Entergy

Entergy Operations, Inc.
1448 S.R. 333
Russellville, AR 72801
Tel 501-858-4888

C. Randy Hutchinson
Vice President
Operations ANO

January 31, 2000

1CAN010003

U. S. Nuclear Regulatory Commission
Document Control Desk
Mail Station OP1-17
Washington, DC 20555

Subject: Arkansas Nuclear One - Unit 1
Docket No. 50-313
License No. DPR-51
License Renewal Application

Gentlemen:

Pursuant to 10CFR Part 54, Entergy Operations hereby applies for the renewal of the operating license for Arkansas Nuclear One, Unit 1 (ANO-1) by which the license would be extended for an additional 20 years beyond the current expiration date. With renewal, the ANO-1 Operating License would be extended from midnight on May 20, 2014, until midnight on May 20, 2034.

The enclosed ANO-1 License Renewal Application (LRA) contains the information required by 10CFR Part 54 for the contents of an application including an environmental report, entitled "Applicant's Environmental Report – Operating License Renewal Stage," (ER) satisfying the applicable requirements of Subpart A of 10CFR Part 51. In addition, Entergy Operations has utilized the standard license renewal application format, as accepted by the NRC's letter dated August 9, 1999, to the Nuclear Energy Institute. This application is also submitted in accordance with Subpart A of 10CFR Part 2, 10CFR50.4, and 10CFR50.30.

As required by 10CFR54.21(b), current licensing basis changes, which have a material effect on the content of this application, will be identified at least annually while the application is under NRC review and at least three months prior to the scheduled completion of the NRC review. Also, a summary of Entergy Operations' commitments with respect to license renewal are provided in the attachment to this letter.

Pursuant to 10CFR54.17(a), 10CFR50.4(b), and 10CFR51.55(a) Entergy Operations hereby submits the original (plus 40 copies) of the ANO-1 LRA and supporting ER. Should you have any questions concerning this submittal, please contact my staff.

A087

Very truly yours,

CRH/nbm
Enclosure

To the best of my knowledge and belief, the statements contained in this submittal are true.

SUBSCRIBED AND SWORN TO before me, a Notary Public in and for Johnson **County and the State of Arkansas, this** 27 **day of** January**, 1999.**

Juana M. Tapp
Notary Public
My Commission Expires 11-8-2000

OFFICIAL SEAL
JUANA M. TAPP
NOTARY PUBLIC - ARKANSAS
JOHNSON COUNTY
My Commission Expires: 11 - 8 - 2000

cc: Mr. Ellis W. Merschoff
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

Mr. Sam Collins
Director of the Office of NRR
U. S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

NRC Senior Resident Inspector
Arkansas Nuclear One
P.O. Box 310
London, AR 72847

Mr. Chris Nolan
NRR Project Manager Region IV/ANO-1
U. S. Nuclear Regulatory Commission
NRR Mail Stop 04-D-03
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Mr. Steve Hoffman
U. S. Nuclear Regulatory Commission
NRR Mail Stop 0-12G15
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Mr. Tom Kenyon
U. S. Nuclear Regulatory Commission
NRR Mail Stop 0-11F1
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

ANO-1 LRA Commitments Summary

Commitment	LRA App. A Section	Type of Commitment	Scope
New Commitments			
Buried Pipe Inspection	16.1.1	New	New Site Activity – Involves performing visual inspection of buried piping whenever site excavation work uncovers service water or diesel fuel oil safety-related buried piping. Program will be implemented prior to May 20, 2014.
Electrical Component Inspection Program	16.1.2	New	New Site Activity – Involves visual examination of selected cables, splices, and connectors in several plant areas. These selected electrical components will be inspected at least once every 10 years. First inspection will be completed prior to May 20, 2014.
Heat Exchanger Monitoring Program	16.1.3	New	New Site Activity – Involves performing NDE of a sample of safety-related heat exchangers on a periodic basis. First inspection will be completed prior to May 20, 2014.
Pressurizer Examinations	16.1.4	New	See Below
Pressurizer Cladding Examination	16.1.4.1	New	New Commitment – However, credit is taken for existing ISI examination, no new inspection involved.
Pressurizer Heater Bundle Penetration Welds Examination	16.1.4.2	New	New Site Activity – When a pressurizer heater bundle is removed from Oconee or ANO-1, a surface/visual examination of the inaccessible weld will be performed on a one-time basis to determine if subsequent inspections are needed.
Reactor Vessel Internals Aging Management Program	16.1.5	New	New Site Activity – Involves a new inspection program beginning after May 20, 2014, and continuing through year 60. Inspections may include volumetric examination of a sample of baffle bolts and visual examination of the reactor vessel internals. Periodic updates and a report defining the inspection program will be provided to the NRC prior to May 20, 2014. Entergy Operations is also committing to participate in the BWOG RVIAMP and associated EPRI Materials Reliability Project ITG efforts on this subject. Entergy Operations is also committing to perform analyses of the internals to address adequate ductility concerns.
Spent Fuel Pool Monitoring Program	16.1.6	New	New Site Activity – Quarterly checks of the spent fuel pool trench drains to identify any leakage. First inspection to begin prior to May 20, 2014.
Wall Thinning Inspection	16.1.7	New	New Site Activity – Periodic NDE examination of a sample of safety-related carbon steel components in the EFW system, NaOH tank, main steam system, and reactor building penetrations. First inspection will be completed prior to May 20, 2014.

ANO-1 LRA Commitments Summary

Commitment	LRA App. A Section	Type of Commitment	Scope
Existing (and Modified Existing) Programs – License Renewal Commitments			
Alloy 600 Aging Management Program	16.2.1	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
Alternate AC Diesel Generator Testing and Inspection	16.2.2	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
ASME Section XI Inservice Inspection Program	16.2.3	Existing	See Below
IWB Inspections	16.2.3.1	Modified	LR Commitment – Credit is taken for existing inspections. New Site Activity – In addition to the existing commitments to IWB, a reactor coolant pump casing will be inspected prior to May 20, 2014.
IWC Inspections	16.2.3.2	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
IWD Inspections	16.2.3.3	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
IWE Inspections	16.2.3.4	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
IWF Inspections	16.2.3.5	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
IWL Inspections	16.2.3.6	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
Augmented Inservice Inspections	16.2.3.7	Modified	See Below
Inspections of non-Class 2 MFW and main steam system welds for HELB	16.2.3.7	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
inspection of BWST header	16.2.3.7	Existing	LR Commitment – Credit is taken for existing inspections, no new inspection involved.
Inspections of penetrations 10, 47, 58, 64	16.2.3.7	Modified	New Site Activity -- NDE of a sample of the components identified within the scope of license renewal. First inspection to begin prior to May 20, 2014.
Inspection of penetration 68 piping & components and inspection of DH pump room drain valves	16.2.3.7	Modified	New Site Activity – NDE of a sample of the components identified within the scope of license renewal. First inspection to begin prior to May 20, 2014.
Special inspection of RB sump components wetted by sump water	16.2.3.7	Modified	New Site Activity -- NDE of a sample of the components identified within the scope of license renewal. First inspection to begin prior to May 20, 2014.
Special inspection of Q stainless steel piping	16.2.3.7	Modified	New Site Activity – NDE of a sample of the piping identified within the scope of license renewal. First inspection to begin prior to May 20, 2014.
Small Bore Piping and Small Bore Nozzles Inspections	16.2.3.8	Existing	LR Commitment – Credit is taken for existing ISI examination, no new inspection involved.
Bolting and Torquing Activities	16.2.4	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Boric Acid Corrosion Prevention Program	16.2.5	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.

