptance Criteria – The visual, volumetric, and surface examinations will use the acceptance criteria set forth in ASME Code Case N-729-1 subject to the conditions specified in 10CFR 50.55a.

Corrective Action and Confirmation Process – For the visual examination, if relevant conditions are detected, the source of leakage and leakpath will be determined and repairs completed. Specific corrective actions and confirmation are implemented in accordance with the Corrective Action Program, the Boric Acid Corrosion Control Program, and ASME Code Case N-729-1 subject to the conditions specified in 10CFR 50.55a.

For the volumetric and/or surface examination, if relevant indications are detected which cannot be justified for continued service by analysis, the component will be repaired in accordance with ASME Section XI. Flaws which can be justified for continued service will be managed by the station Corrective Action Program and in accordance with ASME Code Case N-729-1 subject to the conditions specified in 10CFR 50.55a.

Administrative Controls – Inspections will be controlled by site specific procedures. Engineering evaluations are performed in accordance with the station Corrective Action Program, the Boric Acid Corrosion Control Program, and ASME Code Case N-729-1 subject to the conditions specified in 10CFR 50.55a.

Prior to the September 10, 2008 CFR Part 50 Rule Change, RPV closure head examinations were dictated by First Revised NRC Order EA-03-009 (Reference 41). Per 10CFR 50.55a (g)(6)(ii)(D)(1) all licensees of PWR's shall augment their inservice inspection program with ASME Code Case N-729-1 subject to the conditions specified in paragraphs (g)(6)(ii)(D)(2) through (6). This augmented inservice inspection program should be implemented by December 31, 2008. Once a licensee implements this requirement, the First Revised NRC Order EA-03-009 no longer applies and is deemed to be withdrawn.

18.3.1.3 Pressurizer Inspection

Scope – The scope of the Pressurizer Inspection includes pressurizer connections containing Alloy 600/82/182 materials. These inspections ensure that commitments made in response to NRC Bulletin 2004-01 contained in References 42, 43, and 44, remain satisfied by ASME Code Cases N-722-1 (Reference 47) and N-770-1 (Reference 55) and the associated conditions imposed by 10CFR 50.55a.

Preventive Actions – Due to industry OE and the development of MRP-139 and Code Case N-722-1, and Code Case N-770-1, inspection and mitigation actions were implemented in accordance with these documents. As of the end of 2014, there are no unmitigated pressure boundary Alloy 600/82/182 materials remaining on the Oconee Units 1, 2, or 3 pressurizers.

Deleted Per 2014 Update

18.3.2 Chemistry Control Program

The primary objective of the Oconee Chemistry Control Program is to protect the integrity, reliability, and availability of plant equipment and components by minimizing corrosion in fluid systems. To ensure the best protection is provided, reactor coolant water quality specifications are based upon the current revision of the EPRI PWR Primary Water Chemistry Guidelines and vendor recommendations as appropriate [UFSAR Section 5.2.1.7]. Secondary chemistry specifications are based upon the recommendations in the current revision of the EPRI PWR Secondary Water Chemistry Guidelines.

For the Component Cooling System, the Chilled Water System (WC), and the SSF Diesel Generator Jacket Cooling Water System, Oconee utilizes chemistry control specifications that are consistent with the EPRI Closed Cooling Water Chemistry Guideline. For the SSF diesel jacket water cooling system, Oconee utilizes an industry-standard approved corrosion inhibitor to control corrosion in the SSF diesel jacket water cooling system.

The Oconee SSF Fuel Oil surveillances are governed by Oconee Technical Specifications [ITS SR 3.10.1.8 and ITS 5.5.14]. The applicable ASTM standard is ASTM D975 Standard, "Standard Specification for Diesel Fuel Oils."

Acceptance criteria for each monitored parameter have been established and are described in the applicable section of the Oconee Chemistry Manual. In the event the acceptance criteria are not met, then specific corrective actions will be implemented in accordance with the Problem Investigation Process.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.3 Containment Inservice Inspection Plan

The Containment Inservice Inspection Plan was developed to implement applicable requirements of 10 CFR 50.55a. Section 50.55a(g)(4) requires that throughout the service life of nuclear power plants, components which are classified as either Class MC or Class CC pressure retaining components and their integral attachments must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in §50.55a(b).

Furthermore, §50.55a(g)(4)(v)(B) and (C) require that metallic shell and penetration liners which are pressure retaining components and their integral attachments in concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class MC; and that concrete containment pressure retaining components and their integral attachments, and the post-tensioning systems of concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class CC.

These requirements are subject to the limitation listed in paragraph (b)(2)(vi) and the modifications listed in paragraphs (b)(2)(viii) and (b)(2)(ix) of §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the components.

Specific corrective actions are implemented in accordance with the Duke Energy Quality Assurance Program.

18.3.4 Deleted Per 2004 Update

This section has been relocated to Section 18.3.1.2.

18.3.5 Crane Inspection Program

Purpose - The purpose of the Crane Inspection Program is to provide periodic inspections and preventive maintenance on Oconee cranes and hoists. A subset of the many inspection activities performed under the auspices of the Crane Inspection Program is the inspection of the structural components.

Scope - Structural components associated with the following cranes and hoists are included in the Crane Inspection Program for license renewal:

Building	Crane
Auxiliary Building	Spent Fuel Bay Crane
	Spent Fuel Pool Fuel Handling Crane
	Hoists located over safety-related equipment
Keowee	270 Ton Crane
	Intake Hoist
	Hoists located over safety-related equipment
Reactor Building	Polar Crane
	2 Ton CRDM Service Crane
	Main Fuel Handling Bridge
	Equipment Hatch Hoist
	Hoists located over safety-related equipment
Turbine Building	Pump Aisle Crane
	Turbine Aisle Crane
	Turbine Aisle Auxiliary Crane
	Heater Bay Crane
	Hoists located over safety-related equipment
Standby Shutdown Facility	Hoists located over safety-related equipment

A complete list of cranes and hoists located over safety-related equipment is maintained at Oconee.

Aging Effects - The applicable aging effect is loss of material due to corrosion of the steel components.

Method - The program requires visual inspections of cranes and hoists within the scope.

Industry Code or Standard - ANSI B30.2.0 [Reference 6] for cranes and ANSI B30.16 [Reference 7] for hoists.

Frequency - Each crane and hoist is subject to several inspections. The inspection frequencies for the cranes are based on the guidance provided by ANSI B30.2.0. The inspection frequencies for hoists are based on guidance provided by ANSI B30.16. However, each crane or hoist over safety-related equipment and outside of the Reactor Building shall be inspected at least once a year independent of the status of the crane or hoist.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material as determined by the accountable engineer.

Corrective Action - Items which do not meet the acceptance criteria are repaired or replaced. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - 29 CFR Chapter XVII, Section 1910.179 [Reference 8], Application [Reference 1] and Final SER [Reference 2].

18.3.6 Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances

Purpose - The purpose of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances is to inspect the structural integrity of the Keowee intake structure, spillway, and powerhouse.

Scope - The scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances includes:

1. Keowee Intake - trashracks, support steel and concrete
2. Spillway - concrete
3. Powerhouse - concrete

Aging Effects - The applicable aging effects include loss of material due to corrosion for steel components and loss of material, cracking, and change in material properties of concrete components.

Method - The program requires visual examinations of external surfaces. The examination of external surfaces covers the Keowee Intake, Spillway, and Powerhouse concrete surfaces exposed to water. The concrete structures are inspected from the foundation to the free water surface. [Reference 9]

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed once every five years. The inspection frequency is consistent with the periodicity of inspections performed by Duke Energy in accordance with FERC requirements for maintaining other components of the structures. (See Section 18.3.8).

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material, cracking, or change in material properties as determined by the accountable engineer.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated by the accountable engineer. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Project and Project Works, Application [Reference 1] and Final SER [Reference 2].

18.3.7 Elevated Water Storage Tank Civil Inspection

Purpose - The purpose of the Elevated Water Storage Tank Civil Inspection is to provide a visual examination of the interior surfaces of the tank and associated components to ensure their structural integrity.

Scope - The scope of the program includes the interior surfaces of the Elevated Water Storage Tank and associated components.

Aging Effects - The applicable aging effect is loss of material due to corrosion.

Method - The program requires visual examinations of internal surfaces in accordance with station procedures. The inspection covers 100% of the interior tank surfaces. [Reference 9]

Industry Code or Standard - NFPA 25, Standard for the Inspection, Testing, and Maintenance of Water- Based Fire Protection Systems.

Frequency - Inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material due to corrosion as determined by the accountable engineer.

