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2CAN080401

August 18, 2004

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Subject: License Renewal Application Clarifications
TAC No. MB8402
Arkansas Nuclear One – Unit 2
Docket No. 50-368
License No. NPF-6

Dear Sir or Madam:

During a meeting with the NRC on July 20, 2004, the Staff requested clarifications to several of the previously docketed requests for additional information (RAI) responses for the Arkansas Nuclear One, Unit 2 (ANO-2) License Renewal Application (LRA). These clarifications are contained in Attachment 1.

New commitments contained in this submittal are summarized in Attachment 2. Should you have any questions concerning this submittal, please contact Ms. Natalie Mosher at (479) 858-4635.

I declare under penalty of perjury that the foregoing is true and correct. Executed on August 18, 2004.

Sincerely,

Dale E. James
Acting Director, Nuclear Safety Assurance

DEJ/nbm

Attachments

A100

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Attachment 1

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LRA Clarifications

LRA Clarifications

RAI 2.4-2 Clarification: The Staff requested Entergy to identify any thermal insulation at ANO-2 that serves an intended function in accordance with 10CFR54.4(a)(1), 10CFR54.4(a)(2), or 10CFR54.4(a)(3), describe plant-specific operating experience related to degradation of thermal insulation in general and thermal insulation that serves an intended function, and describe the scoping and screening evaluation for thermal insulation that serves an intended function, including the technical basis for either inclusion within or exclusion from the scope of license renewal. The Staff indicated that the focus of the requested clarification was insulation on hot containment piping penetrations.

Response: The insulation on hot containment piping penetrations is not required to ensure the functions of 10CFR54.4(a)(1) are accomplished or to demonstrate compliance with Commission regulations identified in 10CFR54.4(a)(3). The insulation does not meet 10CFR54.4(a)(2) as its failure will not prevent satisfactory accomplishment of any of the functions identified in 10CFR54.4(a)(1). Insulation on hot piping at containment penetrations does support normal ventilation systems in maintaining the environment for surrounding structural elements. However, maintaining the environment during normal operation is not an intended function identified in 10CFR54.4(a)(1). The fact that normal ventilation systems are not in the scope of license renewal supports this conclusion. In summary, thermal insulation on hot piping at containment penetration does not meet the scoping criteria of 10CFR54.4. This is consistent with the previously approved staff position documented in the safety evaluation report (SER) related to the license renewal of North Anna and Surry power stations, NUREG-1766, Section 2.1.3.1.

Notwithstanding the above, Entergy performed an aging management review of the insulation on hot containment piping penetrations for ANO-2 even though it is not considered in the scope of license renewal. The aging management review did not identify any aging effects requiring management. ANO-2 hot piping penetration insulation is protected by its installation indoors in the annulus between the penetration piping and the penetration sleeve. The review of plant-specific operating experience for license renewal identified no age-related degradation of thermal insulation indoors, including insulation on hot piping at containment penetrations.

RAI 3.5-5 Clarification: The Staff requested Entergy to consider periodic monitoring of groundwater chemistry in the future to assure that there is no significant change in groundwater chemistry and to perform a one-time inspection/monitoring before entering the period of extended operation.

Response: Wells are no longer available for sampling groundwater. Consequently, in lieu of sampling groundwater to confirm that it remains non-aggressive, concrete exposed to groundwater is included in the Structures Monitoring Program for inspection to confirm the absence of aging effects. Under the Structures Monitoring Program, concrete exposed to lake water is periodically inspected. Since lake water chemistry is representative of groundwater chemistry, results of these inspections will be representative of underground concrete exposed to groundwater. In addition, when excavated for maintenance activities, inaccessible concrete exposed to groundwater will be visually inspected under the Structures Monitoring Program.

<u>RAI 3.5-9 Clarification</u>: The Staff requested Entergy to demonstrate why the intake canal does not need an aging management program. The Staff also stated that the intake canal being qualified as seismic Category 1 further demonstrates that it needs an aging management program.

<u>Response</u>: The circulating water system for ANO-1 is supplied by the intake canal. The ANO-2 systems that utilize the intake canal as a suction source are the service water and fire protection systems. The intake canal is qualified as seismic Category 1 because it supports emergency operation of ANO-1. The intake canal was conservatively included in the scope of license renewal for ANO-2 and subject to aging management review because it provides an alternate suction source (in addition to the emergency cooling pond) for the service water and fire protection systems.

The intake canal has been in service for over 30 years with no aging effects or degradation that has threatened its capability to provide the required circulating water flow to ANO-1. It has engineered slopes with adequate vegetation to limit erosion caused by wind. Degradation due to flooding has not been a problem. There are no aging effects for the intake canal that would result in not being able to supply the minimum required flow for ANO-2, which is a small fraction of the required flow for ANO-1 circulating water.

In summary, the aging management review did not identify aging effects requiring management for the intake canal. This is consistent with the previously approved Staff position documented in NUREG-1743, SER related to the License Renewal of ANO-1. Notwithstanding the above, the intake canal is periodically inspected as part of the ANO Maintenance Rule Program. Periodic inspections will continue into the period of extended operation.

<u>RAI 4.5-2 Clarification</u>: The Staff requested Entergy to propose a plan or a program that would provide a valid time-limited aging analysis (TLAA) for each group of tendons in the ANO-2 containment.

<u>Response</u>: Consistent with 10CFR54.21(c)(1)(iii), loss of tendon prestress will be adequately managed during the period of extended operation by continued implementation of tendon inspections required by the American Society of Mechanical Engineers (ASME) Code Section XI IWL. In accordance with NUREG 1800, Section 4.5.3.1.3, relevant operating experience, including experience with prestressing systems described in NRC Information Notice (IN) 99-10, will be considered during inspections and data analysis. Prior to the period of extended operation, trend lines for ANO-2 tendon prestressing forces will be developed using regression analysis in accordance with guidance provided in NRC IN 99-10. If future tendon examination data diverge from the expected trend, the discrepancy will be addressed in accordance with requirements of the Containment Inservice Inspection (ISI) Program (IWE/IWL) and the current licensing basis.

In summary, the ANO-2 Containment ISI Program in accordance with the requirements of ASME Code Section XI IWL will provide reasonable assurance that the effects of aging on the intended functions of tendons will be adequately managed for the period of extended operation in accordance with the provisions of 10CFR54.21(c)(1)(iii).

RAI 2.5-2 Clarification: The Staff requested Entergy to include a second offsite power source for SBO recovery as discussed in ISG-2.