ANO-1 LRA Commitments Summary

Commitment	LRA App. A Section	Type of Commitment	Scope
Chemistry Control Programs	16.2.6	Existing	See Below
Primary Chemistry Monitoring Program	16.2.6.1	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Secondary Chemistry Monitoring Program	16.2.6.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Auxiliary Systems Chemistry Monitoring Program	16.2.6.3	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Diesel Fuel Monitoring Program	16.2.6.4	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Service Water Chemical Control Program	16.2.6.5	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program	16.2.7	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Fire Protection Program	16.2.8	Existing	See Below
Fire Barrier Inspections	16.2.8.1	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Fire Hose Station Inspections	16.2.8.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Fire Suppression Water Supply System Surveillance	16.2.8.3	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Fire Suppression Sprinkler System Surveillance	16.2.8.4	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Fire Water Piping Thickness Evaluation	16.2.8.5	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Control Room Halon Fire System Inspection	16.2.8.6	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
RCP Oil Collection System Inspection	16.2.8.7	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Flow Accelerated Corrosion Prevention Program	16.2.9	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Inspection and Preventive Maintenance of the ANO-1 Polar Crane	16.2.10	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Instrument Air Quality Program	16.2.11	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Leakage Detection in Reactor Building	16.2.12	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Maintenance Rule Program	16.2.13	Modified	LR Commitment – Credit is taken for existing system and structural walkdowns. New Site Activity – Incorporate additional guidance for coatings inspection as part of existing system and structural walkdowns prior to May 20, 2014.
Oil Analysis Program	16.2.14	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Preventive Maintenance	16.2.15	Modified	LR Commitment – Credit is taken for existing activities. New Site Activity – Prior to May 20, 2014, add new PM activities to better address inspection criteria for aging effects.

ANO-1 LRA Commitments Summary

Commitment	LRA App. A Section	Type of Commitment	Scope
Reactor Building Leak Rate Testing Program (ILRT and LLRT)	16.2.16	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Reactor Building Sump Closeout Inspection	16.2.17	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Reactor Vessel Integrity Program	16.2.18 and 16.3.1	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Service Water Integrity Program	16.2.19	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Steam Generator Integrity Program	16.2.20	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
System and Component Monitoring, Inspections and Testing	16.2.21	Existing	See Below
Annual Emergency Cooling Pond Sounding	16.2.21.1	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Battery Quarterly Surveillance	16.2.21.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Control Room Ventilation Testing	16.2.21.3	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Core Flood Tank Monitoring	16.2.21.4	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Emergency Diesel Generator Testing and Inspections	16.2.21.5	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Emergency Feedwater Pump Testing	16.2.21.6	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
NaOH Tank Level Monitoring	16.2.21.7	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
Spent Fuel Pool Level Monitoring	16.2.21.8	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.

ANO-1 LRA Commitments Summary

Commitment	LRA App. A Section	Type of Commitment	Scope
TLAA – NRC Bulletin 88-08 commitments as modified by Risk Informed ISI	16.3.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
TLAA – NRC Bulletin 88-11 commitments as modified by Risk Informed ISI	16.3.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
TLAA – Augmented ISI of HPI/MU Nozzles	16.3.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
TLAA – Transient Cycle Logging and Tracking	16.3.2	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
TLAA – Environmental Qualification Program	16.3.3	Modified	New Site Activity – Prior to May 20, 2014, update EQ documentation to incorporate assessment results for a 60-year design life or replacement of components that are not qualified for the extended period of operation.
TLAA – Reactor Building Tendon Prestress	16.3.4	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.
TLAA – Boraflex Monitoring, GL 96-04 Commitment	16.3.6	Existing	LR Commitment – Credit is taken for existing activities, no new activities involved.

License Renewal Application

Arkansas Nuclear One - Unit 1

PREFACE

The following discussion describes where information is located in the ANO-1 License Renewal Application.

Section 1.0 provides the administrative information required by 10CFR54.17 and 10CFR54.19.

Section 2.0 provides the scoping and screening methodology. Section 2.0 describes and justifies the methodology used to determine the systems, structures, and components within the scope of license renewal and the structures and components subject to an aging management review. Section 2.0 identifies the set of plant-specific design basis events that were used to determine the systems, structures, and components within the scope of license renewal, consistent with the plant's current licensing basis. Tables 2.2-1 and 2.2-2 provide a list of the plant systems and structures, respectively, and identify those plant systems and structures that are within the scope of license renewal. Section 2.0 provides a description of systems, intended functions, and references to system boundary drawings. Tables 2.3-1, 2.3-6, 2.3-7, and 2.3-8 show the drawing numbers for the systems in the scope of license renewal. The drawings are provided in a separate submittal. Tables in Section 3.0 are referenced in Section 2.0.

Section 3.0 describes the results of the aging management reviews of the components and structures requiring aging management reviews. Furthermore, Section 3.0:

- identifies the components and structures subject to aging management review and their intended functions,
- describes or references the processes used to identify aging effects requiring management (Appendix C summarizes the process used to identify aging effects associated with non-Class 1 mechanical components, which encompasses engineered safeguards system, auxiliary system, and steam and power conversion system components),
- discusses the materials and environments which produce aging effects,
- identifies the aging effects requiring management,
- describes industry and operating experience with respect to the applicable aging effects, and
- identifies the aging management programs that will manage the aging effects requiring management.

Section 3.0 refers to the aging management programs but does not describe the aging management programs nor discuss how the programs will manage the aging effects requiring management. Appendix B describes these programs and provides the information necessary to demonstrate that the aging effects requiring management will be adequately managed. The tables in Section 3.0 provide a comprehensive summary of information concerning the aging effects requiring management for component and commodity groupings in the scope of license renewal. For the component and commodity groupings that make up the system or structure, the tables list intended function, material, environment, aging effect, and the aging management programs and activities.

Section 4.0 includes a list of time-limited aging analyses, as defined by 10CFR54.3. It includes the identification of the component or subject and an explanation of the time-dependent aspects of the calculation or analysis. Section 4.0 includes a demonstration that the analyses remain valid for the period of extended operation, the analyses have been projected to the end of the period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Section 4.0 also states that no 10CFR50.12 exemptions involving a time-limited aging analysis as defined in 10CFR54.3 are required during the period of extended operation.

Appendix A, Safety Analysis Report Supplement, provides a summary description of the programs and activities for managing the effects of aging for the period of extended operation. A summary description of the evaluation of time-limited aging analyses for the period of extended operation is also included.

Appendix B, Aging Management Programs and Activities, describes the aging management programs and activities and demonstrates that the aging effects on the components and structures within the scope of the license renewal rule will be managed such that they will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The ANO-1 programs and activities that are credited for managing aging are divided into new actions and existing actions.

Appendix C, Process for Identifying Aging Effects Requiring Aging Management for Non-Class 1 Mechanical Components, summarizes the process through which the applicable aging effects were identified and associated with the non-Class 1 mechanical components determined to be subject to an aging management review.

Appendix D, Technical Specification Changes, concludes that no technical specification changes are necessary to manage the effects of aging during the period of extended operation.

The information in Section 2.0, Section 3.0, and Appendix B fulfills the requirements in 10CFR54.21(a). The information in Section 4.0 fulfills the requirements in 10CFR54.21(c). The information in Appendix A and Appendix D fulfills the requirements in 10CFR54.21(b) will be met. The supplement to the environmental report required by 10CFR54.21(d) and 10CFR54.22, respectively. Section 1.4 discusses how the requirements in 10CFR54.23 is provided with the ANO-1 LRA as a separate document.