Corrective Action - Items that do not meet the acceptance criteria are evaluated for continued service, monitored, or corrected. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.8 Federal Energy Regulatory Commission (FERC) Five Year Inspections

Inspections of the Keowee River Dam; Little River Dam; Little River Dikes A, B, C, and D; Oconee Intake Canal Dike; Keowee Spillway and Left Abutment, Keowee Intake and Powerhouse are performed in accordance with the requirements contained in 18 CFR Part 12, Safety of Water Power Projects and Project Works [Reference 10]. Specific corrective actions and confirmation are implemented in accordance with the Corrective Action Program.

18.3.9 Flow Accelerated Corrosion Program

Purpose - The purpose of the Flow Accelerated Corrosion Program is to manage loss of material for the component locations in the Feedwater System and Main Steam System that have been identified as being susceptible to flow accelerated corrosion.

Scope - The portion of the overall program credited for license renewal includes the components in the Feedwater System between the main control valves, bypass block valves, and the steam generator, and a small section of Main Steam System piping downstream of the Emergency Feedwater pump turbine steam supply control valve.

Aging Effects - The aging effect of concern is loss of material of carbon steel components due to flow accelerated corrosion under certain relevant conditions. Relevant conditions include physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, mechanical component geometry and piping configuration. An analytical review process is used to determine susceptible locations based on these types of relevant conditions.

Method - The focus of the program is on the carbon steel components in the more susceptible locations within these systems. Over seventy total inspection locations exist for the three units' Feedwater Systems and ten separate inspection locations exist for the three units' Main Steam Systems. Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing and radiography. Also visual examination is used when access to interior surfaces is allowed by component design.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. However, the program follows the basic guidelines or recommendations provided by EPRI Document NSAC- 202L. Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Frequency - Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experiences.

Acceptance Criteria - Using inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record.

Corrective Action - If the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis. Specific corrective actions are implemented in accordance with approved station processes, including work orders, modifications and the Problem Investigation Program.

Regulatory Basis - Duke response to Bulletin 87-01 [References 11 and 12] and Duke response to Generic Letter 89-08 [References 13 and 14], Application [Reference 1] and Final SER [Reference 2].

18.3.10 Boric Acid Corrosion Control Program

Purpose - The purpose of the Boric Acid Corrosion Control Program is to ensure identification of leaks followed by timely investigation and repair. When boric acid leakage is involved, this program describes activities to identify the source of leakage and to evaluate subsequent corrosion degradation of associated piping, structures and components. This program includes focus on small leaks that generally occur below technical specification limits for operational leakage.

Scope - The results of the program are applicable to mechanical components and structural components fabricated from aluminum, brass, bronze, copper, galvanized steel, carbon steel and low alloy steel that are located in proximity to borated systems. Electrical equipment located in proximity to borated systems is also included. This program addresses equipment both inside and outside the Reactor Building. Bolted closures such as manways and flanged connections of systems containing dissolved boric acid are also included.

Aging Effects - Two of the conditions evaluated by the Boric Acid Corrosion Control Program are loss of material from components due to boric acid corrosion of the carbon steel and low alloy steel and boric acid intrusion into electrical equipment.

Method - Visual inspections are performed on external surfaces in accordance with plant procedures. Plant personnel look for leakage from both insulated and uninsulated components, as well as general corrosion of a component that may result from leakage. Plant personnel look for borated water leakage indicators such as discoloration or accumulated residue on surfaces such as insulation materials or floors. Possible intrusion of boric acid into electrical equipment is evaluated.

Industry Code or Standard - ASME Section XI and Generic Letter 88-05 [Reference 15].

Frequency - Reactor Building inspections are performed each refueling outage or every 24 months. Inspections of the Auxiliary Building are performed at a minimum as frequently as the Reactor Building is inspected. [Reference 16]

Acceptance Criteria or Standard - The Boric Acid Corrosion Control Program defines actions to achieve the following acceptance criteria:

1. Insulated, non-insulated or inaccessible components within borated water systems will not have external leakage, and
2. Components within scope with degradation resulting from external leakage from borated water systems will be evaluated by engineering.

Corrective Action - When the programmatic activities described in the Boric Acid Corrosion Control Program lead to detection of an unacceptable condition, the following corrective actions are required:

1. Locate leak source and areas of general corrosion.
2. Evaluate pressure-retaining components suffering wall loss for continued service or replacement.
3. Evaluate other affected components such as supports and other structural members for continued service, repair or replacement.

Specific corrective actions are implemented in accordance with the Boric Acid Corrosion Control Program or the Problem Investigation Program. These programs apply to all structures and components within the scope of the Boric Acid Corrosion Control Program.

Regulatory Basis - ASME Section XI, Examination Category B-P, All Pressure Retaining Components, Examination Category C-H, All Pressure Retaining Components; Examination Category D-A, Systems in Support of Reactor Shutdown Function; Examination Category D-B, Systems in Support of Emergency Core Cooling, Containment Heat Removal, Atmospheric Cleanup, and Reactor Residual Heat Removal and Examination Category D-C, Systems in Support of Residual Heat Removal from Spent Fuel Storage Pool; Duke commitments in response to NRC Generic Letter 88-05 [Reference 17], Application [Reference 1], Final SER [Reference 2], and Duke letter [Reference 18].

18.3.11 Heat Exchanger Performance Testing Activities

The following heat exchangers in the scope of license renewal have heat transfer as a component intended function that could be impacted by fouling. Each of these heat exchangers has raw water from the Low Pressure Service Water System or the Standby Shutdown Facility Auxiliary Service Water System:

1. the decay heat removal coolers in the Low Pressure Injection System,
2. the Reactor Building cooling units in the Reactor Building Cooling System, and
3. the component coolers in the Component Cooling System
4. the Standby Shutdown Facility HVAC coolers in the Standby Shutdown Facility Auxiliary Service Water System.

Periodic testing is completed each refueling outage or every 24 months for the decay heat removal coolers and for the Reactor Building cooling units. Performance testing for these heat exchangers will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands. Heat removal capacity is determined and compared to test acceptance criteria established by the accountable engineer and to previous test results for the decay heat removal coolers and the Reactor Building cooling units. If an adverse trend in heat removal is found, then corrective actions will be taken.

The Standby Shutdown Facility HVAC coolers are normally in service because they are required for SSF system operability per TS 3.10.1.D. The component coolers are normally in service because they are required to support normal plant operation. Accident load demands for these

coolers are not greater than normal operation. Thus, heat removal capacity calculations are not performed for these coolers. Rather, flowrates through these coolers are monitored on a periodic basis. The Standby Shutdown Facility HVAC cooler flowrate is monitored twice per day. The component cooler flowrate is recorded on a refueling basis during performance testing. If an adverse trend in flowrate is found, then corrective actions will be taken.

If the heat exchangers fail to perform adequately, then corrective actions such as cleaning are undertaken. Specific corrective actions are implemented in accordance with the Problem Investigation Process. This program applies to all structures and components within the scope of the Heat Exchanger Performance Testing Activities.

The continued implementation of the Heat Exchanger Performance Testing Activities provides reasonable assurance that the heat exchangers will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2]. Also, the activities credited here for license renewal for the SSF HVAC coolers, Decay Heat Removal coolers and the Reactor Building cooling Units are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 19, 20, 21, 22, and 23].

18.3.12 Inservice Inspection Plan

The Oconee Inservice Inspection Plan, implements the requirements of 10 CFR 50.55a for Class 1, 2, and 3 components and Class 1, 2, 3, and MC component supports. The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. The period of extended operation for Oconee will contain the 5th and 6th ten-year inservice inspection intervals. The Oconee Inservice Inspection Plan for each of these two inservice inspection intervals will:

1. Include compliance with Appendix VII, Qualification of Nondestructive Examination Personnel for Ultrasonic Examination;
2. Include compliance with Appendix VIII, Performance Demonstration for Ultrasonic Examination Systems;
3. Implement the Subsection IWB examination requirements of either (a) the 1989 Edition of ASME Section XI, or (b) the edition of the ASME Section XI Code required by Section 50.55a(b), or (c) another edition of ASME Section XI provided an appropriate evaluation is performed;
4. Comply with Section 50.55a except that if an examination required by the Code or Addenda is determined to be impractical, then a relief request will be submitted to the Commission in accordance with the requirements contained in Section 50.55a, for Commission evaluation; and
5. Include examination of pressurizer heater bundle welds in accordance with Examination Category B-E (or equivalent).

The Inservice Inspection Plan is credited for license renewal with managing certain aging effects associated with Reactor Coolant System pressure retaining components, their integral attachments, and other structural components within the jurisdiction of ASME Section XI. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

In addition, for Cast Austenitic Stainless Steel (CASS) Class 1 components when conditions are detected during these inservice inspections that exceed the allowable limits of ASME Section

XI, engineering evaluations of either detected or postulated flaws shall be carried out using material properties and acceptance criteria applicable to the evaluation procedures presented in IWB-3640. More favorable material properties and acceptance criteria may be used, if justified, on a case-by-case basis [Reference 1, Volume III, Exhibit A, Chapter 4, and Reference 2].