Additional Response: Entergy included in the scope of license renewal only the ANO-2 offsite power components required for SBO recovery, which included the connections from Startup 3 to Switchyard Breaker B0126. During a meeting with the Staff on July 20, 2004, the Staff requested that Entergy include a second offsite power source in the scope of license renewal. The second offsite power source is an ANO-1 component credited for General Design Criterion (GDC) 17. Entergy agreed to consider the second source, Startup Transformer #2, in the scope of license renewal and subject to aging management review.

As stated in the ANO-2 Safety Analysis Report (SAR) Section 8.1.4, ANO-2 can supply electric power to the onsite electric distribution system from two physically independent transmission network circuits, Startup Transformer #3, which is an ANO-2 offsite power component, and Startup Transformer #2, which is an ANO-1 offsite power component. Startup Transformer #3 is supplied by the switchyard autotransformer bank through underground cables, which have been addressed for license renewal. Startup Transformer #2 is supplied by the 161kV switchyard ring bus.

With inclusion of the alternate path for SBO recovery, a description of Startup Transformer #2 and the connection to the 161kV switchyard is provided.

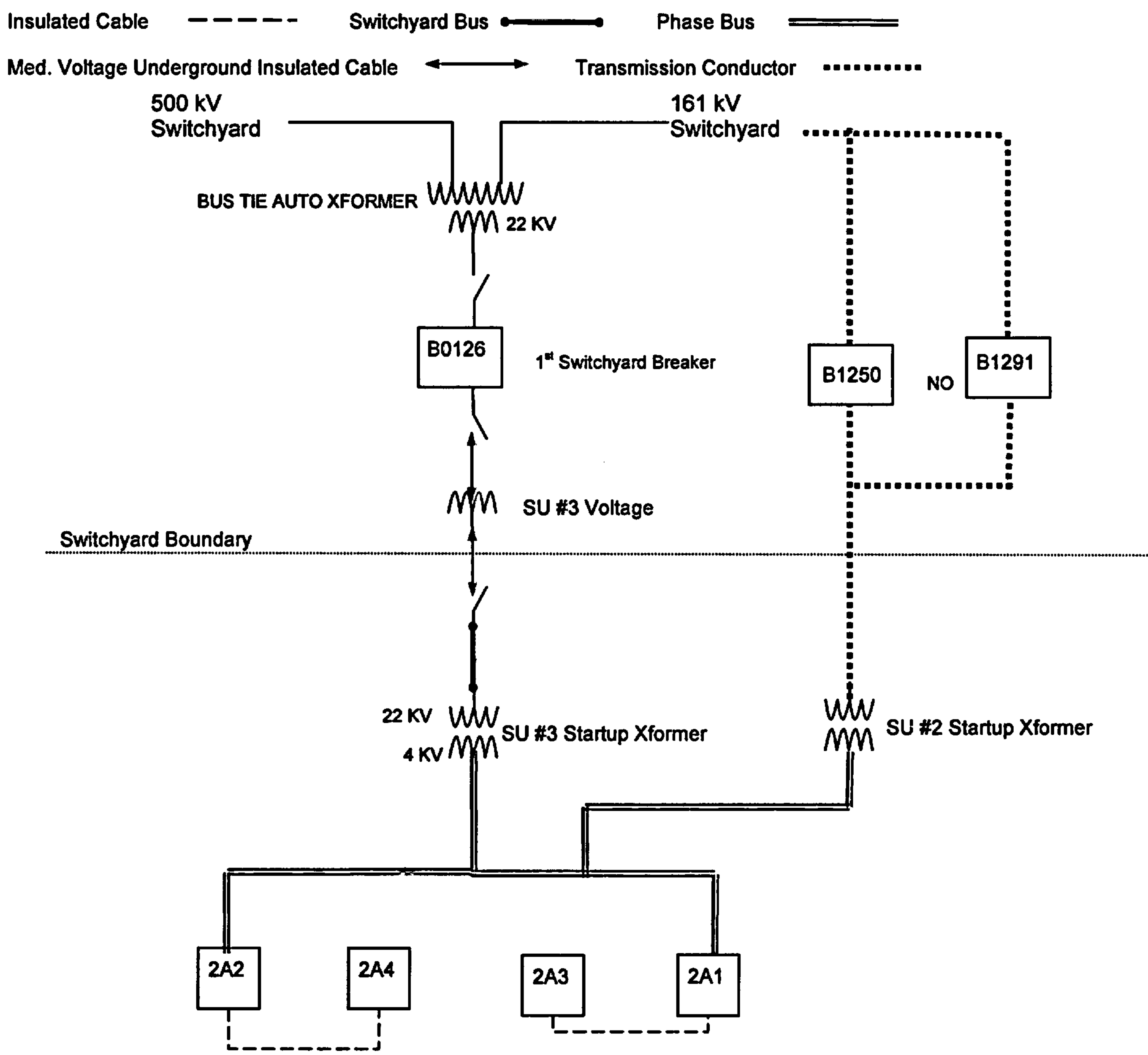
The 161kV portion of the switchyard is a 4-element ring bus. The four elements connected to this 161kV ring bus include the ANO-Russellville East 161kV transmission line, the ANO-Pleasant Hill 161kV transmission line, the ANO 500/161kV autotransformer, and the 161kV line which feeds an automatic voltage regulator in the switchyard which then feeds Startup Transformer #2. The ring bus is arranged so the autotransformer and the lines to Startup Transformer #2 are not connected to a common 161kV breaker. Likewise the two 161kV transmission lines are not connected to a common 161kV breaker.

The 161kV yard is separated from the autotransformer by two 161 kV circuit breakers. Therefore, the failure of any one of the 161kV breakers will trip the adjacent breakers and interrupt only one of the plant off-site power sources. The 500 kV lines and the autotransformer will remain available. Conversely, the failure of a 500 kV breaker which feeds the autotransformer will trip the two 161 kV breakers connected to the autotransformer, but will not interrupt the 161kV circuit to the plant.

SAR Section 8.2.1.2.G describes the overhead 161kV transmission conductors from 161kV switchyard breakers B1291 and B1250 to Startup Transformer #2. The high-voltage insulators associated with the transmission conductors are similar to the high-voltage insulators for the switchyard bus, which are already addressed in LRA Section 3.6.

The added 161kV switchyard circuit breakers B1291 and B1250, the overhead transmission conductors, and Startup Transformer #2 are shown on the sketch below.

SBO Offsite Power Recovery Diagram



The inclusion of Startup Transformer #2 and the associated overhead transmission conductors requires modification to the previous response for RAI 2.5-1(c), provided in a letter dated June 21, 2004 (2CAN060404). The revised response is as follows.