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Acronyms and Abbreviations

AAC	Alternate AC
AC	Alternating Current
ACI	American Concrete Institute
ACW	Auxiliary Cooling Water
AEC	Atomic Energy Commission
AISC	American Institute for Steel Construction
AMSAC	ATWS Mitigation System Actuation Circuit
ANO	Arkansas Nuclear One
ANO-1	Arkansas Nuclear One, Unit 1
ANO-2	Arkansas Nuclear One, Unit 2
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without SCRAM
B&PV	Boiler and Pressure Vessel
BAW (B&W)	Babcock and Wilcox
BWOG	Babcock and Wilcox Owners Group
BWST	Borated Water Storage Tank
CASS	Cast Austenitic Stainless Steel
CFR	Code of Federal Regulations
CIRSE	CRDM Nozzle PWSCC Inspection and Repair Strategic Evaluation
CLB	Current Licensing Basis
CPE	Chlorinated Polyethylene
CRDM	Control Rod Drive Mechanism
CRDSS	Control Rod Drive Service Structure
CSPE	Chlorosulfonated Polyethylene
CST	Condensate Storage Tank
CuNi	Copper-Nickel
C_vUSE	Charpy Upper-Shelf Energy
DBA	Design Basis Accident
DC	Direct Current
DH	Decay Heat
DHR	Decay Heat Removal
DOR	Division of Operating Reactors
DROPS	Diverse Reactor Overpressure Protection System
DSS	Diverse SCRAM System
EAI	Entergy Arkansas, Inc.
ECCS	Emergency Core Cooling System
ECP	Emergency Cooling Pond
EDG	Emergency Diesel Generator
EFPD	Effective Full Power Days
EFPY	Effective Full Power Years

Acronyms and Abbreviations

EFW	Emergency Feedwater
EHC	Electro-Hydraulic Control
EOI	Entergy Operations, Inc.
EP	Ethylene Propylene
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQ-TAP	EQ Task Action Plan
ER	Applicant's Environmental Report – Operating License Renewal Stage
ES	Engineered Safeguards
ESF	Engineered Safeguards
eV	Electron Volt
FIV	Flow Induced Vibration
FMR	Okonite Cable Trademark
FR	Flame Resistant
FR-EP	Flame Resistant Ethylene Propylene
FR-EPDM	Flame Retardant Ethylene Propylene Diene Monomer
FSAR	Final Safety Analysis Report
FTI	Framatome Technologies, Inc.
GL	Generic Letter
GLRP	Generic License Renewal Program
gpm	Gallons per Minute
GSI	Generic Safety Issue
H&V	Heating and Ventilation
HELB	High Energy Line Break
HEPA	High-Efficiency Particulate Air
HPI	High Pressure Injection
HVAC	Heating, Ventilation, and Air Conditioning
IASCC	Irradiation-Assisted Stress Corrosion Cracking
ICW	Intermediate Cooling Water
IE	Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IGA	Intergranular Attack
ILRT	Integrated Leak Rate Testing
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IPCEA	Insulated Power Cable Engineers Association
IRT	Initial Reference Temperature
ISI	Inservice Inspection
ISFSI	Independent Spent Fuel Storage Installation

Acronyms and Abbreviations

IST	Inservice Test
ITG	Issues Task Group
ITT	International Telephone and Telegraph
IWB	Subsection IWB of ASME Section XI Code
IWC	Subsection IWC of ASME Section XI Code
IWD	Subsection IWD of ASME Section XI Code
IWE	Subsection IWE of ASME Section XI Code
IWF	Subsection IWF of ASME Section XI Code
IWL	Subsection IWL of ASME Section XI Code
kip	Kilopound
kJ	Kilojoule
ksi	Kilopounds per Square Inch
KV	Kilovolt
KVA	Kilovolt-Ampere
KW	Kilowatt
LBB	Leak Before Break
LLRWB	Low Level Radwaste Building
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
LR	License Renewal
LRA	License Renewal Application
MFW	Main Feedwater
mg	Milligram
MIC	Microbiologically Induced Corrosion
MIRVP	Master Integrated Reactor Vessel Surveillance Program
mm	Millimeter
MOV	Motor Operated Valve
MSSV	Main Steam Safety Valve
MU	Makeup
MUP	Makeup and Purification
MW	Megawatt
MW(e)	Megawatt Electric
MW(t)	Megawatt Thermal
NaOH	Sodium Hydroxide
NDE	Nondestructive Examination
NDTT	Nil-Ductility Transition Temperature
NEI	Nuclear Energy Institute (formerly NUMARC)
NFPA	National Fire Protection Association
Ni	Nickel
Np	Neptunium
NPRDS	Nuclear Plant Reliability Data System
NPS	Nominal Pipe Size

Acronyms and Abbreviations

NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Management and Resources Council (now NEI)
OTSG	Once-Through Steam Generator
ppb	Parts per Billion
P&ID	Piping and Instrumentation Diagram
P-T	Pressure-Temperature
PASS	Post-Accident Sampling System
PM	Preventive Maintenance
PORV	Power-Operated Relief Valve
PSAR	Preliminary Safety Analysis Report
PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
Q	Safety-related
QA	Quality Assurance
Q-CST	Safety-Related Condensate Storage Tank
RAI	Request for Additional Information
RB	Reactor Building
RBS	Reactor Building Spray
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RI-ISI	Risk-Informed Inservice Inspection
RPV	Reactor Pressure Vessel
RT	Reference Temperature
RTE	Resistance Temperature Element
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVIAMP	Reactor Vessel Internals Aging Management Program
RVLMS	Reactor Vessel Level Monitoring System
SAR	Safety Analysis Report
SCC	Stress Corrosion Cracking
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SMAW	Shielded Metal Arc Welding
SOC	Statements of Consideration
SR	Silicone Rubber
SRP	Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants – LWR Edition
SS	Stainless Steel
SSC	System, Structure, Component
SSHT	Surveillance Specimen Holder Tubes

Acronyms and Abbreviations

SW	Service Water
TID	Total Integrated Dose
TLAA	Time-Limited Aging Analysis
TMI	Three-Mile Island
UBC	Uniform Building Code
USAR	Updated Safety Analysis Report
USAS	USA Standards Institute
USE	Upper Shelf Energy
V	Volt
XLPE	Cross-linked Polyethylene

1.0 ADMINISTRATIVE INFORMATION

1.1 Purpose and General Information

As the current operating license holder for ANO-1, Entergy Operations has prepared this application to provide the technical information required by 10CFR54 for the submittal of a License Renewal Application. This LRA and its supporting Applicant's Environmental Report - Operating License Renewal Stage are intended to provide sufficient information for the NRC to complete its technical and environmental reviews. The LRA and ER are designed to allow the NRC to make the finding required by 10CFR54.29 in support of the issuance of a renewed operating license for ANO-1. Following is the general information required by 10CFR54.17 and 10CFR54.19.

1.1.1 Name of Applicant

Entergy Operations, Inc. (operator) and Entergy Arkansas, Inc. (owner)

1.1.2 Address of Applicant

Entergy Operations (ANO-1)
1448 State Road 333
Russellville, AR 72802

1.1.3 Description of Business or Occupation of Applicant

Entergy Operations is an operating subsidiary of the Entergy Corporation, which is an investor-owned utility. Entergy Operations is engaged in the production of electric power primarily for portions of the states of Arkansas, Mississippi, Louisiana, and Texas. As a major part of this electricity production, Entergy Operations operates five nuclear power plants with a combined capacity of approximately 4875 megawatts.

1.1.4 Organization and Management of Applicant

Entergy Operations and Entergy Arkansas are public utilities incorporated under the laws of the State of Delaware. The Entergy Operations and Entergy Arkansas principal offices are located in Jackson, Mississippi and Little Rock, Arkansas, respectively, at the following addresses:

Entergy Operations, Inc.
1340 Echelon Parkway
Jackson, MS 39213

Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201

Entergy Operations and Entergy Arkansas are not owned, controlled, or dominated by any alien, a foreign corporation, or foreign government. Entergy Operations and Entergy Arkansas make this application on their own behalf and are not acting as an agent or representative of any other person.

The names and addresses of the Entergy Operations and Entergy Arkansas directors and principal officers, all of whom are citizens of the United States, are as follows:

Directors of Entergy Operations, Inc.

Name	Address
Jerry Yelverton (EOI Chairman)	Jackson, Mississippi
Donald C. Hintz	New Orleans, Louisiana
C. John Wilder	New Orleans, Louisiana

Principal Officers of Entergy Operations, Inc.