18.3.13 Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is intended to meet the requirements of 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants (the Maintenance Rule). This program:

1. monitors and assesses mechanical components, civil structures and components and their condition in order to provide reasonable assurance that they are capable of performing their intended functions in accordance with the current licensing basis;
2. monitors degradation of caulking, sealants and waterstops in the Auxiliary Building and Standby Shutdown Facility, as well as the Fiber-reinforced polymer system on the Auxiliary Building, which may include but is not limited to water in-leakage, leaching, peeling paint, or discoloration of the concrete, debonding, blistering, cracking, crazing, deflections; and
3. includes nuclear safety-related structures which enclose, support, or protect nuclear safety-related systems and components and non-safety related structures whose failure may prevent a nuclear safety-related system or component from fulfilling its intended function.

NEI 96-03, Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants, has been used as guidance in the preparation of the Inspection Program for Civil Engineering Structures and Components.

Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Inspection Program for Civil Engineering Structures and Components.

18.3.14 Insulated Cables and Connections Aging Management Program

Purpose - The purpose of the Insulated Cables and Connections Aging Management Program is to provide reasonable assurance that the license renewal intended functions of insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation.

Scope - The Insulated Cables and Connections Aging Management Program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the Reactor Buildings, Auxiliary Buildings, Turbine Buildings, Standby Shutdown Facility, Keowee, in conduit and direct-buried, which could be subject to applicable aging effects from heat, radiation or moisture. This program does not include insulated cables and connections that are in the Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

Aging Effects - Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat, radiation or moisture - conditions that establish an adverse, localized environment, which include energized medium-voltage cables exposed to significant moisture.

Method - The methods used are different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables, which cannot be visually inspected.

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect. In addition, water collection in manholes containing in-scope, medium-voltage cables will be monitored to prevent the cables from being exposed to significant moisture.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested. The specific type of test performed will be determined prior to each test. Significant moisture exposure is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. These definitions apply to cables for which no specific design characteristics are known. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions.

Sample Size - Samples may be used for this program. If used, an appropriate sample size will be determined prior to the inspection or test.

Industry Codes and Standards - EPRI TR-109619, Guideline for the Management of Adverse Localized Equipment Environments will be used as guidance in implementing this program.

Frequency - Accessible insulated cables and connections including Protected Service Water (PSW) 13.8kV cables installed in adverse, localized environments will be inspected at least once every 10 years. Water collection in manholes containing in-scope, medium-voltage cables will be monitored at a frequency adequate to prevent the cables from being exposed to significant moisture. The PSW drainage system of the trenches and manholes containing the PSW 13.8 kV cables shall be inspected annually to detect exposure of these cables to significant moisture and shall include video imaging of the drainage systems of the trench and manholes. If significant moisture is detected, actions shall be taken to correct this condition.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested at least once every 10 years. The PSW System inaccessible 13.8 kV insulated power cables from the Keowee Hydroelectric station to the PSW Building and from the PSW substation to the PSW Building (Fant Line) shall be periodically electrically tested. The initial PSW 13.8 kV cable testing shall be performed prior to declaring the entire PSW System operable and thereafter at a 6 year frequency. The electrical tests shall follow the cable condition monitoring methods and testing techniques provided in Regulatory Guide 1.218 (April 2012).

Acceptance Criteria or Standard - The acceptance criteria is different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables.

For accessible insulated cables and connections installed in adverse, localized environments, the acceptance criteria is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effect may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. In-scope, medium-voltage cables in manholes found to be exposed to significant moisture will be tested as described for inaccessible cables under Method, Frequency and Acceptance Criteria of this program.

For inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific cable to be tested.

Corrective Action - Further investigation by engineering will be performed on accessible and inaccessible insulated cables and connections when the acceptance criteria is not met in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocating or replacement. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Insulated Cables and Connections Aging Management Program. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible cables and connections.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, the initial inspections and tests will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Duke response to SER Open Item 3.9.3 [Reference 24] and Final SER [Reference 2].

18.3.15 Keowee Oil Sampling Program

Purpose - The purpose of the Keowee Oil Sampling Program is to monitor and control the water contamination levels in the Governor Oil System to preclude loss of material for the carbon steel and stainless steel components in the scope of license renewal. In addition, the Keowee Oil Sampling Program manages loss of material of the stainless steel subcomponents in the Turbine Guide Bearing Oil System by monitoring the Turbine Guide Bearing Oil System for water contamination.

Scope - The scope of the Keowee Oil Sampling Program includes all carbon steel and stainless steel components within the scope of license renewal in the Governor Oil System and the turbine guide bearing oil coolers, the only stainless steel component of concern in the Turbine Guide Bearing Oil System. This program contains elements that cover all four Keowee oil systems and, as such, is intended to cover a broader scope than is being credited for license renewal.

Aging Effects - Water contamination in the Governor Oil System can expose the carbon steel and stainless steel components to conditions conducive to loss of material due to various forms of corrosion. Water contamination in the Turbine Guide Bearing Oil System is evidence of leakage of the Turbine Guide Bearing Oil Cooler from loss of material due to microbiologically influenced corrosion of the stainless steel components in the raw water environment of the shell side of the cooler. Monitoring and controlling water contamination precludes this applicable aging effect in the Governor Oil System and manages this applicable aging effect in the Turbine Guide Bearing Oil Coolers.

Method - The Keowee Oil Sampling Program requires that the Governor Oil System Sump and Turbine Guide Bearing Oil System reservoirs be sampled for the presence of water contamination. Results of the analysis are monitored and trended.

Industry Codes or Standards - ASTM D7416-08 or ASTM D6304 provides guidance for the testing of the oil sample.

Frequency - Oil samples are taken and analyzed every six months.

Acceptance Criteria or Standard - No water contamination in excess of 0.1% water by volume is the limit for water contamination in the Governor Oil System and Turbine Guide Bearing Oil System.

Corrective Action - If water contamination levels exceed the acceptance criteria, the accountable engineer will be notified and the source of the water contamination will be located and corrected. The contaminated oil will be sent to the plant oil purifier to remove the water and returned to the system. Specific corrective actions are made in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.16 Penstock Inspection

Purpose - The purpose of the Penstock Inspection is to ensure that the structural integrity of the Keowee Penstock will be maintained.

Scope - The scope of the Penstock Inspection includes both the steel lined and unreinforced concrete lined sections of the Keowee Penstock.

Aging Effects - The applicable aging effects include loss of material, cracking, and change in material properties for the unreinforced concrete lined section and loss of material for the steel lined section of the Keowee Penstock.

Method - The Penstock Inspection requires visual examination of the interior surface of the Keowee Penstock.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed when the Keowee Penstock is dewatered during outages, which is at least every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as identified by the accountable engineer.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service or corrected by repair or replacement. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Penstock Inspection.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Projects and Project Work.

18.3.17 Preventive Maintenance Activities

18.3.17.1 Borated Water Storage Tank Internal Coatings Inspection

A visual inspection of the internal coating of the tank will be performed every third refueling outage or every 6 years with the borated water removed from the tank. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Borated Water Storage Tank Internal Coating Inspection.

18.3.17.2 Chilled Water Refrigeration Unit Preventive Maintenance Activity

The chilled water refrigeration unit condensers are cleaned and eddy current tested once every four years to provide evidence of loss of material. System parameters of the entire refrigeration unit are monitored during operation to provide evidence of fouling. Parameters monitored are monitored quarterly and include inlet and outlet temperatures along with refrigerant pressures. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Chilled Water System Refrigeration Unit Preventive Maintenance Activity.

18.3.17.3 Component Cooler Tubing Examination

Eddy current testing of component cooler tubing is performed approximately every two years. Approximately 100% of the in-service tubes are examined. The acceptance criterion for the inspection is that all tube wall loss indications shall be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Component Cooler Tubing Examination.

18.3.17.4 Condensate Cooler Tubing Examination

Eddy current testing of condensate cooler tubing is performed every 54 months. The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry (approximately 25% of the tubes), are tested. The acceptance criterion for the inspection is that all wall loss indications must be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condensate Cooler Tubing Examination.

18.3.17.5 Condenser Circulating Water System Internal Coatings Inspection

A visual inspection of the interior surfaces of the underground portions of the Condenser Circulating Water System intake and discharge piping is performed every five years. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condenser Circulating Water System Internal Coatings Inspection.

18.3.17.6 Control Room Pressurization and Filtration System Examination

A visual inspection of the exterior surfaces of the Control Room Pressurization and Filtration System components, including seals, sealants, rubber boots, and flexible collars is performed quarterly. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Control Room Pressurization and Filtration System Examination.

18.3.17.7 Decay Heat Cooler Tubing Examination

Eddy current testing of the Decay Heat Cooler tubing is performed every third refueling outage or every 6 years. All of the inservice stainless steel heat exchanger tubes are examined. The acceptance criterion for the inspection is that all wall loss indications are less than 60% through wall. All tubes with wall loss indications greater than or equal to 60% through wall are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Decay Heat Cooler Tubing Examination.