<u>RAI 2.5-1(c) Restated</u>: Section 2.1, Table 2.1-1 of the LRA indicates that transmission conductors are within the scope of license renewal. However, per Table 3.6.2-1, no aging effect and no aging management program is identified for these components. Please provide a detailed description as to why an aging management review is not required.

<u>Revised Response</u>: Based on the inclusion of Startup Transformer #2, transmission conductors, strain and suspension insulators, and insulated cables are subject to aging management review. Insulated cables were included in the ANO-2 LRA.

The transmission conductor component type includes transmission conductors and the hardware used to secure the conductors to the insulators. The materials for aluminum cable-steel reinforced (ACSR) transmission conductors are aluminum and steel, and the environment is outdoor weather. Based on industry guidance, potential aging effects and aging mechanisms are loss of conductor strength due to general corrosion (atmospheric oxidation of metals) and loss of material due to wear from wind loading.

Corrosion in ACSR conductors is a very slow acting mechanism. Corrosion rates are dependent on air quality. ANO is located in a mostly agricultural area with no significant nearby industries that could contribute to corrosive air quality. Corrosion testing of transmission conductors at Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor. The Institute of Electrical and Electronic Engineers National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. Therefore, assuming a 30% loss of strength, there would still be significant margin between what is required by the NESC and the actual conductor strength. In determining actual conductor tension, the NESC considers various loads imposed by ice, wind, and temperature as well as length of conductor span. The transmission conductors in scope for license renewal are short spans located within the high voltage switchyard. The maximum span for ANO conductors subject to aging management review is approximately 240 feet in length providing significant margin to maximum design loading limits. ANO is in the medium loading zone; therefore, the Ontario Hydroelectric heavy loading zone study is conservative with respect to loads imposed by weather conditions.

The Ontario Hydroelectric test envelops the conductors at ANO, demonstrating that the material loss on the ANO ACSR transmission conductors is acceptable for the period of extended operation. This illustrates with reasonable assurance that transmission conductors at ANO will have ample strength to perform their intended function throughout the renewal term; therefore, loss of conductor strength due to corrosion of the transmission conductors is not an aging effect requiring management.

Loss of material due to mechanical wear can be an aging effect for strain and suspension insulators that are subject to movement. Experience has shown that transmission conductors do not normally swing and that when they do swing because of substantial wind, they do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspection. Therefore, loss of material due to wear is not an aging effect requiring management for switchyard insulators.

Entergy reviewed industry operating experience and NRC generic communications related to the aging of transmission conductors in order to ensure that no additional aging effects exist beyond those identified above. Entergy also reviewed ANO plant-specific operating experience, including nonconformance reports, licensee event reports, and condition reports, and documented interviews with transmission engineering personnel. Entergy's review did not identify unique aging effects for transmission conductors beyond those identified above.

This conclusion that no aging management program is required for transmission conductor aging effects of loss of conductor strength and loss of material (mechanical wear) was reached by numerous previous applicants (Oconee, Turkey Point, North Anna and Surry, Peach Bottom, St. Lucie, Fort Calhoun, McGuire and Catawba, and Virgil C. Summer). This position was accepted by the Staff as documented in SERs for the associated license renewal applications.

RAI 3.2-11 Clarification: The Staff requests that the applicant confirm that planned activities will provide an appropriate sample for each material and environment combination, or to provide for a review to confirm that each one has been adequately sampled prior to the period of extended operation.

Response: The following engineered safety features (ESF) systems material and environment groups credit water chemistry control programs:

1. Carbon steel exposed to treated water >270°F:

   This group includes piping and valves in the steam generator secondary side sampling and blowdown lines. The Primary and Secondary Water Chemistry Control Program manages loss of material for these components.

   As noted in LRA Table 3.2.2-4, the Flow-Accelerated Corrosion (FAC) Program also manages loss of material for components in the blowdown lines. Recent examinations of these lines did not identify evidence of loss of material, confirming effectiveness of the water chemistry control program in managing loss of material for these components.

   Steam generator secondary side sampling lines are used <2% of the total plant operating time. Therefore, they are not susceptible to flow-accelerated corrosion. They may, however, experience loss of material due to general corrosion, pitting corrosion, crevice corrosion, microbiologically influenced corrosion or galvanic corrosion. Since the blowdown lines are exposed to the same harsh environment more frequently, the condition of the blowdown lines is representative of the condition of the steam generator secondary side sampling lines.

Additional components with this same material and environment are described in LRA Section 3.1, Reactor Vessel, Internals and Reactor Coolant System, and Section 3.4, Steam and Power Conversion Systems. Reactor coolant and steam and power conversion system components with this material and environment are nondestructively examined under the ISI, Steam Generator Integrity, FAC and Periodic Surveillance and Preventive Maintenance (PSPM) Programs, as well as during maintenance and chemistry inspections. These examinations provide further evidence that the Primary and Secondary Water Chemistry Control Program manages loss of material for carbon steel components exposed to treated water >270°F.

Therefore, the effectiveness of the Primary and Secondary Water Chemistry Control Program to manage loss of material for carbon steel components exposed to treated water >270°F has been confirmed.

2. Carbon steel exposed to treated water:

   This group includes piping and valves in lines supplying (and returning) chilled water, plant heating water and component cooling water to components inside containment. This group comprises thirty valves and associated piping. The Closed Cooling Water Chemistry Control Program manages loss of material for components in the component cooling water system and the Auxiliary Systems Water Chemistry Control Program manages loss of material for components in the chilled water and plant heating systems.

   Nine valves in this group were visually inspected during maintenance activities in the past three years. Two of the inspected valves are in the chilled water system and seven are in the component cooling water system. During these inspections, evidence of loss of material was not observed. Since all components in the group are exposed to the same environment, the condition of the inspected valves is representative of the condition of the other valves and associated piping.

   Additional components with this same material and environment are described in LRA Section 3.3, Auxiliary Systems. Visual inspections of auxiliary system components with this material and environment under the PSPM Program as well as during maintenance and chemistry inspections provide further evidence that the water chemistry control programs manage loss of material for carbon steel components exposed to treated water.

   Therefore, the effectiveness of the Closed Cooling and Auxiliary Systems Water Chemistry Control Programs to manage loss of material for carbon steel components exposed to treated water has been confirmed.

3. Inconel exposed to treated borated water:

   This group includes the safety injection tank nozzles. The Primary and Secondary Water Chemistry Control Program manages loss of material for these components.

Additional components with this material and environment are described in LRA Section 3.1, Reactor Vessel, Internals and Reactor Coolant System. Under the ISI and Reactor Vessel Head Penetration Programs, a number of Alloy-600, Alloy-52/152 and Alloy-82/182 locations receive examination in accordance with ASME Section XI. Items receiving volumetric, surface, or visual examination are listed below.