Name	Address
Jerry W. Yelverton President and Chief Executive Officer	Jackson, Mississippi
C. John Wilder Executive Vice President and Chief Financial Officer	New Orleans, Louisiana
John R. McGaha Executive Vice President and Chief Operating Officer	Jackson, Mississippi
C. Gary Clary Senior Vice President-Human Resources and Administration	New Orleans, Louisiana
William A. Eaton Vice President-Operations (Grand Gulf)	Port Gibson, Mississippi
Randall K. Edington Vice President-Operations (River Bend)	St. Francisville, Louisiana
Joseph T. Henderson Vice President and General Tax Counsel	New Orleans, Louisiana
C. Randy Hutchinson Vice President-Operations (Arkansas Nuclear One)	Russellville, Arkansas
Charles M. Dugger Vice President-Operations (Waterford-3)	Killona, Louisiana
Nathan E. Langston Vice President and Chief Accounting Officer	New Orleans, Louisiana
Steven C. McNeal Vice President and Treasurer	New Orleans, Louisiana
Fred W. Titus Vice President-Engineering	Jackson, Mississippi
Joseph L. Blount Secretary	Jackson, Mississippi

Directors of Entergy Arkansas, Inc.

Name	Address
Thomas J. Wright (EAI Chairman)	Little Rock Arkansas
Donald C. Hintz	New Orleans, Louisiana
C. John Wilder	New Orleans, Louisiana

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Thomas J. Wright President and Chief Executive Officer	Little Rock, Arkansas
C. John Wilder Executive Vice President and Chief Financial Officer	New Orleans, Louisiana
C. Gary Clary Senior Vice President-Human Resources and Administration	New Orleans, Louisiana
Frank F. Gallaher Senior Vice President, Generation, Transmission and Energy Mgmt.	New Orleans, Louisiana
Michael G. Thompson Senior Vice President, General Counsel and Secretary	New Orleans, Louisiana
Cecil L. Alexander Vice President-State Governmental Affairs	Little Rock, Arkansas
Joseph T. Henderson Vice President and General Tax Counsel	New Orleans, Louisiana
Nathan E. Langston Vice President and Chief Accounting Officer	New Orleans, Louisiana
Steven C. McNeal Vice President and Treasurer	New Orleans, Louisiana

1.1.5 Class and Period of License Sought

Entergy Operations requests renewal of the Class 104b operating license (reference 10CFR50.21(b)(1)) for ANO-1 (License No. DPR-51) for a period of 20 years beyond the expiration of the current license. The current license expires at midnight on May 20, 2014. Entergy Operations also requests renewal of those source, special nuclear material, and byproduct licenses that are combined in the operating license.

The facility will continue to be known as ANO-1 and will continue to generate electric power. ANO-1 is designed to operate at core power levels up to 2568 MW(t), which corresponds to a maximum dependable output electrical generation capacity of 836 net MW(e).

1.1.6 Earliest and Latest Dates for Alterations, if Proposed

Entergy Operations does not propose to construct or alter a production or utilization facility in connection with this application.

1.1.7 Conforming Changes to the Standard Indemnity Agreement

10CFR54.19(b) requires that conforming changes to the Standard Indemnity Agreement, Appendix B of 10CFR140.92, to account for the expiration term of the proposed renewed license be included in the application. The current Standard Indemnity Agreement for ANO-1 states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the attachment to the Standard Indemnity Agreement. Item 3 of the attachment to the Standard Indemnity Agreement, as revised by Amendment No. 6, lists DPR-51 as an applicable license number. Entergy Operations requests that conforming changes be made to Article VII of the Standard Indemnity Agreement, and/or Item 3 of the attachment to the Standard Indemnity Agreement, specifying the extension of the Standard Indemnity Agreement until the expiration date of the renewed ANO-1 Operating License. Should the license number be changed upon issuance of the renewed license, Entergy Operations requests that conforming changes be made to Item 3 of the attachment and to any other sections of the Standard Indemnity Agreement as appropriate.

1.1.8 Restricted Data Agreement

As required by 10CFR50.37 and 10CFR54.17(g), Entergy Operations, as a part of the application for a renewed license for ANO-1, hereby agrees that it will not permit any individual to have access to, or any facility to possess, restricted data or classified national security information until the individual and/or facility has been approved for such access under the provisions of 10CFR Part 25 and/or 10CFR Part 95. This application does not contain restricted data or other national security information.

1.2 Plant Description

The ANO site is located in southwestern Pope County, Arkansas, on a peninsula formed by Lake Dardanelle. ANO-1 was constructed from 1968 until 1974. The unit consists of a Babcock and Wilcox pressurized water reactor nuclear steam supply system designed to generate 2568 MW(t), or approximately 836 net MW(e). The current facility operating license for ANO-1 expires at midnight May 20, 2014. The ANO-1 station consists primarily of an individual reactor building, an auxiliary building, an intake structure, and a common turbine building (shared with ANO-2, a Combustion Engineering PWR NSSS).

Entergy Operations operates an independent spent fuel storage installation in accordance with 10CFR Part 72 at ANO. The independent spent fuel storage installation is an independent facility subject to separate licensing and renewal provisions under 10CFR Part 72. The independent spent fuel storage installation is not within scope of 10CFR Part 54 or this application.

1.3 Technical Information Required for an Application

10CFR54.21 requires four technical items to support an application for a renewed operating license. These are an integrated plant assessment (Sections 2.0 and 3.0), an evaluation of time-limited aging analyses (Section 4.0), a supplement to the ANO-1 Safety Analysis Report (sometimes referred to as the USAR or FSAR) which contains a summary description of the programs and activities for managing the effects of aging and the evaluation of the time-limited aging analyses (Appendix A), and current licensing basis changes during NRC review (Section 1.4)

In addition to the technical information, 10CFR54.22 requires applicants to submit any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation (Appendix D). 10CFR54.23 requires the application to include a supplement to the environmental report (Applicant's Environmental Report – Operating License Renewal Stage).

The IPA, as defined by 10CFR54.3, is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with 10CFR54.21(a) for license renewal have been identified. The IPA also demonstrates that the effects of aging on the functionality of such structures and components will be managed to maintain the current licensing basis during the period of extended operation. The ANO-1 IPA includes:

- identification of the structures and components within the scope of license renewal that are subject to an aging management review;
- identification of the aging effects applicable to these structures and components;
- identification of plant-specific programs and activities that will manage these identified aging effects; and
- a demonstration that these programs and activities will be effective in managing the effects of aging during the period of extended operation.

The ANO-1 IPA for license renewal, along with other information necessary to document compliance with 10CFR54, is maintained in an auditable and retrievable form in accordance with 10CFR54.37(a). The ANO-1 IPA is documented with site-specific reports and calculations which were generated in accordance with onsite administrative procedures. Also, note that references to the ANO-1 Technical Specifications and SAR are as of Amendment 202 and Amendment 15, respectively.

1.4 Current Licensing Basis Changes during NRC Review

Each year, following the submittal of the ANO-1 LRA, and at least three months before the scheduled completion of the NRC review, Entergy Operations will submit amendments to the application pursuant to 10CFR54.21(b). The revision will identify any changes to the current licensing basis that materially affect the contents of the LRA and any other aspects of the application.

2.0 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 Introduction

Section 2.0 describes the first major activity of the ANO-1 integrated plant assessment, the identification of structures and components subject to aging management review. The information provided in Section 2.0 is intended to meet the requirements of 10CFR54.21(a)(1) and 10CFR54.21(a)(2).

ANO-2 and the independent spent fuel storage installation structures, and components were not included in the IPA, since they have separate licenses from the ANO-1 operating license. However, certain common systems, structures, and components that are shared by ANO-1 and ANO-2 are included in the IPA, since they meet the criteria for being in scope for ANO-1.

For those systems, structures, and components within the scope of license renewal (defined by 10CFR54.4), 10CFR54.21(a)(1) requires a license renewal applicant to identify and list the structures and components subject to aging management review. 10CFR54.21(a)(2) further requires that the methods used to identify and list these structures and components be described and justified. The information in this section serves to satisfy these requirements. Overall, the information provided in Sections 2.0 and 3.0 provides the basis for the NRC to make the finding required by 10CFR54.29(a)(1).