18.3.17.8 Fire Hydrant Flow Test

Fire Hydrant Flow Test is an activity within the Fire Protection Program that was credited in license renewal. (Selected Licensee Commitments apply to other credited portions of the Fire Protection Program.) A flow test of fire hydrants is performed periodically. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all license- renewal related components within the scope of the Fire Hydrant Flow Test.

18.3.17.9 Jacket Water Heat Exchanger Preventive Maintenance Activity

System parameters of the entire Diesel Jacket Water Cooling System (i.e., system operating temperatures, pressures, and expansion tank levels) are monitored during diesel engine operation. Frequency of diesel engine operation is determined by Technical Specification Surveillance Requirement 3.10.1.9. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Jacket Water Heat Exchanger Preventive Maintenance Activity.

18.3.17.10 Keowee Turbine Generator Cooling Water System Strainer Inspection

A visual inspection of the strainer is performed semi-annually on the turbine packing box cooler water strainer and bimonthly on the main inlet strainer. Any noticeable sign of loss of material is documented. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Keowee Turbine Generator Cooling Water System Strainer Inspection.

18.3.17.11 Main Condenser Tubing Examination

Eddy current testing is performed on ten percent of the tubes in one-half of the condenser each refueling outage or every 24 months. Tubes in each half of the condenser are examined every other refueling outage or every 48 months. The acceptance criterion for the examination is that all tubing wall loss indications will be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Main Condenser Tubing Examination.

18.3.17.12 Reactor Building Auxiliary Cooler Inspection

A pressure test and visual inspection for leaks on all four RBAC unit's cooling coils (consisting of four coils per RBAC unit – total of 16 cooling coils) is performed each refueling outage. The

acceptance criteria are no visible leakage resulting from pressure testing. In addition, any indication of loss of material is documented and the need for further analysis determined. No unacceptable loss of material is permitted, as determined by engineering analysis. The RBAC unit's cooling coils are replaced on a periodic basis. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Reactor Building Auxiliary Cooler Inspection.

18.3.17.13 Reactor Building Cooling Unit Tubing Inspection

As required by periodic performance testing, tubes are rodded out and eddy current tested. In addition, the fins are cleaned and visually inspected. The acceptance criterion is any indication of loss of material will be documented and the need for further analysis or visual inspection determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Visual inspection of the ductwork and internal supports is performed on the frequency of the performance testing. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Reactor Building Cooling Unit Inspection.

18.3.17.14 Standby Shutdown Facility Diesel Fuel Oil StorageTank Inspection

A visual inspection of the interior surface of the tank is performed every ten years to monitor evidence of external corrosion due to voids in the external coating. The fuel oil is removed from the tank to perform this inspection. The acceptance criterion is no visual indications of loss of material as determined by Engineering. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Standby Shutdown Facility (SSF) Diesel Fuel Oil Storage Tank Inspection.

18.3.17.15 Standby Shutdown Facility HVAC Coolers Preventive Maintenance Activity

Inlet and outlet temperatures of both coolers as well as refrigerant conditions are monitored every six months. A visual inspection of the copper fins on the air cooling coils is performed every six months. For the water-cooled SSF HVAC condensers, cooling water and air operating temperatures will be within appropriate operating range and refrigerant will be within appropriate specifications. For the air cooling coil, the acceptance criterion is no indications of loss of material of the copper fins. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the SSF HVAC Coolers Preventive Maintenance Activity.

18.3.17.16 Standby Shutdown Facility HVAC Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program

applies to all structures and components within the scope of the Standby Shutdown Facility HVAC Inspection.

18.3.17.17 Reactor Building Cooling System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Reactor Building Cooling System Inspection.

18.3.17.18 Auxiliary Building Ventilation Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Auxiliary Building Ventilation Inspection.

18.3.17.19 Control Room Pressurization and Filtration Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Control Room Pressurization and Filtration Inspection.

18.3.17.20 Penetration Room Ventilation System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in

nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Penetration Room Ventilation System Inspection.

18.3.17.21 Reactor Building Purge System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Reactor Building Purge System Inspection.

18.3.17.22 Keowee Turbine Guide Bearing Oil Cooler Examination

An examination of the internal and external surfaces of each of the Keowee Turbine Guide Bearing Oil Coolers is performed every three years. This Preventive Maintenance Activity inspects, cleans, flushes (shell side) and performs both pressure and Eddy Current testing on each of the heat exchangers including functional verification. If any Asiatic clams are identified, the amount and location are reported. The acceptance criterion is stated in station procedures such that flow will be established for tubes and shell of heat exchanger and the heat exchanger will be free of any leaks. Specific corrective actions are implemented in accordance with Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Keowee Turbine Guide Bearing Oil Cooler Examination.

18.3.17.23 Generator Stator Water Cooler Inspection

The generator stator water coolers are cleaned and inspected (eddy current testing) as defined by the station PM program. The PM requires each cooler to be disassembled, cleaned, and reassembled. Any abnormal conditions identified during cleaning are recorded and evaluated before reassembly occurs. The subsequent eddy current test results are reviewed by engineering to determine whether any tube plugging is required prior to returning the cooler to service. Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the generator stator water cooler inspection.

Regulatory Bases for the preceding Preventive Maintenance Activities:

1. Application [Reference 1].
2. W. R. McCollum Jr., (Duke) letter dated December 14, 1998, to Document Control Desk (NRC), Response to NRC letter dated October 29, 1998, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

3. M. S. Tuckman (Duke) letter dated September 30, 1999, to Document Control Desk (NRC), Amendment 1 - CLB Changes for 1999, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
4. M. S. Tuckman (Duke) letter dated October 15, 1999, to Document Control Desk (NRC), Safety Evaluation Report, Comments and Responses to Open Items and Confirmatory Items, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
5. Final SER [Reference 2].

18.3.18 Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System

Purpose - The purpose of the Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System is to manage the tightness of the interface between the HPI nozzle thermal sleeves and safe ends and to manage the cracking of the piping welds in the normal and emergency HPI portions of the Reactor Coolant System branch lines. This program satisfies the requirements of previous Oconee inspection commitments to the NRC for Generic Letter 85-20 [Reference 25] and IE Bulletin 88-08 [Reference 26], as well as some key ASME Section XI requirements and simplifies the programmatic oversight of these risk-significant welds in the Reactor Coolant System.

Scope - The scope of this program includes the HPI nozzles on the reactor coolant loops and attached Reactor Coolant System piping. The program also applies to the thermal sleeves within the nozzles. It encompasses all Oconee System Piping Class A (not ISI Class A) HPI piping and components with the additions of some welds within Oconee System Piping Class B boundaries (still within ISI Class A scope) being examined in accordance with IE Bulletin 88-08 commitments.

The commitments of Oconee letter from Mr. W. R. McCollum, Jr. to U.S. Nuclear Regulatory Commission of January 7, 1998 on Oconee Nuclear Site, Docket Nos. 50-269, -270, -287, Inservice Inspection Program, Third Yen-Year ISI Interval, GL 85-20 Supplemental Information in answer to the NRC letter from David E. LaBarge to Mr. W. R. McCollum of October 23, 1997, High Pressure Injection System Augmented Inservice Inspection Program - Oconee Nuclear Station Units 1, 2, and 3 (TAC No. M98454) will continue to apply.

Aging Effects - Two aging effects are addressed by this program. The first aging effect is the cracking of the base metal or weld metal which could result in a non-isolable Reactor Coolant System Piping leak.

The second aging effect is the initiation and growth of gaps between the protective thermal sleeve and the nozzle safe end.

Method - This program includes the inspection techniques for these locations defined from ASME Section XI, Subsection IWB defined in the Oconee Inservice Inspection Plan. Additional augmented inspections are done using ultrasonic (UT) and dye- penetrant (PT) inspections of the components of the nozzles and piping to detect cracks, and radiographic (RT) inspections to verify no gaps are growing between the thermal sleeve and the safe end.

The thermal fatigue ultrasonic inspections referenced in this UFSAR Section meet or exceed the requirements of the 1992 Edition, 1993 Addenda of the ASME Code, Section XI, in use during the 3rd In-Service Inspection (ISI) Interval at Oconee. Future Intervals use inspection requirements from Editions/Addenda of the Section XI ASME Code that comply with applicable requirements of 10 CFR 50.55a.

Industry Code or Standard - ASME Section XI for the detection and engineering evaluation of flaws in the welds.

Frequency - The frequency of actions under this program are component location-specific. The frequencies are established for each component location by considering the ASME Section XI inspection frequencies in IWB-2400 as well as the frequencies established by Duke regulatory commitments for Generic Letter 85-20 and IE Bulletin 88-08.