Pressurizer surge and spray nozzle-to-safe end dissimilar metal welds receive volumetric examination in accordance with ASME Section XI, Examination Category B-F. The measurement, vent, upper level, and temperature nozzles, and heater sheath, heater sleeve, and end plug received visual examination (VT-2) from the exterior of the vessel in accordance with ASME Section XI, Examination Category B-P.

Reactor coolant system surge, letdown, drain, charging inlet, safety injection, shutdown cooling, and spray nozzles-to-safe end dissimilar metal welds receive volumetric examination in accordance with ASME Section XI, Examination Category B-F. The resistance temperature device nozzles, pressure measurement nozzle, sampling nozzle, and replacement pressure nozzle receive either a surface (<4" NPS) or a surface and volumetric examination (≥4" NPS) under Examination Category B-J.

The control element drive mechanism (CEDM) motor housing upper and lower end fitting, and CEDM upper pressure housing lower fitting receive visual examination (VT-2) from the exterior in accordance with ASME Section XI, Examination Category B-P.

The surveillance capsule holder receives a visual examination (VT-1) in accordance with ASME Section XI, Examination Category B-N-2. In addition, the flow skirt, core stabilizing and stop lugs receive a visual examination (VT-3) in accordance with B-N-2.

The pressurizer heater and small bore penetrations are visually inspected.

Recent examinations and inspections of these components have not shown evidence of loss of material. In addition to treated borated water, the inspected components are exposed to reactor coolant system temperatures, while the safety injection tank nozzles are not. Since the inspected components are exposed to a harsher environment, the condition of the inspected components is representative of the condition of the safety injection tank nozzles.

Therefore, the effectiveness of the Primary and Secondary Water Chemistry Control Program to manage loss of material for inconel components exposed to treated borated water has been confirmed.

4. Stainless steel exposed to treated borated water >270°F:

This group includes low pressure safety injection (LPSI) pump seal cooler tubes; shutdown cooling heat exchanger tubes; LPSI pump casings; and orifices, piping, thermowells, tubing, and valves in the safety injection and containment spray systems. It also includes two solenoid valves in the steam generator secondary side sampling lines.

The Primary and Secondary Water Chemistry Control Program manages fouling for the LPSI pump seal coolers. LRA Table 3.2.2-1 indicates that fouling of the LPSI pump seal cooler tubes is also managed by the PSPM Program. This aging management program confirms that the Primary and Secondary Water Chemistry Control Program is effective in managing fouling.

The Primary and Secondary Water Chemistry Control Program manages the aging effects of fouling, cracking and loss of material for the shutdown cooling heat exchangers. LRA Table 3.2.2-2 indicates that fouling of the shutdown cooling heat exchanger tubes is also managed by the Service Water Integrity Program and cracking and loss of material are also managed by the Heat Exchanger Monitoring Program. These aging management programs confirm that the Primary and Secondary Water Chemistry Control Program is effective in managing fouling, cracking and loss of material of the shutdown cooling heat exchanger tubes.

The Primary and Secondary Water Chemistry Control Program manages cracking and loss of material for LPSI pump seal cooler tubes; LPSI pump casings; and orifices, piping, thermowells, tubing, and valves in the safety injection and containment spray systems. It also manages cracking and loss of material for the solenoid valves in the steam generator secondary side sampling lines.

Components in the group were visually inspected during maintenance. LPSI pump 2P-60A was inspected in 2002 and LPSI pump 2P-60B was inspected in 1999 and 2000. LPSI piping and orifices were inspected in 1994 and 1999. Containment spray piping and orifices were inspected in 1994, 1997, and 2000. During these inspections, evidence of aging effects was not observed. Since all components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

Additional components with this same material and environment are described in LRA Section Section 3.1, Reactor Vessel, Internals and Reactor Coolant System, and Section 3.4, Steam and Power Conversion Systems. Reactor coolant and steam and power conversion system components with this material and environment are visually and nondestructively examined under the ISI, Steam Generator Integrity, and PSPM Programs, as well as during maintenance and chemistry inspections. These examinations provide further evidence that the Primary and Secondary Water Chemistry Control Program manages loss of material for stainless steel components exposed to treated borated water >270°F.

Therefore, the effectiveness of the Primary and Secondary Water Chemistry Control Program to manage cracking and loss of material for stainless steel components exposed to treated borated water >270°F has been confirmed.

5. Stainless steel exposed to treated borated water:

   This group includes high pressure safety injection (HPSI) pump seal coolers; containment spray (CS) pump seal coolers; HPSI pump casings; CS pump casings; safety injection tanks; refueling water tank and heater housings; CS nozzles; and filter housings, orifices, piping thermowells, tubing and valves in the safety injection and CS systems. The Primary and Secondary Water Chemistry Control Program manages cracking and loss of material for these components.

   The Primary and Secondary Water Chemistry Control Program manages fouling for the HPSI and CS pump seal coolers. LRA Tables 3.2.2-1 and 3.2.2-2 indicate that fouling is also managed by the PSPM Program. This aging management program confirms that the Primary and Secondary Water Chemistry Control Program is effective in managing fouling.

   Components in the group were visually inspected during maintenance. A HPSI pump was inspected in 2000 and another was inspected in 2003. A CS pump was inspected in 2003. HPSI piping and an orifice were inspected in 2000. CS piping was inspected in 2002. Internals of the refueling water tank were inspected in 1999. During these inspections, evidence of aging effects was not observed. Since all components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

   Additional components with this same material and a harsher environment (treated borated water >270°F) are described LRA Section LRA Section 3.1, Reactor Vessel, Internals and Reactor Coolant System, and in LRA Section 3.4, Steam and Power Conversion Systems. These components were discussed previously in item 4. Inspections of components with this material and environment under the ISI, Steam Generator Integrity, and PSPM Programs and during maintenance and chemistry inspections provide further evidence that the Primary and Secondary Water Chemistry Control Program manages cracking and loss of material for stainless steel components exposed to treated borated water.

   Therefore, the effectiveness of the Primary and Secondary Water Chemistry Control Program to manage cracking and loss of material for stainless steel components exposed to treated borated water has been confirmed.