The ANO-1 IPA is divided into the areas of mechanical, civil/structural, and electrical. The results of the assessment to identify the systems and structures within the scope of license renewal (scoping) are contained in Section 2.2. The results of the identification of the components and structures subject to aging management review (screening) are contained in Section 2.3 for mechanical components, Section 2.4 for structures, and Section 2.5 for electrical commodities.

2.1.2 Assessment Using Criteria in 10CFR54.4

The ANO-1 IPA followed the process recommended in NEI 95-10 (Reference 2.1-1) to determine the systems, structures, and components in the scope of license renewal. This section discusses the assessment performed to identify structures, systems, and components that satisfy the criteria in 10CFR54.4(a)(1), 10CFR54.4(a)(2), and 10CFR54.4(a)(3).

Safety-Related Criteria Pursuant to 10CFR54.4(a)(1)

10CFR54.4(a)(1) states that the systems, structures, and components within the scope of license renewal include:

Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10CFR50.49(b)(1)) to ensure the following functions:

- The integrity of the reactor coolant pressure boundary;
- The capability to shut down the reactor and maintain it in a safe shutdown condition; or
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10CFR50.34(a)(1) or 10CFR100.11 of this chapter, as applicable.

In the ANO-1 SAR Table 1-2, "safety-related" or "Q" is defined based on 10CFR Part 100, Appendix A, as the structures, systems, and components required to assure:

(1) the integrity of the reactor coolant pressure boundary,

(2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or

(3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite doses comparable to the guideline doses of 10CFR Part 100.

A summary level Q-list for ANO-1 structures and systems is provided in the ANO-1 SAR Table 1-2.

In the mid-1980's, Entergy Operations implemented a component level Q-list project, which classified "Q" devices at the component level. This component level Q-list is maintained in a component database at ANO. The ANO-1 summary and component level Q-lists include those systems, structures, and components relied on to remain functional during or following design basis events described in SAR Chapter 14. The postulated events in SAR Chapter 14 include:

- Uncompensated operating reactivity changes
- Startup accident
- Rod withdrawal accident at rated power operation
- Moderator dilution accident
- Cold water accident

- Loss of coolant flow
- Stuck-out, stuck-in, or dropped control rod accident
- Loss of electric power
- Turbine overspeed
- Fuel loading errors
- Steam line failure
- Steam generator tube failure
- Fuel handling accident
- Rod ejection accident
- Loss of coolant accident
- Maximum hypothetical accident
- Waste gas tank rupture

In summary, the ANO-1 summary and component level Q-lists were used during the IPA to identify ANO-1 systems, structures, and components that are safety-related. Since the ANO-1 summary and component level Q-lists include safety-related systems, structures, and components for ANO-1, this process to identify systems, structures, and components meets the criteria of 10CFR54.4(a)(1).

<u>Nonsafety-Related Criteria Pursuant to10CFR54.4(a)(2)</u>

10CFR54.4(a)(2) states that the systems, structures, and components within the scope of license renewal include:

"All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section."

At ANO-1, the majority of systems, structures, or components whose failure could impact a functionally related safety-related system are classified as safety-related. Therefore, except for a few cases, the systems and structures meeting these criteria have components on the ANO-1 Q-list and are included in the scope of license renewal under 10CFR54.4(a)(1).

Based on a review of the ANO-1 SAR and design documents, a few cases have been identified in which passive, long-lived, nonsafety-related components could impact safety-related functions.

- Spatially-related components in which the physical location could result in interaction between components. This includes seismic category 2 over 1 structures and components.
- Spent fuel pool liner is nonsafety-related as documented in the ANO-1 SAR, but has been included in the scope of license renewal. [Note: The acceptability of a nonsafety-related liner is acknowledged in footnote 1 of the NRC Standard Review

Plan (NUREG-0800), Section 9.1.2, "Spent Fuel Storage." This footnote states that for operating licenses issued before November 17, 1977, analysis of a nonsafety-related liner was not required and is not considered necessary since stresses in the liner in the event of a safe shutdown earthquake will be low and, therefore, liner failure is unlikely.]

In addition, a few nonsafety-related components were included in the scope of license renewal, although they do not meet the criteria of 10CFR54.4(a)(2). These additional components are

- nonsafety-related valves and piping that are part of the pressure boundary for the main steam lines and steam generators inside the reactor building, and
- certain nonsafety-related valves and piping in the auxiliary building sump system that are credited for preventing offsite releases.

In summary, the few cases in which ANO-1 nonsafety-related components could impact safety-related functions have been identified and the associated components have been included in the scope of license renewal in accordance with the criteria of 10CFR54.4(a)(2).

<u>Other Scoping pursuant to 10CFR54.4(a)(3)</u>

10CFR54.4(a)(3) states that the systems, structures, and components within the scope of license renewal include:

All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10CFR50.48), environmental qualification (10CFR50.49), pressurized thermal shock (10CFR50.61), anticipated transients without scram (10CFR50.62), and station blackout (10CFR50.63).

Scoping based on each of these regulations is addressed separately in the following sections:

<u>Commission's Regulations for Fire Protection (10CFR50.48)</u>

The original ANO-1 fire protection systems met General Design Criterion 3 of 10CFR Part 50, Appendix A. In 1980, the NRC issued 10CFR50.48 and 10CFR Part 50, Appendix R, to address new requirements. Three sections of 10CFR Part 50 Appendix R (Sections III.G, III.J, and III.O) impose new requirements on plants licensed prior to January 1, 1979, including ANO-1.

Section III.G required safe shutdown evaluations to ensure one train of safe shutdown equipment remained free of fire damage. A fire area reanalysis was performed at ANO-1 to evaluate the plant equipment required to place the plant in a safe shutdown condition for any single fire scenario. The fire analysis contains a listing of the ANO-1 components that can be used to place the plant in a safe condition following a fire. These components are in the license renewal scope.

Section III.J required emergency lighting for all necessary areas including access and egress. The emergency lighting system is included in the license renewal scope.

Section III.O required a seismic oil collection system be provided for the reactor coolant pumps. Entergy Operations requested and was granted an exemption from the requirements for a seismic reactor coolant pump oil collection system. The ANO-1 non-seismic reactor coolant pump oil collection system is in the license renewal scope.

In addition to the components discussed above, the ANO-1 component database includes nonsafety-related components (both mechanical and electrical) that are required to meet 10CFR50.48 requirements. These components are included in the license renewal scope.

For structural components and commodities, ANO-1 fire protection drawings and procedures were utilized to identify the fire doors, fire walls, and other fire barriers that are credited for compliance with 10CFR50.48 requirements. These structural components are in the license renewal scope.

Commission's Regulations for Environmental Qualification (10CFR50.49)

The Environmental Qualification Program at ANO is a centralized plant support program administered by design engineering in order to maintain compliance with 10CFR50.49. Electrical equipment located in a harsh environment which is important to safety, including safety-related (Q) equipment, nonsafety-related equipment whose failure could adversely affect safety-related equipment, and the necessary post-accident monitoring equipment is included in the scope of the program. The identification of equipment is specified by procedural controls and the component database is utilized to maintain an EQ equipment master list. The components in the EQ program were included in the ANO-1 license renewal scope.

Commission's Regulations for Pressurized Thermal Shock (10CFR50.61)

Pressurized thermal shock is an event, or transient, that causes a severe overcooling concurrent with, or followed by, significant pressure in the reactor vessel. The requirements in 10CFR50.61 identify specific operational limits for PTS pertaining to the belt-line region of the reactor vessel. If these limits are exceeded, the licensee must identify and submit a list of any plant modifications to systems, equipment, and operation to prevent a potential failure of the reactor vessel. ANO-1 will not exceed the PTS screening criteria during the license renewal period to 60 years, as addressed in Section 4.2.1. Since the PTS screening criteria are met, no structures, systems, or components are required for ANO-1 to comply with the PTS regulation. Therefore, no structures, systems, or components are included in the scope of license renewal to meet the PTS criterion of 10CFR54.4(a)(3).