Acceptance Criteria or Standard - For the base metal or weld metal, the acceptance criteria are no flaws in welds and base metal in accordance with ASME Section XI acceptance criteria and no flaws in the nozzle inner radius base metal (which is not required to be inspected under ASME Section XI criteria but which is being inspected under Generic Letter 85-20 commitments in accordance with standards established as a part of the Duke commitment to Generic Letter 85-20).

For the protective thermal sleeve and the nozzle safe end, the acceptance criterion is no increase in size of the gaps between the thermal sleeve and safe end.

Corrective Action - Flaws that can be justified for continued service become time-limited aging analyses and are addressed by the Oconee Thermal Fatigue Management Program. Flaws in weld or base metal that cannot be accepted based on either the geometry screening or the Fracture Mechanics Analysis methods of ASME Section XI are corrected by repair or replacement activities. Unacceptable gaps detected by sleeve RT are corrected by repair or replacement activities. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2]. Specific Duke-NRC communications with regard to NRC Generic Letter 85-20, IE Bulletin 88-08 and Oconee Inservice Inspection Plan provide the regulatory basis for this program. They are:

1. W. R. McCollum, Jr., (Duke) letter dated August 6, 1997 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.
2. W. R. McCollum, Jr., (Duke) letter dated September 10, 1997 to Document control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.
3. H. B. Tucker (Duke) letter dated December 29, 1989 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, -287, Thermal Stresses in Piping Connected to Reactor Coolant System (NRC Bulletin 88-08).

18.3.19 Reactor Vessel Integrity Program

The Oconee Nuclear Station (ONS) Reactor Vessel Integrity Program (RVIP) manages the fracture toughness reduction of the reactor vessel beltline materials for all three Oconee units due to neutron irradiation. The RVIP provides assurance that the Time Limited Aging Analyses (TLAAs) remain valid for the period of extended operation. The major components of the RVIP are the Master Integrated Reactor Vessel Surveillance Program (MIRVP) and the cavity dosimetry and fluence calculations used to establish Pressure Temperature (P-T) and pressurized thermal shock (PTS or RT_{PTS}) limits.

ONS participates in the Master Integrated Reactor Vessel Surveillance Program (MIRVP), which is an NRC approved program [Reference 27] that complies with requirements for an integrated

surveillance program in accordance with 10 CFR 50, Appendix H, Paragraph III.C. The purpose of the MIRVP is to provide a method to monitor reactor pressure vessel beltline materials to determine the reduction of material toughness by neutron irradiation embrittlement. The MIRVP includes base and weld material from the beltline region of the Oconee reactor vessels. The MIRVP provides data for reference temperature (RT) shift calculations used in 10 CFR 50 Appendix G and 10 CFR 50.61, and upper-shelf toughness decrease used in 10 CFR 50 Appendix G and ASME Section XI Appendix K.

ONS also utilizes cavity dosimetry as a continuous fluence monitoring device. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to determine fluence uncertainty values.

Scope of Program

ONS's MIRVP and the RVIP fluence calculations are used to monitor embrittlement of beltline materials in all three ONS reactor vessels through the period of extended operation.

A description of the MIRVP is provided in BAW-1543 [Reference 28] and in BAW-2251A [Reference 29]. Specimens primarily have been irradiated in two B&W reactor vessels (Davis-Besse and Crystal River-3) with some additional irradiations in participating Westinghouse reactor vessels. The fracture toughness specimens are tested in accordance with applicable ASTM standards as identified in Appendix C of BAW-1543.

MIRVP provides reactor vessel material fracture toughness data for the following TLAAs:

- Charpy Upper-Shelf Energy (USE),
- Pressurized Thermal Shock (PTS),
- Reduced Fracture Toughness of RV Materials and Pressure-Temperature (P-T) Limits
- Under clad cracking.

Preventive Actions

The MIRVP and cavity dosimetry are condition monitoring programs and do not rely on preventive actions. However, all modifications to design and operation are reviewed to ensure that any significant changes that affect fluence projections are taken into account, in order to maintain compliance with 10 CFR 50.60, 10 CFR 50 Appendix G, 10 CFR 50 Appendix H, and 10 CFR 50.61.

Parameters Monitored/Inspected

The Cavity Dosimetry exchange is an ONS on-site method to continuously monitor the reactor vessel beltline region neutron fluence which is used in determining the reduction of material toughness. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to determine fluence uncertainty values. Cavity dosimetry is changed out on an as needed basis. Examples of when the cavity dosimetry exchange may be needed are changes in fuel type, pressure-temperature limit updates, and significant changes in fuel loading pattern.

Only the ONS Unit 2 reactor vessel has installed cavity dosimetry. However, the ONS Unit 1 and ONS Unit 3 reactor vessel fluence uncertainty values are based on Oconee Unit 2 cavity dosimetry results due to similar design, fabrication, operation, and fuel loading patterns. The use of the ONS Unit 2 cavity dosimetry for Oconee Unit 1 and Oconee Unit 3 was approved by the NRC in a letter to Duke Power Company dated December 5, 1988 [Reference 53]. Dosimeters are irradiated in the cavity region outside of the ONS Unit 2 reactor vessel. Cavity dosimetry has been irradiated at ONS Unit 2 since cycle 9. The cavity dosimeters are measured to determine the activity resulting from the fast fluence irradiation. In addition,

calculations of the dosimetry activities are performed using operational data. The calculations are compared to the measurements to verify the accuracy and the uncertainty in the calculated fluence. The cavity dosimeters are measured within a frequency such that the fluence uncertainty is kept within the guidance of Regulatory Guide 1.190 [Reference 35].

If modifications to design and operation result in significant changes to neutron energy spectrum, irradiation dose rate, or irradiation temperature (reactor inlet temperature) relative to that discussed in BAW-1543, then the NRC will be notified and a program to determine impact will be proposed.

Detection of Aging Effects

The applicable aging effect is the reduction of material toughness by neutron irradiation embrittlement. These effects are detected by the MIRVP and the cavity dosimetry used for the fluence calculations. The MIRVP meets the requirements of 10 CFR 50, Appendix H, with regard to integrated surveillance programs (Paragraph III.C) and is also an NRC accepted program. The capsule withdrawal schedules are presented in BAW-1543, Supplement 6-A [Reference 32].

MIRVP irradiated material specimen data is used to support reference temperature shift calculations and pressurized thermal shock requirements in accordance with Section 50.61 for the life of the plants.

The reactor vessel fluence and uncertainty calculations provide an accurate prediction of the actual reactor vessel accumulated fast neutron fluence values. The reactor vessel fluence and uncertainty calculations are used as inputs to the pressure-temperature limit curves, upper-shelf energy evaluations, and pressurized thermal shock calculations as well as the surveillance capsule analyses. The cavity dosimetry exchange yields irradiated dosimeters that are analyzed based on Oconee specific geometry models (i.e., fuel, reactor vessel, dosimetry capsule holder, and concrete structures), macroscopic cross sections, cycle-specific sources using the DORT and GIP computer codes, and a reference set of microscopic cross sections (BUGLE Series). Specific attention is made to target fluence values for limiting reactor vessel beltline weld material locations. Fluence and uncertainty calculations typically follow each cavity dosimetry analysis depending on the need. The frequency of updating fluence and uncertainty calculations change as additional data are obtained.

Monitoring and Trending

The applicable specimens removed from the MIRVP surveillance capsules are utilized to determine the adjusted reference temperature for the pressure-temperature limits (10 CFR 50, Appendix G, Section IV.A), and RT_{PTS} values (10 CFR 50.61(c)(2)). Applicable reactor vessel fracture toughness data is assessed and MIRVP TLAAs updated when required.

The USE and PTS TLAAs include for end-of-license fluence projections obtained from irradiated material properties. However, P-T limits are updated prior to exceeding the calculated time period (based on projected fluence values) and may be developed for less than the end-of-life. TLAAs are valid for periods of time expressed in effective full power years (EFPY). Periodically they may require updating based on changes to assumptions used in the analysis (e.g., revised accumulated fluence projections, significant operational changes such as uprates, and to incorporate methodology or regulatory changes). The rules and guidance governing TLAA inputs are contained in 10 CFR 50 Appendix G, 10 CFR 50 Appendix H, 10 CFR 50.61, Regulatory Guide 1.99 Rev. 2 [Reference 31], Regulatory Guide 1.190, ASME Section XI Appendix K, ASME Section XI Appendix G [Reference 37], ASME Section XI Appendix E, and ASTM E185-82 [Reference 30].

The ONS TLAA for upper shelf energy (USE) was performed using Reg. Guide 1.99 Rev. 2 Position 1.2 and predicted that the Charpy USE values fell below 50 ft-lbs for all Oconee beltline welds on each unit except for one weld on Unit 1. An equivalent margin analysis (EMA) was performed in BAW-2275A [Reference 54] per ASME Section XI Appendix K demonstrating a margin of safety against fracture that is equivalent to those required by Appendix G of ASME Section XI.