<u>RAI 3.3-1 Clarification</u>: This item concerns the use of a condition monitoring program to manage fatigue cracking in the chemical volume control system (CVCS) charging pumps rather than a TLAA used for other CVCS components. The applicant's response to RAI 3.3-1 clarifies that the type of fatigue is high-cycle fatigue (rather than thermal) and a requirement for a TLAA does not exist. The applicant states that the preventative maintenance has been effective in identifying aging effects prior to loss of system function. The 1989 ASME Section III Code NC-3454.4 states that, for reciprocating pumps, the liquid cylinder and bolting are exposed to significant fatigue loadings, but a specific fatigue analysis is not required. Since a requirement for a TLAA does not exist, the use of the PSPM Program appears to be appropriate to detect and correct cracking. However, the PSPM aging management program B.1.18 and aging management review Table 3.3.2-5 do not address fatigue-cracking in the charging pump bolting and the PSPM does not address fatigue-cracking in the casing. The applicant is requested to clarify how the PSPM or other aging management programs manage fatigue-cracking in the charging pump casing and bolting.

<u>Response</u>: Fatigue-cracking of the charging pump block (casing) occurred in the early 1990's at ANO-2. As a result of this cracking, the pump block design was modified to incorporate features that increase resistance to fatigue cracking such as enlarged radii at the bore intersection and shotpeening. Since the design change was implemented, there have been no instances of charging pump block cracking which provides evidence that the condition has been corrected.

Cracking of charging pump bolting was not identified in the operating experience review and as such was not identified as an aging effect requiring management.

Based on operating experience, cracking due to fatigue was not identified in the LRA as an aging effect requiring management for the charging pump block or bolting.

<u>RAI 3.3-2 Clarification</u>: This item concerns the application of water chemistry control subprograms to specific systems. The applicant's response does not address the following concern:

The response identifies that effectiveness of the water chemistry programs has been confirmed through routine component inspections, including the auxiliary systems water chemistry programs. The response also states that a combination of the ISI Program, Steam Generator Integrity Program, and maintenance and routine chemistry inspections, as a whole, constitute a more thorough confirmation of the chemistry aging management program effectiveness than could be obtained from the one-time inspections of a sample of items. The Staff questions the applicability of the Steam Generator Integrity Program to auxiliary systems and the ISI Program inspections for auxiliary systems may be limited to external surface inspections. It is not clear if the internal chemistry inspections include auxiliary system components or if these inspections are representative of auxiliary system chemistry. Where only opportunistic inspections are used to manage internal surfaces of auxiliary systems containing treated water, it is not clear how these inspections represent an adequate sample size or will be completed prior to the period of extended operation. The applicant is requested to clarify whether auxiliary system inspections are limited to opportunistic inspections and explain how the ANO-2 chemistry program verification inspections provide an appropriate sample size required by the Generic Aging Lessons

Learned (GALL) one-time inspection program. The applicant is also requested to clarify how the chemistry verification inspections will be completed prior to the period of extended operation. Alternatively, the LRA may identify the application of planned maintenance inspections for auxiliary systems such as the PSPM Program or the use of future one-time inspections consistent with GALL.

Response: While many auxiliary system inspections are opportunistic inspections during maintenance, some are performed periodically, as discussed below.

The following auxiliary system material and environment groups credit water chemistry control programs.

1. Carbon steel exposed to treated water:

   This group includes emergency diesel generator (EDG) turbochargers, standby coolant heater housings, coolant orifices, piping, coolant pump casings, coolant expansion tanks, tubing, and coolant valve bodies. It includes the radiator, jacket water heater housing, piping, coolant pumps, coolant expansion tank, tubing and valve bodies associated with the alternate alternating current (AC) diesel generator. As described in the 10CFR54.4(a)(2) report, the group also includes the letdown heat exchanger shell and nonsafety-related carbon steel components exposed to treated water in the auxiliary building heating and ventilation, chilled water, component cooling water, domestic water, main feedwater, plant heating, sampling, auxiliary steam, blowdown, emergency feedwater (EFW), main steam, primary sampling and steam generator secondary systems. The Closed Cooling Water Chemistry Control Program manages loss of material for components in the diesel generator, alternate AC diesel and component cooling water systems. The Primary and Secondary Water Chemistry Control Program manages loss of material for components in the main feedwater, blowdown, EFW, main steam, primary sampling and steam generator secondary systems. The Auxiliary Systems Water Chemistry Control Program manages loss of material for components in the auxiliary building heating and ventilation, chilled water, domestic water, plant heating, sampling, and auxiliary steam systems.

   Several components in the group were visually inspected during maintenance. The four EDG turbochargers were disassembled and inspected in 1999, an EDG standby coolant circulation pump was inspected in 2004, both EDG jacket water pumps were inspected in 2004, and the air cooler coolant pumps were inspected in 1994 and 2002. All of these components are exposed to stagnant conditions when the EDGs are in standby. Also, the letdown heat exchanger shell was examined in 1997 and 2000. During these inspections, evidence of loss of material was not observed. Since components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

   Additional components with this same material and environment are described in LRA Section 3.1, Reactor Vessel, Internals and Reactor Coolant System; Section 3.2, Engineered Safety Features (ESF); and Section 3.4, Steam and

Power Conversion Systems. Inspections of components with this material and environment under the ISI, Steam Generator Integrity, and PSPM Programs and during maintenance and chemistry inspections provide further evidence that the water chemistry control programs manage loss of material for carbon steel components exposed to treated water.

Therefore, the effectiveness of the water chemistry control programs to manage loss of material for carbon steel components exposed to treated water has been confirmed.

2. Cast iron exposed to treated water:

   This group includes emergency diesel generator temperature regulating valve bodies, alternate AC diesel generator temperature regulating valve bodies, and the alternate AC diesel generator jacket water heater pump casing. The Closed Cooling Water Chemistry Control Program manages loss of material for these components.

   LRA Tables 3.3.2-3 and 3.3.2-4 indicate that loss of material for the temperature regulating valve bodies is also managed by the PSPM Program. This program confirms that the Closed Cooling Water Chemistry Control Programs is effectively managing loss of material for these components. The PSPM Program has not identified evidence of loss of material on the valve bodies.

   Since they are exposed to the same environment and the pump is newer (replaced in 2002 due to design problems), the condition of the temperature regulating valve bodies is representative of the condition of the alternate AC diesel generator jacket water heater pump casing.

   Therefore, the effectiveness of the Closed Cooling Water Chemistry Control Program to manage loss of material for cast iron components exposed to treated water has been confirmed.

3. Copper alloy exposed to treated water:

   This group includes the EDG air coolers, jacket water heat exchangers, air coolant heat exchangers, associated tubing and valves. It includes the alternate AC diesel generator after-cooler heat exchanger and components in the engine cooling water sub-system. As described in the 10CFR54.4(a)(2) report, the group also includes the nonsafety-related copper alloy components exposed to treated water in the auxiliary building heating and ventilation, chilled water, component cooling water, condensate storage and transfer, domestic water, and plant heating systems. The Closed Cooling Water Chemistry Control Program manages loss of material for components in the diesel generator, alternate AC diesel and component cooling water systems. The Auxiliary Systems Water Chemistry Control Program manages loss of material for components in the auxiliary building heating and ventilation, chilled water, condensate storage and transfer, domestic water, and plant heating systems.