Commission's Regulations for Anticipated Transients without Scram (10CFR50.62)

In 1990, Entergy Operations installed several instrumentation systems in ANO-1 for compliance with the Commission's regulations for anticipated transients without scram (10CFR50.62). A DROPS/DSS system was installed for a diverse reactor trip and a DROPS/AMSAC was installed for a backup actuation of EFW and a diverse main turbine trip. These systems place ANO-1 in compliance with 10CFR50.62 and provide plant protection in the event the reactor protection system fails to perform its function during an ATWS event. The components in the DROPS/DSS and the DROPS/AMSAC are included in the scope of license renewal.

Commissions Regulations for Station Blackout (10CFR50.63)

ANO-1 is committed to the regulatory requirements of 10CFR50.63 utilizing the design criteria/approach in NUMARC 87-00 (Reference 2.1-2) that is accepted by Regulatory Guide 1.155, "Station Blackout." An alternate AC diesel generator has been installed at ANO. The alternate AC diesel generator is in a separate structure and is totally independent of the other emergency power sources and their auxiliaries. The alternate AC diesel generator has its own air start system, fuel oil transfer pump/day tank, cooling, and lube oil subsystems. The mechanical components, electrical commodities, and structures that are needed for the alternate AC diesel generator to perform its function are included in the scope of license renewal.

In summary, the systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection, EQ, PTS, ATWS, and station blackout, have been included in the scope of license renewal in accordance with the criterion of 10CFR54.4(a)(3).

2.1.3 Assessment Using Criteria in 10CFR54.21(a)(1)

10CFR54.21(a)(1) states that structures and components subject to an aging management review shall encompass those structures and components:

(i) that perform an intended function, as described in 10CFR54.4, without moving parts or without a change in configuration or properties and,

(ii) that are not subject to replacement based on a qualified life or specified time period.

As part of the ANO-1 IPA, an assessment was performed using the ANO-1 SAR, component database, and design documents to identify the intended functions for the mechanical components, structures and structural components, and electrical commodities. The intended functions identified were based on the guidance of NEI 95-10.

Of the structures and components within the scope of 10CFR54.4, only those that are classified as long-lived and passive are subject to an aging management review. In other words, active components and those identified as having a periodic replacement schedule are not subject to an aging management review. The passive and long-lived structures and components at ANO-1 were identified using NEI 95-10 as a guide. The listing of identified structures and components and their intended functions is discussed in Section 2.3 for mechanical components, Section 2.4 for structures, and Section 2.5 for electrical commodities.

2.1.4 Generic Safety Issues

In accordance with the guidance in NEI 95-10, review of NRC generic safety issues as a part of the license renewal process is required to satisfy the finding required by 10CFR54.29. GSIs that involve an issue related to the license renewal aging management review or time-limited aging analysis evaluations are to be addressed in the LRA. Based on the NEI guidance, NUREG-0933, "A Prioritization of Generic Safety Issues" (Supplement 23), and the Oconee LRA, Entergy Operations has identified the following list of GSIs to be addressed in the ANO-1 LRA:

GSI 23 – Reactor Coolant Pump Seal Failures

GSI 23 has recently been closed by the NRC (Reference 2.1-3).

GSI 168 – Environmental Qualification of Electrical Equipment

This GSI is related to aging concerns with respect to environmental qualification of electrical equipment. Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for ANO-1; therefore, this GSI is addressed in Section 4.4.69.

GSI 173.A – Spent Fuel Storage Pool: Operating Facilities

The only age-related issue associated with this GSI is the potential degradation of Boraflex, which was identified in NRC Generic Letter 96-04 and is identified as a time-limited aging analysis for ANO-1. Therefore, this GSI is addressed in Section 4.7.

GSI 190 – Fatigue Evaluation of Metal Components for 60-Year Plant Life

This GSI addresses fatigue life of metal components. Fatigue evaluation of metal components is identified as a time-limited aging analysis for ANO-1. Therefore, this GSI is addressed in Section 4.3.

2.1.5 Conclusion

The methods described in Sections 2.1.1 through 2.1.4 were used at ANO-1 to identify the systems, structures, and components that are within the scope of license renewal and that require an aging management review. This is consistent with the requirements of 10CFR54.4 and 10CFR54.21(a)(1), respectively.

The list of the systems and structures in the scope of license renewal is included in Section 2.2. The more detailed listing of components, structures, and commodity groups and the associated intended functions is discussed in Section 2.3 for mechanical components, Section 2.4 for structures, and Section 2.5 for electrical commodities.

2.1.6 References for Section 2.1

2.1-1 NEI 95-10, "*Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule*," Revision 0, Nuclear Energy Institute, March 1996.

2.1-2 NUMARC 87-00, "*Guidelines and Technical Basis for NUMARC Initiatives Addressing Station Blackout at LWRs*," Revision 1, Nuclear Management and Resources Council, August 1991.

2.1-3 NRC letter from A. Thadani to W. Travers, dated November 8, 1999.

2.2 PLANT LEVEL SCOPING RESULTS

Table 2.2-1 lists the ANO-1 plant systems and the results of the evaluation that was performed to determine what systems contain components that meet the 10CFR54.4 criteria for being in the scope of license renewal. The systems are listed as being in the scope of license renewal if any of the components in the system meet the criteria of 10CFR54.4 as discussed in Section 2.1.2. Therefore, many nonsafety-related systems, in addition to those nonsafety-related systems discussed in Section 2.1.2, are identified in the table as being in the scope of license renewal only due to a limited number of components that require review at the electrical or mechanical interfacing boundaries. Section 2.2.1 provides additional detail on the assessment results provided in Table 2.2-1.

Table 2.2-2 lists ANO-1 plant structures and identifies which structures meet the 10CFR54.4 criteria for being in the scope of license renewal. Section 2.2.2 provides additional detail on the assessment results provided in Table 2.2-2.

2.2.1 Mechanical and Electrical Systems

The list of ANO-1 systems (mechanical and electrical) within the scope of license renewal was created as discussed in Section 2.1 and is documented in Table 2.2-1. The following information provides additional detail on the assessment process.

The ANO-1 reactor coolant system is a typical B&W pressurized water nuclear steam supply system with a reactor vessel, two steam generators, four reactor coolant pumps, a pressurizer, and the connecting or interfacing piping as the primary components. The RCS is an ASME Class 1 system that is safety-related and is, therefore, in the scope of license renewal. The components that maintain the RCS pressure boundary are in the scope of license renewal.

The non-Class 1 mechanical systems determined to meet the 10CFR54.4 criteria were included in the scope of review. Many of these systems (such as high pressure injection, low pressure injection, core flood, reactor building spray, emergency feedwater, reactor building cooling, emergency diesel generators, hydrogen control, penetration room ventilation, control room ventilation, etc.) have important safety functions under accident conditions and are clearly in the scope of license renewal. Other systems are needed to support these systems (such as service water, fuel oil, etc.) and are in the scope of license renewal, since they are required to operate under accident conditions to support the safety-related systems.

Some non-Class 1 systems required for normal plant operation (such as main feedwater and main steam) have a limited portion of the system that performs a safety-related function, and therefore, a portion of the system is included in the scope of license renewal. Portions of the instrument air system, that are necessary for the operation of safety-related valves and dampers, are Q-listed and are included in the scope of license renewal. The portions of the condensate storage and transfer system required to support emergency feedwater system operation are Q-listed and in the scope of license renewal. Portions of the chilled water systems, that support operation of safety-related cooling units, are Q-listed and in the scope of license renewal.