Acceptance Criteria

The data from MIRVP are used for RV embrittlement projections to comply with 10 CFR 50, Appendix G requirements and 10 CFR 50.61 limits through the period of extended operation.

The results of the fluence uncertainty values are to be within the NRC-recommended limit of ± 20%. Calculated fluence values for fluence levels greater than 1.0 MeV are compared with measurement values from the cavity dosimetry to determine if calculations contain any unexplained deviations. This methodology represents a continuous validation process to ensure that no unexplained deviations have been introduced, and that the uncertainties remain comparable to the reference benchmarks.

Modifications to core design and operation that result in significant changes to the neutron energy spectrum, gamma heating, or reactor vessel inlet temperature discussed in BAW-1543 [Reference 28] will be evaluated prior to implementation as part of the modification process. Any subsequent impact on the applicable embrittlement evaluations will be assessed, and changes to the TLAAs will be submitted to the NRC using the appropriate licensing process.

Pressure-temperature limit curves are generated in accordance with the requirements of 10 CFR 50, Appendix G. NRC approved pressure-temperature limit curves must be in place for continued plant operation.

Calculations of RT for pressurized thermal shock (RT_{PTS}) should be below the screening criteria of 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds, respectively, in accordance with 10 CFR 50.61.

Corrective Actions

If the MIRVP provides data that affects ONS's TLAA in meeting 10 CFR 50 Appendix G and 10 CFR 50.61 requirements, specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program (QAP).

As additional cavity dosimetry is withdrawn and tested, cavity dosimetry exchange frequency may be adjusted, as appropriate. If the comparison of calculations to measurements of the Unit 2 multiple dosimeters fail to meet ± 20%, measurements and calculations will be reviewed to locate the discrepancy.

As additional cavity dosimetry is withdrawn and tested, fluence and uncertainty calculations will be revised and updated accordingly. If comparisons of the dosimetry calculations to measurements are not within acceptance standards, then specific corrective actions will be implemented in accordance with the Duke QAP.

Oconee Improved Technical Specifications (ITS) 3.4.3, RCS Pressure and Temperature (P/T) Limits, require valid pressure-temperature limits prior to and during plant operations. Actions to be taken if the pressure-temperature limits are exceeded are specified in Oconee ITS 3.4.3, specific corrective actions will be implemented in accordance with the Duke QAP.

Confirmation Process and Administrative Controls

ONS has an established 10 CFR 50, Appendix B Program described in Duke Energy Topical Report Duke-1-A, "Quality Assurance Program" which addresses the elements of corrective

actions, confirmation process, and administrative controls. Quality Assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B.

Operating Experience

Applicable operating experience is reviewed in accordance with the Duke Energy Operating Experience Program. Relevant operating experience will be entered into the Corrective Action Program to evaluate and address potential changes. This ongoing operating experience evaluation process helps ensure Reactor Vessel Integrity Program effectiveness.

18.3.19.1 Deleted Per 2014 Update

18.3.19.2 Deleted Per 2014 Update

18.3.19.3 Deleted Per 2014 Update

18.3.19.4 Deleted Per 2014 Update

18.3.19.5 Deleted Per 2014 Update

18.3.20 Reactor Vessel Internals Inspection

Purpose - The purpose of the Reactor Vessel Internals Inspection is to inspect and examine the condition of reactor vessel internals items in order to assure that the applicable aging effects will not result in loss of the intended functions of the reactor vessel internals during the period of extended operation.

Scope - The scope of this inspection consists of the reactor vessel internals stainless steel items for Oconee Units 1, 2 and 3. For inspection purposes, these items can be separated into four groups - (1) items comprised of plates, forgings, and welds, (2) baffle bolts, (3) core barrel bolts and thermal shield bolts, and (4) items fabricated from cast austenitic stainless steel (CASS) and martensitic steel. More specifically, the items fabricated from CASS and martensitic steel include control rod guide tube spacers, vent valve bodies, Unit 3 outlet nozzles, and incore guide tube assembly spiders. The vent valve retaining rings, fabricated from martensitic stainless steel, are also included in this inspection.

Aging Effects - The applicable aging effects for items comprised of plates, forgings, and welds are cracking due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation embrittlement, and dimensional changes due to void swelling.

The applicable aging effects for baffle bolts are cracking due to irradiation assisted stress corrosion, reduction of fracture toughness due to irradiation embrittlement, and dimensional changes due to void swelling.

The applicable aging effects for items comprised of core barrel bolts, and thermal shield bolts are cracking due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation embrittlement, and loss of bolted closure integrity due to stress relaxation.

The applicable aging effects for item fabricated from CASS and martensitic steel are reduction of fracture toughness by thermal embrittlement and irradiation embrittlement.

Method - Current plans are to perform a visual inspection of the items comprised of plates, forgings, and welds. Activities are in progress to develop and qualify the inspection method.

Current plans are to perform a volumetric inspection of the baffle bolts. Activities are in progress to develop and qualify the inspection method.

Current plans are to perform a visual inspection of core barrel bolts and thermal shield bolts. Activities are in progress to determine if volumetric examinations will be required.

For items fabricated from CASS and martensitic steel, an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items will be performed. The specific inspection method will depend on the results of these analyses. The Oconee Unit 3 outlet nozzles will be inspected if the results of the analysis indicate such inspection is necessary.

Should data or evaluations indicate that the above inspections can be modified or eliminated, Duke will provide plant-specific justification to demonstrate the basis for the modification or elimination.

Sample Size - The sample size for the inspection of each Oconee unit will be determined as part of the development of the inspection method.

Industry Codes or Standards - No code or standard currently exists to guide or govern this inspection.

Frequency - The Reactor Vessel Internals Inspection will be performed once on each set of reactor vessel internals during the twenty-year period of extended operation. Preparation for these inspections will include unit selection and proper sequencing of the inspections as well as the opportunity to develop a lead unit for these inspections.

Acceptance Criteria or Standard - For the items comprised of plates, forgings, and welds that will be visually inspected, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed prior to the inspection.

For baffle bolts, any detectable crack indication is unacceptable for a particular baffle bolt. The number of baffle bolts needed to be intact and their locations will be determined by analysis. Acceptance criteria for dimensional changes due to void swelling will be developed prior to the inspection.

For core barrel bolts, and thermal shield bolts any detectable crack is unacceptable. Acceptance criteria for all aging effects will be developed prior to the inspection.

For items fabricated from CASS and martensitic steel, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed prior to the inspection.

Corrective Action - If the results of the inspection are not acceptable, then actions will be taken to repair or replace the affected items or to determine by analysis the acceptability of the items. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The inspections among the three sets of reactor vessel internals will be spaced out over the twenty-year period of extended operation. The first inspection will occur early in the period. The second will occur near the middle of the period, and the third will occur in the latter third of the twenty-year period. (The third inspection will be scheduled prior to the last year of the twenty-year period of extended operation for the unit inspected.)

Regulatory Basis - Renewal Applicant Action Item 4.1 (Items 5, 6, 7, 8, and 9) in the Safety Evaluation Report for BAW-2248A. Duke letter dated December 17, 1999 [Reference 39], and Final SER [Reference 2].

18.3.21 Service Water Piping Corrosion Program

Purpose - The purpose of the Service Water Piping Corrosion Program is to assess and manage loss of material due to corrosion for the various component materials in Oconee, Keowee and Standby Shutdown Facility raw water systems and selected Keowee air and gas systems that may challenge the component intended function of pressure boundary. The following raw water systems within the scope of license renewal are within the scope of the Service Water Piping Corrosion Program:

1. Protected Service Water System,
2. Chilled Water System (raw water portion of the coolers),
3. Component Cooling System (raw water side of the component coolers),
4. Condenser Circulating Water System,
5. Diesel Jacket Water Cooling System (raw water side of the heat exchangers),
6. Essential Siphon Vacuum System,
7. High Pressure Service Water System,
8. Keowee Service Water System,
9. Keowee Turbine Generator Cooling Water System,
10. Keowee Turbine Sump Pump System,
11. Keowee Vacuum Break System,
12. Low Pressure Injection System (for the raw water side of the Decay Heat Cooler),
13. Low Pressure Service Water System,
14. Siphon Seal Water System,
15. SSF Auxiliary Service Water System,
16. Keowee Carbon Dioxide System,
17. Keowee Governor Air System.

Scope - The Service Water Piping Corrosion Program is credited for license renewal for managing loss of material of copper, brass, bronze, carbon steel, cast iron and stainless steel components in the license renewal portions of the systems listed in the Purpose. The program includes the inspection of carbon steel and brass piping components exposed to raw water which are more susceptible to general corrosion and which serve as a leading indicator of the general material condition of the system components. As a result of the One-Time Inspection activity during License Renewal Implementation, the Keowee Air and Gas Systems [UFSAR Section 18.2.3] were added to the Service Water Piping Corrosion Program.