The water chemistry control programs manage fouling for the EDG jacket water cooler and air coolant heat exchanger tubes. LRA Table 3.3.2-3 indicates that fouling of these heat exchangers is also managed by the Service Water Integrity Program. This aging management program confirms the effectiveness of the water chemistry control programs in managing fouling.

The water chemistry control programs manage fouling for the EDG air cooler tubes. LRA Table 3.3.2-3 indicates that fouling of these heat exchangers is also managed by the PSPM Program. This aging management program confirms the effectiveness of the water chemistry control programs in managing fouling.

Several components in the group were visually inspected during maintenance. For example, the jacket water and air coolant heat exchangers on the "A" EDG were disassembled and inspected in 1991. Also, the EDG air coolers have been disassembled and inspected – the most recent one in 2000. These components are exposed to stagnant conditions when the EDGs are in standby. During these inspections, evidence of loss of material was not observed. Since components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

Therefore, the effectiveness of the Closed Cooling and Auxiliary Systems Water Chemistry Control Program to manage loss of material for copper alloy components exposed to treated water has been confirmed.

4. Stainless steel exposed to treated borated water:

   This group includes the spent fuel racks, the fuel transfer tube, piping and valves in the spent fuel system. It also includes charging and boric acid makeup pumps casings, boric acid makeup tanks, pulsation dampeners, piping, thermowells, tubing and valves in the CVCS. As described in the 10CFR54.4(a)(2) report, the group also includes the nonsafety-related stainless steel components exposed to treated borated water in the boron management, containment spray, chemical and volume control, low pressure safety injection, post accident sampling, primary sampling, reactor coolant pump, reactor coolant, and shutdown cooling systems. The Primary and Secondary Water Chemistry Control Program manages the aging effects of cracking and loss of material for these components.

   The charging pumps and their suction and discharge pulsation dampeners are inspected under the PSPM Program. Other components in the group were visually inspected during maintenance. For example, the boric acid makeup pumps were inspected, one in 1999, the other in 2000. The fuel transfer tube isolation valve was inspected in 1996 and 2002. During these inspections no evidence of cracking or loss of material attributable to poor water quality was observed. Since all components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

Additional components with this same material and environment are described in LRA Section 3.1, Reactor Vessel, Internals and Reactor Coolant System, and Section 3.2, Engineered Safety Features (ESF). Inspections of components with this material and environment under the ISI, Steam Generator Integrity, and PSPM Programs and during maintenance and chemistry inspections provide further evidence that the Primary and Secondary Water Chemistry Control Program manages cracking and loss of material for stainless steel components exposed to treated borated water.

Therefore, the effectiveness of the Primary and Secondary Water Chemistry Control Program to manage cracking and loss of material for stainless steel components exposed to treated borated water has been confirmed.

5. Stainless steel exposed to treated water:

This group includes EDG cooling water piping, thermowells, tubing and valves; alternate AC diesel generator cooling water expansion joints, orifices, thermowells, tubing and valves; and piping, tubing and valves in the containment demineralized and makeup water supply lines. As described in the 10CFR54.4(a)(2) report, the group also includes nonsafety-related stainless steel components exposed to treated water in the chilled water, auxiliary steam, blowdown, component cooling water, condensate storage and transfer, EFW, fuel pool cooling, main steam, plant heating, primary sampling, reactor coolant, and sampling systems. The Closed Cooling Water Chemistry Control Program manages loss of material for components in the diesel generator, alternate AC diesel and component cooling water systems. The Primary and Secondary Water Chemistry Control Program manages loss of material for components in the blowdown, emergency feedwater, fuel pool cooling, main steam, primary sampling, and reactor coolant systems. The Auxiliary Systems Water Chemistry Control Program manages loss of material for components in the chilled water, auxiliary steam, condensate storage and transfer, plant heating, and sampling systems.

Components in this group were visually inspected during maintenance. A containment demineralized water supply valve and an EDG expansion tank fill valve were disassembled and inspected in 1999. Also, two EDG expansion tank drain valves were disassembled and inspected in 2004. These components are exposed to stagnant conditions when the EDGs are in standby. During these inspections, evidence of loss of material was not observed. Since components in the group are exposed to the same environment, the condition of the inspected components is representative of the condition of the other components.

Additional components with this same material and environment are described in LRA Section 3.4, Steam and Power Conversion Systems. Inspections of steam and power conversion system components with this material and environment under the Flow-Accelerated Corrosion and PSPM Programs and during maintenance and chemistry inspections provide further evidence that the water chemistry control programs manage cracking and loss of material for stainless steel components exposed to treated water.

Therefore, the effectiveness of the water chemistry control programs to manage loss of material for stainless steel components exposed to treated water has been confirmed.

6. Aluminum exposed to treated water:

   As described in the 10CFR54.4(a)(2) report, this group includes one nonsafety-related valve body in the component cooling water system which was installed in 1998. The Closed Cooling Water Chemistry Control Program manages loss of material for this component.

   The component has not been inspected to verify effectiveness of the Closed Cooling Water Chemistry Control Program to manage loss of material for the aluminum component exposed to treated water. However, as indicated in item 1, the effectiveness of the Closed Cooling Water Chemistry Control Program to manage loss of material for carbon steel components exposed to treated water has been confirmed. Since aluminum has better corrosion resistance than carbon steel, it is reasonable to assume that the Closed Cooling Water Chemistry Control Program would also be effective in managing loss of material for the aluminum component exposed to treated water.

Inspections that verify the effectiveness of the water chemistry control programs have already been completed. These inspections have confirmed the effectiveness of water chemistry control programs in managing the effects of aging on auxiliary system components.

<u>RAI 3.3-3 Clarification</u>: This item is concerned with the inspection criteria, frequency and technical basis for inspection of flex hoses to be managed by the PSPM Program. The applicant's response to RAI 3.3-3 indicates that the details of the inspection criteria and frequency will be determined prior to the period of extended operation. The inspection criteria and basis is not identified in the aging management program and is required to determine if the program effectively manages the aging effects. The applicant is requested to identify criteria for inspection of flexible hoses managed by the PSPM Program and identify a commitment to have plant procedures updated prior to the period of extended operation.