A number of non-Class 1 mechanical systems are in the scope of license renewal *only* due to their reactor building penetrations (the remainder of the system was not in scope) and were grouped together for aging management review. Some vent, drain and sampling systems are in the scope of license renewal because of Q-listed components at the interface with safety-related systems.

The halon system, portions of the fire protection system required to support 10CFR50.48, and the alternate AC diesel generator and supporting equipment are in the scope of license renewal per 10CFR54.4(a)(3).

The ANO-1 electrical systems include an offsite power supply from the switchyard, two essential trains (red and green) of onsite electrical distribution that supply power to safety-related components, and a non-safety grade power supply for nonsafety-related equipment. The 500kV switchyard is a non-Q power supply that is not in the scope of license renewal (except for some interfacing components) since the emergency diesel generators are the credited safety-related power supplies. The main generator excitation is required for normal plant operation, but is non-Q and is not in the scope of license renewal (except for some interfacing components).

The ANO-1 reactor coolant pumps are supplied by non-Q 6.9kV busses. The 6.9kV switchgear is not in the scope of license renewal, except for interfacing components and portions of the breakers that are credited with tripping the breaker in the 10CFR50.48 analysis (to ensure the reactor coolant pumps do not continue to operate and cause a seal failure if seal cooling is lost due to a fire).

The ANO-1 4.16kV switchgear system can be powered from offsite or onsite sources. The safety grade portions of this system supply power to the larger safety grade pump motors (high pressure injection, low pressure injection, service water, emergency feedwater, etc.) and the safety grade 480V load centers that supply power to many safety-related valves, coolers, and pumps. Therefore, the safety grade portions of the 4.16kV switchgear and 480V load centers are Q-listed and in the scope of license renewal as identified in Table 2.2-1.

The essential 125V DC system, including the safety-related station batteries, and the essential 120V AC system are Q-listed and in the scope of license renewal since they supply power to safety-related equipment under accident conditions.

The safety-related instrumentation systems (reactor protection, emergency feedwater initiation and control, engineered safeguards actuation, etc.) are in the scope of license renewal since they are Q-listed and credited in accident analyses. The ATWS mitigation, diverse scram, and diverse reactor overpressure protection systems are in the scope of license renewal since they are credited in the anticipated transients without scram (10CFR50.62) analysis. Many of the other control systems that are required to support normal plant operation (electro-hydraulic control, integrated control system) are non-Q and are not in the scope of license renewal (except for some interfacing components).

The electrical components associated with the alternate AC diesel generator (including the DC power supply), the fire detection system, the electrical controls of the fire protection system and the portion of the emergency lighting required for 10CFR50.48 are in the scope of license renewal per 10CFR54.4(a)(3).

2.2.2 Structures

The list of ANO-1 structures within the scope of license renewal was created by reviewing the SAR, site plans and general arrangement drawings, and other plant-specific documents as discussed in Section 2.1. The identification of safety-related structures and non-safety-related structures whose failure could prevent safety-related systems, structures, or components from fulfilling their safety-related functions was based on the classification of each ANO-1 structure as documented in SAR Table 1-2.

ANO-1 structures are designated as either seismic category 1 or seismic category 2. ANO-1 seismic category 1 structures are those which prevent uncontrolled release of radioactivity and are designed to withstand design basis loadings without loss of function as defined in the ANO-1 SAR. This classification is consistent with the intent of 10CFR54.4(a)(1). Therefore, Entergy Operations has determined that ANO-1 seismic category 1 structures meet the criteria contained in 10CFR54.4(a)(1), and are within the scope of license renewal.

Seismic category 2 structures are those structures whose limited damage would not result in a release of radioactivity, would permit a controlled plant shutdown, but could interrupt power generation. Chapter 5 of the SAR states that seismic category 2 structures do not perform a nuclear safety-related function but that their failure could possibly affect the function of a safety-related system. This classification is consistent with the intent of 10CFR54.4(a)(2). Therefore, Entergy Operations has determined that some ANO-1 seismic category 2 structures/building portions meet the criteria contained in 10CFR 54.4(a)(2), and are within the scope of license renewal.

The list of ANO-1 structures also includes those within the scope of license renewal that meet the criteria of 10CFR54.4(a)(3).

Table 2.2-1 Listing of ANO-1 Mechanical and Electrical Systems

SYSTEM	IN SCOPE	LRA SECTION(S)
4.16 KV Switchgear	X	2.5
120 V Instrument AC	X	2.5
120 VAC	X	2.5
125 V DC	X	2.5
480V Load Centers	X	2.5
500 KV	X[1]	2.5
6.9 KV Switchgear	X[1]	2.5
AAC Building Ventilation	X	2.3.3.5, 2.5
Administration Building Heating and Ventilation		Not in scope of LRA
Alternate AC Diesel Generator	X	2.3.3.5, 2.5
Annunciator	X[1]	2.5
Area Radiation Monitoring	X[1]	2.5
Atmospheric Vents		Not in scope of LRA
ATWS Mitigation	X	2.5
Auxiliary Building Drains		Not in scope of LRA
Auxiliary Building Equipment Vents		Not in scope of LRA
Auxiliary Building Heating and Ventilation	X	2.3.3.12, 2.5
Auxiliary Building Sump	X[1]	2.3.3.4
Auxiliary Cooling Water	X[1]	2.5
Breathing Air	X[1]	2.3.2.7
Carbon Dioxide		Not in scope of LRA
Cardox	X[2]	2.3.3.6, 2.5
Cathodic Protection		Not in scope of LRA
Chemical Addition	X[1]	2.3.2.4, 2.3.2.6, 2.5
Chilled Water	X	2.3.3.9, 2.5
Chlorination		Not in scope of LRA
Circulating Water		Not in scope of LRA
Clean Liquid Radwaste	X[1]	2.3.2.7, 2.5
Condensate Demineralizer	X[1]	2.5
Condensate Storage & Transfer	X	2.3.4.4, 2.5
Condenser Vacuum		Not in scope of LRA
Control Rod Drive	X	2.3.1.5, 2.3.1.9, 2.5

Table 2.2-1 Listing of ANO-1 Mechanical and Electrical Systems

SYSTEM	IN SCOPE	LRA SECTION(S)
Control Room Ventilation	X	2.3.3.13, 2.5
Core Flood	X	2.3.2.1, 2.5
Decay Heat	X	2.3.2.2, 2.5
Dirty Liquid Radwaste	X[1]	2.5
Dirty Water Drain	X[1]	2.3.3.4
Diverse Reactor Over-Pressure Protection	X	2.5
Diverse SCRAM	X	2.5
Domestic Water		Not in scope of LRA
Electro-Hydraulic Control	X[1]	2.5
Emergency Diesel Generator	X	2.3.3.3, 2.5
Emergency Feedwater	X	2.3.4.3, 2.5
Emergency Feedwater Initiation and Control	X	2.5
Emergency Lighting	X	2.5
Emergency Operations Facility		Not in scope of LRA
Engineered Safeguards Actuation	X	2.5
Extraction Steam		Not in scope of LRA
Feedwater Pump Lube Oil		Not in scope of LRA
Fire Detection	X	2.5
Fire Protection	X	2.3.3.2, 2.5
Fuel Handling	X[4]	2.4.2.1
Fuel Oil	X	2.3.3.7, 2.5
Gas Collection Header	X[1]	2.3.2.8
Gaseous Effluent Radiation Monitoring		Not in scope of LRA
Gaseous Radwaste	X[1]	2.3.2.7, 2.5
Generator Seal Oil		Not in scope of LRA
Gland Steam		Not in scope of LRA
Halon	X	2.3.3.6, 2.5
Heat Tracing	X[1]	2.5
Heater Drains		Not in scope of LRA
Heater Vents	X[1]	2.3.2.7, 2.3.4.1
High Pressure Injection	X	2.3.2.3, 2.5