Over 30 different carbon steel piping component inspection locations have been established throughout the applicable systems based on the understanding that fluid flow rates are a prime contributor to the conditions conducive to corrosion. The Service Water Piping Corrosion Program is not focused on components within each specific system, but is more broadly focused across all of the system components within license renewal that are susceptible to the

various corrosion mechanisms. The intent of the Service Water Piping Corrosion Program is to inspect a number of locations with conditions that are characteristic of the conditions found throughout the raw water systems above. The results of these inspection locations are then extrapolated to similar locations throughout all the raw water systems within the scope of license renewal. This characteristic-based approach recognizes the commonality among the component materials of construction and the environment to which they are exposed. In this way components within the raw water systems at Keowee are linked to the results of the inspections of other raw water systems at Oconee and the Standby Shutdown Facility.

As an example, the inspection results of a carbon steel pipe in a stagnant location in the Low Pressure Service Water System at Oconee would be indicative of the condition of a carbon steel pipe in a stagnant location in the Turbine Generator Cooling Water System at Keowee. Both systems have carbon steel pipe in a stagnant location exposed to raw water from Lake Keowee. Both have operated a similar length of time under similar conditions. Therefore, the inspection results of the carbon steel pipe in the Low Pressure Service Water System will be characteristic of the condition of the carbon steel pipe in the Turbine Generator Cooling Water System at Keowee.

This characteristic-based approach to managing aging effects is also used for materials that behave similarly, but are not constructed from the same material specification. For example, due to the similarity between cast iron and carbon steel, operating experience has shown that the corrosion performance of cast irons and carbon steels is very similar. Monitoring of carbon steel piping for loss of material would serve as an indicator of the condition of the cast iron components in the raw water systems. Corroded carbon steel piping would be an indicator of corroded cast iron components.

Another example of materials that will behave similarly when exposed to raw water are copper, brass and bronze. Since copper and bronze are, in general, more corrosion resistatnt than brass to natural waters, an inspection location in brass piping in Keowee raw water systems will serve as an indicator of the condition of brass, bronze, and copper components exposed to raw water in other systems at Keowee, Oconee and the Standby Shutdown Facility.

Aging Effects - The aging effects of concern in raw water systems are loss of material due to general corrosion of copper, bronze, brass, carbon steel, and cast iron components, loss of material due to galvanic corrosion at the junction of carbon steel and stainless steel components, and loss of material due to localized corrosion for copper, bronze, brass, carbon steel, cast iron and stainless steel that may reveal itself in the raw water systems within the scope of license renewal. For the Keowee Carbon Dioxide and Keowee Governor Air systems, the aging effect is loss of material due to general corrosion of carbon steel components.

Method - Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing. Also, visual examination is used as a general characterization tool in conjunction with ultrasonic testing when access to interior surfaces is allowed such as during plant modifications.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability is judged in accordance with the component design code of record.

Frequency - Because the corrosion phenomena is slow-acting, inspection frequency varies for each location with a periodicity on the order of five to ten years. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events and plant operating experiences.

Acceptance Criteria - No inspection locations falling below the minimum pipe wall thickness values for the inspection locations as defined in the program. These minimum values have been determined based on design pressure or structural loading using the piping design code of record and then applying additional conservatism.

Corrective Action - Inspection locations that fall below the acceptance criteria are repaired or replaced prior to the system returning to service unless an engineering analysis allows further operation. In the cases where a component may be allowed to continue in service, a re-inspection interval is established in the program.

Specific corrective actions are implemented in accordance with the Problem Investigation Program. The Problem Investigation Program applies to all structures and components within the scope of the Service Water Piping Corrosion Program.

Regulatory Basis - The Service Water Piping Corrosion Program is a formalization of a portion of the commitments made in response to GL 89-13, primarily those associated with component pressure boundary maintenance [References 19, 20, 21, 22, and 23]; Application [Reference 1] and Final SER [Reference 2].

18.3.22 System Performance Testing Activities

The following raw water systems have been identified as containing smaller diameter piping that could be affected by fouling and will be managed by System Performance Testing Activities:

1. Protected Service Water System,
2. Keowee Turbine Generator Cooling Water System,
3. Keowee Turbine Sump Pump System,
4. Low Pressure Service Water System,
5. Siphon Seal Water System, and
6. SSF Auxiliary Service Water System.
7. Essential Siphon Vacuum System.

Performance testing for these systems will provide assurance that the components are capable of delivering adequate flow at a sufficient pressure as required to meet system and accident load demands. Performance testing includes other alternate techniques, for example, periodic monitoring of system operating parameters, for those systems whose design or operation renders conventional testing techniques unfeasible. For the Keowee Turbine Generator Cooling Water system, monitoring or bearing temperatures is acceptable.

Periodic operation, inspections and testing are completed for the above systems at a range of frequencies. The Turbine Generator Cooling Water System is operated at design conditions every time the Keowee units operate with bearing temperatures monitored during operations. For other systems, periodic testing frequencies range from quarterly to every third refueling outage, depending on the system. Fouling is not a concern in the Essential Siphon Vacuum System since the system is primarily an air system, and any raw water intrusion is insufficient to allow for fouling.

System performance is determined and compared to test acceptance criteria established by engineering. The results of visual inspections are evaluated by engineering. If the results of the tests and inspections do not meet acceptance criteria, then corrective actions, which could require piping replacement, are undertaken. Specific corrective actions are implemented in

accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the System Performance Testing Activities.

The activities credited here for license renewal are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 19, 20, 21, 22 and 23].

The continued implementation of the System Performance Testing Activities provides reasonable assurance that the aging effects will be managed such that mechanical components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.23 Tendon - Secondary Shield Wall - Surveillance Program

Purpose - The purpose of the Tendon - Secondary Shield Wall - Surveillance Program is to inspect the Secondary Shield Wall Post-Tension Tendon System to ensure that the quality and structural performance of the secondary shield wall is consistent with the licensing basis.

Scope - The scope of this program includes the tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, bushing, buttonheads, and shims of the Units 1, 2, and 3 Secondary Shield Wall Tendons.

Aging Effects - The applicable aging effects include loss of material due to corrosion and cracking of tendon anchorage; wire force relaxation; loss of material due to corrosion and breakage of wires; loss of material due to corrosion and cracking of bearing plate; cracked, split, and broken buttonheads; cracking and loss of material due to corrosion of shims.

Method - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons.

Industry Code or Standard - No code or standard exists to guide or govern this program.

Frequency - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons every other refueling outage or every 48 months.

Acceptance Criteria or Standard - No unacceptable visual indication of moisture, discoloration, foreign matter, rust, corrosion, splits or cracks in the buttonheads, broken or missing wires, and other obvious damage as identified by the accountable engineer. Lift-off forces are measured and compared to established acceptance criteria. The minimum required forces for the tendon groups range from 390 kips to 560 kips depending on the location of the group.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. Specific corrective actions are implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.24 230 kV Keowee Transmission Line Inspection

Purpose - The purpose of the 230 kV Keowee Transmission Line Inspection is to maintain the structural integrity of the 230 kV Keowee transmission line structures.

Scope - The 230 kV Keowee Transmission Line Inspection includes steel towers, concrete foundations, and hardware within the 230 kV Keowee transmission line.

Aging Effects - The applicable aging effects of concern include loss of material due to corrosion of the steel structures and loss of material due to spalling or scaling for concrete components.

Method - The inspection requires a visual examination of the towers.

Industry Code or Standard - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines; Rule 214 Inspection and Tests of Lines and Equipment.

Frequency - The inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as evaluated by the inspector.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the 230 kV Keowee Transmission Line Inspection.

Regulatory Basis - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines, Rule 214 Inspection and Tests of Lines and Equipment, Application [Reference 1] and Final SER [Reference 2].

18.3.25 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for inspection of each reactor coolant pump flywheel. At approximately three-year intervals, the bore and keyway of each reactor coolant pump flywheel shall be subject to an in-place, volumetric examination. If maintenance or repair activities necessitate flywheel removal, and if the interval measured from the previous such inspections is greater than 6-2/3 years, a surface examination of exposed surfaces and a complete volumetric examination are required. Results of the examinations will be evaluated by the original acceptance criteria and compared with the original examination data to assure the absence of unacceptable defects. The interval may be extended up to one year to permit inspections to coincide with planned outage.

18.3.26 Battery Rack Inspections

Purpose - The purpose of the Battery Rack Inspections is to ensure that the structural integrity of the battery racks is maintained.

Scope - The scope of the Battery Rack Inspections include racks for 125 VDC instrumentation and control batteries at Keowee, 125 VDC 230 kV switchyard batteries, 125 VDC instrument and control batteries in the Auxiliary buildings, and 125 VDC instrument and control batteries in the SSF.