<u>Response:</u> As stated in the response to RAI 3.3-3, the PSPM Program will manage the effects of aging on flexible hoses through visual examination of external and internal surfaces. This visual examination looks for evidence of cracking and changes in material properties such as loss of flexibility and embrittlement. The flexibility of the hoses will be verified through physical manipulation of the hose concurrent with the visual inspection. If evidence of degradation is detected, the hoses will be replaced. These hoses will be inspected at least once every 10 years. The hoses that credit the PSPM Program are in the emergency diesel generator, fuel oil, alternate AC, and nitrogen systems. Procedures and preventive maintenance tasks for the inspection of flex hoses in these systems using the

above criteria will be implemented prior to the period of extended operation. Alternatively, periodic replacement of the hose may be implemented in lieu of periodic inspection.

RAI 3.3.2.4.11-1 Clarification: This item is concerned with managing internal aging effects for 10CFR54.4(a)(2) components by performing external inspections using the System Walkdown Program. The applicant response to RAI 3.3.2.4.11-1 credits a combination of five aging management programs for managing aging effects for 10CFR54.4(a)(2) systems. The response clarifies that one of these programs, the System Walkdown Program, manages effects by detecting leakage through visual inspections and concludes that the operating experience and routine operator rounds/system walkdowns, in conjunction with other programs, provide reasonable assurance that leaks from nonsafety-related systems, structures, and components (SSCs) will not preclude the satisfactory accomplishment of required safety functions. The Staff requires that, for all components within license renewal scope, aging management programs are required to prevent fluid leaks rather than only detect and mitigate the consequences of the leak. NRC letter to the Nuclear Energy Institute dated March 15, 2002, clarified that the applicant has two options when performing its scoping evaluation for nonsafety-related SSCs. If the applicant cannot demonstrate that the mitigative features (e.g., spray and drip shields, seismic supports, flood barriers, etc.) are adequate to protect safety related SSCs from the consequences of failures of nonsafety-related SCCs, then the applicant should use the preventive option by including the nonsafety-related SCCs within scope. Since the ANO-2 nonsafety-related SSCs are within scope, the preventive action is applicable with appropriate preventive rather than mitigative aging management programs. Leak detection is considered to be a mitigative program and internal inspections are considered to be a preventive program. This concern was explained to the applicant in a phone call on June 22, 2004, and the applicant agreed to supply additional information regarding aging management of system components that rely only on the plant walkdown program. On July 2, 2004, the applicant provided additional information to support the aging management of 10CFR54.4(a)(2) components. This response identifies that, for the nine pressurized systems containing raw or untreated water, operating experience and maintenance inspections did not identify any abnormal corrosion in 25 years of operation.

The Staff is concerned that the use of external visual inspections alone is not appropriate to manage internal aging effects. The applicant does not have a future one-time inspection program and LRA Table 3.3.2-11 does not include a preventive program for managing internal aging effects for the 10CFR54.4(a)(2) components containing raw or untreated water. The applicant should clarify that a preventive program such as the PSPM will continue to assure that internal maintenance inspections will detect and correct abnormal aging effects in these systems prior to loss of pressure boundary to satisfy the 10CFR54.4(a)(2) criteria.

Response: As documented in ANO-2 Safety Analysis Report (SAR) Section 3.6, measures have been taken in the design and construction of ANO-2 to protect structures, systems and components required to place the reactor in a safe cold shutdown condition from the dynamic effects associated with the postulated rupture of piping. In accordance with NUREG-0800, Section 3.6.1, protection of safety-related SSCs against piping failures is not required if those safety-related SSCs are not required to mitigate consequences of the piping failure and achieve safe shutdown. SAR Section 3.6 documents the evaluation of postulated breaks in non-Seismic Category 1 piping systems. Criteria employed in the evaluation include the requirement that single failures of non-Class I system components or pipes shall not result in loss of a system important to safety. Redundant safety equipment shall be separated and protected to assure operability in the event a non-Class 1 system or component fails.

Results of the evaluations documented in SAR Section 3.6.4 are that equipment arrangement and design features provide the necessary protection of systems and components required to shut down the reactor and mitigate the consequences of postulated piping failures. In these evaluations, failures are postulated in nonsafety-related systems. Regulatory acceptance criteria allow failures that do not result in loss of a system important to safety. This is the current licensing basis (CLB) for ANO-2. Per the statement of considerations for the license renewal rule, the plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term. The management of aging effects on 10CFR54.4(a)(2) SSCs by the System Walkdown Program during the renewal term is consistent with the plant-specific licensing basis during the original license term. Requiring an aging management program to prevent leakage from nonsafety-related systems goes beyond requirements of the CLB.

Notwithstanding the above, Entergy conservatively identified 36 systems that contain nonsafety-related components as in scope for 10CFR54.4(a)(2) as shown in Table 1. Twenty-three of these systems contain treated water. For the treated water systems, water chemistry control is credited with managing the aging effects in addition to system walkdowns. The ANO-2 water chemistry programs' effectiveness has been verified as described in the response to RAIs 3.2-5, 3.4-3, and 3.4-6 in correspondence dated April 6, 2004 (2CAN040401), and RAI 3.3-2 in correspondence dated June 21, 2004 (2CAN060402).

The remaining 13 systems in scope for 10CFR54.4(a)(2) have at least a portion of the system that is exposed to raw or untreated water. The following discussion provides additional basis for acceptability of the System Walkdown Program as the sole aging management program for managing the effects of aging on systems that have components containing untreated or raw water.

1. The auxiliary cooling water (ACW) system is supplied from the service water system. The service water chemistry is controlled under the Service Water Integrity Program (SWIP) which, therefore, manages the effects of aging on 10CFR54.4(a)(2) components in the ACW system.

2. The 10CFR54.4(a)(2) portion of the fire protection water system is connected to the 10CFR54.4(a)(3) portion and contains the same environment. The Fire Protection Program that manages aging effects on 10CFR54.4(a)(3) components also manages the aging effects on 10CFR54.4(a)(2) components in the fire protection system.

3. The majority of the service water piping is safety-related and is included in the service water aging management review. The effects of aging on the 10CFR54.4(a)(1) components of the service water system are managed by the SWIP. The same aging management program manages the effects of aging on 10CFR54.4(a)(2) components in the system.

4. The circulating water system has a line that is used to drain the circulating water system to the service water discharge pipe. The drain line is not used during normal power operation, but a portion of it is pressurized by the service water system. The effects of aging on this line are managed by the SWIP, which applies to the service water system.

5. The portions of the turbine building sump system that are in safety-related areas are floor drains and associated piping that are not pressurized and therefore do not pose a significant hazard.