Aging Effect - Battery racks are inspected for physical damage or abnormal deterioration, including loss of material due to corrosion.

Method - The inspection requires a visual inspection of the surfaces of the battery racks.

Industry Code or Standard - NUREG-1430, Standard Technical Specifications-Babcock and Wilcox Plants, Revision 1, April 1995; IEEE450, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations.

Frequency - The inspection is performed annually as required by the Oconee Improved Technical Specifications. This surveillance frequency is consistent with the recommendation to check the structural integrity of the battery rack on a yearly basis per IEEE-450.

Acceptance Criteria or Standard - No visual indication of loss of material due to corrosion. The presence of physical damage or deterioration does not necessarily represent a failure, provided an evaluation determines that the physical damage or deterioration does not affect the ability of the battery to perform its function.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented by the Problem Investigation Program and in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Oconee improved Technical Specifications SR 3.8.1.11, AC Sources Operating, SR 3.8.3.3, DC Sources Operating and SR 3.10.1.10, Standby Shutdown Facility.

18.3.27 Steam Generator (SG) Program

The purpose of the Steam Generator (SG) Program is to provide comprehensive examinations of the steam generator tubes to ensure that degradation of the tubes is identified and corrective actions taken prior to exceeding allowable limits. The scope of the Steam Generator (SG) Program includes all steam generator tubes in each steam generator. The aging effects managed by the Steam Generator (SG) Program include loss of material, cracking, and mechanical distortion. The method of examination is specified in Oconee TS 5.5.10 Steam Generator (SG) Program. The Steam Generator (SG) Program complies with the guidance provided in NEI 97-06, Steam Generator Program Guidelines, and its referenced industry guideline documents for inspections, personnel qualification, and technique qualification. The frequency of examinations is specified in Oconee TS 5.5.10, Steam Generator (SG) Program. Acceptance criteria are specified in Oconee TS 5.5.10, Steam Generator (SG) Program. The Duke Energy Steam Generator Management Program Manual provides corrective action directions. Specific corrective actions will be implemented in accordance with the Duke Energy Quality Assurance Program. The Steam Generator (SG) Program is implemented by written procedures as required by Oconee TS 5.4 and the Duke Energy Quality Assurance Program. The regulatory basis for the Steam Generator (SG) Program is Oconee TS 5.5.10.

18.3.28 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.

2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

3. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Attachment 1, Pages 43-48, Response to Requests for Additional Information, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

4. W. T. Russell (NRC) letter dated November 19, 1993 to W. H. Rasin (NUMARC, now NEI).

5. M. S. Tuckman (Duke) letter dated July 30, 1997 to Document Control Desk (NRC), Oconee Nuclear Station - Response to Generic Letter 97-01: *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,* Docket Nos. 50-269, -270, and -287.

6. ANSI B30.2.0, "Overhead and Gantry Cranes", American National Standard, Section 2-2, *Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks and Slings,* The American Society of Mechanical Engineers, New York.
7. ANSI B30.16, "Overhead Hoists (Underhung)", The American Society of Mechanical Engineers, New York.
8. 29 CFR Chapter XVII, 1910.179, *Occupational Safety and Health Administration, Overhead and Gantry Cranes.*
9. W. R. McCollum, Jr. (Duke) letter dated February 8, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information (RAI), Attachment 1, Response to RAI 4.12-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
10. 18 CFR Part 12 - *Safety of Water Power Projects and Project Works,* 59 FR 54815, Nov. 2, 1994.
11. IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants.*
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18. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
19. H. B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
20. H. B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
21. J. W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, - 270, and -287.

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27. D. B. Matthews (NRC) letter dated July 11, 1997 to J. H. Taylor (FTI), Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group Report BAW-1543, Revision 4, Supplement 2, Supplement to the Master Integrated Reactor Vessel Surveillance Program, TAC No. M98089.
28. BAW-1543, Revision 4, *Master Integrated Reactor Vessel Surveillance Program,* prepared for B&W Owners Group by B&W Nuclear Technologies, Inc., February 1993.
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31. Regulatory Guide 1.99, Revision 2, NRC, *Radiation Embrittlement of Reactor Vessel Materials,* May 1998.
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34. M. S. Tuckman (Duke) letter dated May 10, 1999, to Document Control Desk (NRC), Response to Requests for Additional Information, Attachment 1, Response to Potential Open Item 3.4.5-9, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
35. Regulatory Guide – 1.190, *Calculational and Dosimetry Method for Determining Pressure Vessel Neutron Fluence,* March 2001.
36. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June 1998).
37. ASME Section XI, Appendix G for Nuclear Power Plants, Division 1, *Protection Against Non-Ductile Failure.*
38. ASME Code Case N-514, *Low Temperature Overpressure Protection,* Section XI, Division 1.
39. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Items 3.4.3.3-3,

3.4.3.3-4, and 3.4.3.3-5, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

40. NRC Bulletin 2003-02, "Leakage from Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," August 21, 2003.
41. NRC Order EA-03-009, "Issuance of first revised NRC Order (EA-03-009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," February 20, 2004.
42. NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRS," May 28, 2004.
43. Barron, Henry B. (Duke) to U. S. Nuclear Regulatory Commission, Duke Response to NRC Bulletin 2004-01, July 27, 2004.
44. McCollum, William R. (Duke) to U. S. Nuclear Regulatory Commission, Supplement to Response to NRC Bulletin 2004-01, September 21, 2004.
45. Barret, R. (NRC) to Marion, A. (NEI), Flaw Evaluation Guidelines, April 11, 2003.
46. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzle Having Pressure Retaining Partial-Penetration Welds", March 28, 2006.
47. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-772-1, "Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated With Alloy 600/82/182 Materials." January 26, 2009.
48. Federal Register 10CFR Part 50, "Industry Codes and Standards; Amended Requirements; Final Rule, Wednesday September 10, 2008 – pages 52742 and 52749."
49. Material Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline (MRP-139), EPRI Report 1010087, Revision 1, December 2008.
50. License Amendment No. 373, 375, and 374 for Units 1, 2, and 3 respectively (date of issuance June 27, 2011) - Use of Fiber Reinforced polymer on masonry brick walls for the mitigation of differential pressure created by highwinds.
51. PD-EG-PWR-1611, Boric Acid Corrosion Control Program (Program Description), Rev. 0.
52. AD-EG-PWR-1611, Boric Acid Corrosion Control Program - Implementation (Administrative Procedure), Rev. 0.
53. D. B. Matthews (NRC) letter dated December 5, 1988 to H.B. Tucker (Duke), Subject: "Cavity Dosimetry Program", Oconee Nuclear Station Units 1, 2, and 3 (TAC 65759, 65760, 65761), Docket Nos. 50-269, 50-270, 50-287.
54. BAW-2275A, "Low Upper-Shelf Toughness Fracture Mechanics Analsyis of B&W Designed Reactor Vessels for 48 EFPY", August 1999.
55. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-770-1, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzel Butt Welds Fabricated With UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities." December 25, 2009.

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18.4 Additional Commitments

The following are additional commitments that are not identified in the preceding sections of Chapter 18.

"HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED"

1. *A plant-specific analysis will be performed to demonstrate that, under loss-of-coolant-accident (LOCA) and seismic loading, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and that irradiation accumulated at the expiration of the renewal license will not adversely affect deformation limits. Data will be developed to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license. (Reference: Duke letter to the NRC dated December 17, 1999, Attachment 1, page 8)*

   Duke submitted the plant-specific time limited aging analysis (ML 12053A332) to the NRC for review on February 20, 2012 and received a Safety Evaluation (ML 13045A489) from the NRC on February 19, 2013. During NRC evaluation there was a request for additional information (RAI) from the NRC and a teleconference was held between the NRC and Duke Energy. The response to the RAI is documented in ML 12333A317 and a summary of the teleconference is contained in ML 13024A265.

2. For the Steam Generator (SG) Program see Section 18.3.27.

3. Table 5-24, Table 5-25, Table 5-26, Table 5-27, Table 5-28, and Table 5-29 of the UFSAR contain reactor vessel materials data. These tables will be revised to include the current data from BAW-2325 (Revision 1 or the most current revision available) by July 1, 2001. (Reference: Duke letter to NRC dated March 27, 2000, Submittal of UFSAR Supplement, March 2000)

4. The Oconee Thermal Fatigue Management Program will be modified to incorporate a plant-specific resolution of Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." Plant-specific actions will be taken either in the manner that was described in Duke letter to the NRC dated October 15, 1999, "Safety Evaluation Report - Oconee Nuclear Station License Renewal Application, Comments and Responses to Open Items and Confirmatory Items, Response to Open Item 4.2.3-2," or by using another approach that is acceptable to the NRC staff. (Reference: Duke letter to NRC dated October 15, 1999, Attachment 2, page 111)

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