6. The remaining eight systems have carbon steel or stainless steel components which may be pressurized and contain raw or untreated water. This water in many of these systems is considered untreated water even though its source is a treated water system. These components will be adequately managed by the System Walkdown Program for the following reasons.

   - Many of the components are only pressurized for short durations such that they would not impact nearby safety-related equipment through spray or leakage.

   - There are components that are drains on tanks and other treated water systems that actually are exposed to treated water such that aging effects would be managed by the water chemistry control program for that system.

   - Stainless steel components are not susceptible to significant aging effects due to the inherent corrosion resistance of stainless steel. Corrosion that might occur would be localized and not result in significant leakage which could impact nearby safety-related equipment through spray or leakage.

   - The carbon steel components containing raw or untreated water could experience general corrosion, pitting and crevice corrosion and MIC that would result in pinhole leaks in the system long before overall wall thickness is significantly impacted. This localized corrosion would be detected by the System Walkdown Program and other routine inspections before significant leakage can impact safety-related equipment in the area. Operating experience has shown that localized pinhole leakage has not resulted in the failure of safety-related equipment nor has it prevented the accomplishment of a required safety function as stated in 10CFR54.4(a)(2).

Components in these systems are inspected during maintenance and modification activities. During these activities, abnormal corrosion or degradation would be noted in the work order, and in addition, a condition report would be initiated. A review of condition reports written against the systems included in item 6 over the past five years did not identify conditions that indicate abnormal corrosion in these systems after more than 25 years of operation.

In summary,

1. The original licensing basis identifies that protection of safety-related SSCs against piping failures is not required if those safety-related SSCs are not required to mitigate consequences of the piping failure and achieve safe shutdown.
2. Site and industry experience indicate the minimal hazards from these low-energy systems and that leakage would be from localized pitting or crevice corrosion and detected by walkdowns before impacting the capability to satisfactorily accomplish any of the functions of 10CFR54.4(a)(1).
3. Site-specific operating experience, including inspections performed during maintenance, has not identified abnormal corrosion or degradation in these systems.

Based on operating experience and CLB requirements, system walkdowns are adequate to manage the effects of aging on these remaining eight systems.

Table 1

SYSTEM CODE	SYSTEM NAME	Raw/Untreated Water	Treated Water
ABHV	Auxiliary Building Heating and Ventilation	X	X
ABS	Auxiliary Building Sump	X	
AC	Chilled Water		X
ACW	Auxiliary Cooling Water	X	
AS	Auxiliary Steam		X
BD	Startup and Blowdown Demineralizers		X
BMS	Boron Management		X
BS	Containment Spray		X
CA	Chemical Addition		X
CCW	Component Cooling Water		X
CT	Condensate Storage and Transfer		X
CVCS	Chemical and Volume Control		X
CW	Circulating Water	X	
DCH	Drain Collection Header	X	
DW	Domestic Water		X
EFW	Emergency Feedwater		X
FP	Fuel Pool Cooling and Purification		X
FS	Fire Protection (Water)	X	
FW	Feedwater		X

SYSTEM CODE	SYSTEM NAME	Raw/Untreated Water	Treated Water
LPSI	Low Pressure Safety Injection		X
LRW	Liquid Radwaste Management	X	X
MS	Main Steam		X
PASS	Post Accident Sampling System	X	X
PH	Plant Heating		X
PS	Primary Sampling		X
RBHV	Reactor Building Heating and Ventilation		X
RCP	Reactor Coolant Pump		X
RCS	Reactor Coolant System		X
RT	Resin Transfer	X	
RZ	Regenerative Waste	X	
SDC	Shutdown Cooling		X
SGS	Steam Generator Secondary/Blowdown		X
SS	Sampling System		X
SW	Service Water	X	
SZ	Spent Resin	X	
TBS	Turbine Building Sump	X	

Attachment 2

2CAN080401

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

COMMITMENT	TYPE (Check One)		SCHEDULED COMPLETION DATE (If Required)
	ONE-TIME ACTION	CONTINUING COMPLIANCE	
Wells are no longer available for sampling groundwater. Consequently, in lieu of sampling groundwater to confirm that it remains non-aggressive, concrete exposed to groundwater is included in the Structures Monitoring Program for inspection to confirm the absence of aging effects. Under the Structures Monitoring Program, concrete exposed to lake water is periodically inspected. Since lake water chemistry is representative of groundwater chemistry, results of these inspections will be representative of underground concrete exposed to groundwater. In addition, when excavated for maintenance activities, inaccessible concrete exposed to groundwater will be visually inspected under the Structures Monitoring Program. (Note: This commitment replaces a commitment to perform groundwater monitoring that was inadvertently left in 2CAN070409 correspondence dated July 22, 2004.)		X	July 17, 2018
The intake canal is periodically inspected as part of the ANO Maintenance Rule Program. Periodic inspections will continue into the period of extended operation.		X	July 17, 2018

Consistent with 10CFR54.21(c)(1)(iii), loss of tendon prestress will be adequately managed during the period of extended operation by continued implementation of tendon inspections required by the American Society of Mechanical Engineers (ASME) Code Section XI IWL. In accordance with NUREG 1800, Section 4.5.3.1.3, relevant operating experience, including experience with prestressing systems described in NRC Information Notice (IN) 99-10, will be considered during inspections and data analysis. Prior to the period of extended operation, trend lines for ANO-2 tendon prestressing forces will be developed using regression analysis in accordance with guidance provided in NRC IN 99-10. If future tendon examination data diverge from the expected trend, the discrepancy will be addressed in accordance with requirements of the Containment Inservice Inspection (ISI) Program (IWE/IWL) and the current licensing basis. In summary, the ANO-2 Containment ISI Program in accordance with the requirements of ASME Code Section XI IWL will provide reasonable assurance that the effects of aging on the intended functions of tendons will be adequately managed for the period of extended operation in accordance with the provisions of 10CFR54.21(c)(1)(iii).		X	July 17, 2018

The PSPM Program will manage the effects of aging on flexible hoses through visual examination of external and internal surfaces. This visual examination looks for evidence of cracking and changes in material properties such as loss of flexibility and embrittlement. The flexibility of the hoses will be verified through physical manipulation of the hose concurrent with the visual inspection. If evidence of degradation is detected, the hoses will be replaced. These hoses will be inspected at least once every 10 years. The hoses that credit the PSPM Program are in the emergency diesel generator, fuel oil, alternate AC, and nitrogen systems. Procedures and preventive maintenance tasks for the inspection of flex hoses in these systems using the above criteria will be implemented prior to the period of extended operation. Alternatively, periodic replacement of the hose may be implemented in lieu of periodic inspection..		X	July 17, 2018