Table 2.2-1 Listing of ANO-1 Mechanical and Electrical Systems

SYSTEM	IN SCOPE	LRA SECTION(S)
Hydrogen	X[1]	2.5
Hydrogen Purge	X[1]	2.3.2.8, 2.5
Hydrogen Recombiners	X	2.3.2.8, 2.5
Inadequate Core Cooling	X	2.5
Incore Instrumentation	X	2.3.1.3, 2.5
Instrument Air	X[1]	2.3.3.8, 2.5
Integrated Control	X[1]	2.5
Intermediate Cooling	X[1]	2.3.2.7, 2.3.2.8, 2.5
Isophase Bus		Not in scope of LRA
Isophase Bus Cooling	X[1]	2.5
Laundry Radwaste		Not in scope of LRA
Low Pressure Injection	X	2.3.2.2, 2.5
Lube Oil	X[1]	2.5
Main Chiller Cooling Water		Not in scope of LRA
Main Feedwater	X	2.3.4.2, 2.5
Main Generator Excitation	X[1]	2.5
Main Steam	X	2.3.4.1, 2.5
Main, Auxiliary and Startup Transformers	X[1]	2.5
Makeup and Purification	X	2.3.2.3, 2.5
Meteorological		Not in scope of LRA
Miscellaneous Turbine Drains		Not in scope of LRA
Neutralizing Tank		Not in scope of LRA
Nitrogen Supply	X[1]	2.3.1.3, 2.3.2.7, 2.3.4.1, 2.5
Non-Nuclear Instrumentation	X	2.5
Nuclear Instrumentation	X	2.5
Oily Water Separator		Not in scope of LRA
Particulate Air Monitoring	X[1]	2.5
Penetration Room Ventilation	X	2.3.3.11, 2.5
Plant Computer		Not in scope of LRA
Plant Heating	X[1]	2.3.2.7, 2.5
Plant Makeup	X[1]	2.5
Plant Performance Analysis		Not in scope of LRA
Post Accident Sampling	X[1]	2.3.1.3, 2.3.2.2, 2.5

Table 2.2-1 Listing of ANO-1 Mechanical and Electrical Systems

SYSTEM	IN SCOPE	LRA SECTION(S)
Process Radiation Monitoring.	X[1]	2.5
Quindar		Not in scope of LRA
Radiation Monitoring		Not in scope of LRA
Radiation Dose Assessment		Not in scope of LRA
Reactor Building Drains	X	2.3.1.3, 2.3.3.4
Reactor Building Heating and Ventilation	X	2.3.2.5, 2.5
Reactor Building Purge	X[1]	2.3.2.5
Reactor Building Spray	X	2.3.2.4, 2.3.3.4, 2.5
Reactor Building Sump	X	2.3.3.4, 2.5
Reactor Building Vents	X	2.3.1.9
Reactor Coolant	X	2.3.1, 2.3.3.4, 2.5
Reactor Coolant Pump (Support Equipment)	X	2.5
Reactor Core	X[3]	
Reactor Protection	X	2.5
Regenerative Waste	X[1]	2.5
Reheat Steam		Not in scope of LRA
Resin Transfer		Not in scope of LRA
Safety Parameter Display	X[1]	2.5
Sampling	X[5]	2.5
Screen Wash	X[1]	2.5
Security	X[1]	2.5
Seismic Monitoring		Not in scope of LRA
Service Air	X[1]	2.3.2.4
Service Water	X	2.3.3.10, 2.5
Sewage Treatment		Not in scope of LRA
Smart Auto Signal Selection		Not in scope of LRA
Spent Fuel	X	2.3.3.1, 2.5
Spent Resin		Not in scope of LRA
Startup Boiler		Not in scope of LRA
Turbine Building Ventilation	X[4]	2.4.6.2
Turbine Building Sump		Not in scope of LRA
Turbine Generator	X[1]	2.5

Table 2.2-1 Listing of ANO-1 Mechanical and Electrical Systems

SYSTEM	IN SCOPE	LRA SECTION(S)
Vibration and Loose Parts Monitoring		Not in scope of LRA
Waterbox Vacuum		Not in scope of LRA

NOTES:
'X' – Denotes system is within the scope of license renewal

1. A small portion of the system is in scope
2. Halon portion only
3. Not subject to aging management review due to periodic component replacement
4. Structural portions only
5. Mechanical components in scope are contained in several systems (Refer to scoping drawings).

Table 2.2-2 Listing of ANO-1 Structures		
STRUCTURE	**IN SCOPE**	**CORRESPONDING LRA SECTION(S)**
Administration Building		Not in scope of LRA
Alternate AC Diesel Generator Building Foundation	X	2.4.6.1
Auxiliary Building	X[2]	2.4.3
Boathouse		Not in scope of LRA
Borated Water Storage Tank Foundation	X[1]	2.4.6.1
Bottle Storage Building		Not in scope of LRA
Bulk Fuel Oil Storage Tank Foundation	X	2.4.6.1
Caustic Acid Building		Not in scope of LRA
Central Support Building		Not in scope of LRA
Chemical Flush Discharge Pond		Not in scope of LRA
Chemical Treatment Building		Not in scope of LRA
Condensate Storage Tank Foundation and Pipe Trenches	X	2.4.6.1
Controlled Access #3		Not in scope of LRA
Crafts Fabrication Shop		Not in scope of LRA
Deluge Valve Building		Not in scope of LRA
Electrical Manholes	X	2.4.6.1
Emergency Cooling Pond/ Intake/Discharge Canals	X	2.4.5
Emergency Diesel Fuel Oil Storage Tank Vault	X	2.4.6.1
Engineering Building		Not in scope of LRA
Fire Fighting Equipment Hose Houses next to Hydrant H1 through H11.		Not in scope of LRA
Fire Training Smoke House		Not in scope of LRA
Generation Support Building		Not in scope of LRA
Hydrogen and CO_2 Building		Not in scope of LRA
Incinerator Building		Not in scope of LRA
Intake Structure	X[2,3]	2.4.4
LLRWB SPING Unit Shelter		Not in scope of LRA

Table 2.2-2 Listing of ANO-1 Structures		
STRUCTURE	**IN SCOPE**	**CORRESPONDING LRA SECTION(S)**
Maintenance Building		Not in scope of LRA
North Gate Guard House		Not in scope of LRA
Off-Site Fabrication Building		Not in scope of LRA
Oily Water Separator Building		Not in scope of LRA
Old Administration Building		Not in scope of LRA
Paint and Lube Oil Storage Building		Not in scope of LRA
Post Accident Sampling System Building	X	2.4.3
Radioactive Waste Building		Not in scope of LRA
Radwaste Storage Building		Not in scope of LRA
Reactor Building	X[2]	2.4.1 and 2.4.2
Secondary Guard House		Not in scope of LRA
Security Compliance Building		Not in scope of LRA
Start-up Boiler Building		Not in scope of LRA
Sullair Air Compressor Building		Not in scope of LRA
Technical Support Building		Not in scope of LRA
Turbine Building	X[4]	2.4.3 and 2.4.6.2
Vacuum Degasifier Building		Not in scope of LRA
Warehouse No. 1 through Warehouse No. 7		Not in scope of LRA

Notes:

'X' – Denotes structure is within the scope of license renewal.

1. The Borated Water Storage Tank (T3) sits on a slab that is part of the Auxiliary Building.
2. Includes associated structural components and commodities (i.e., supports, spent fuel pool) within the scope of license renewal.
3. Category 1 portions.
4. Limited areas containing 10CFR50.48-required fire barriers are in-scope.

2.3 MECHANICAL SYSTEMS SCOPING AND SCREENING RESULTS

2.3.1 Reactor Coolant System Mechanical Components

2.3.1.1 Description of the Process to Identify Reactor Coolant System Components Subject to Aging Management Review

The determination of mechanical systems within the scope of license renewal is made by initially identifying ANO-1 mechanical systems and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10CFR54.4. This process is described in Section 2.1 and the results of the mechanical systems review are contained in Section 2.2. Section 2.3.1 contains the information required by 10CFR54.21(a)(1) and 10CFR54.21(a)(2) for the ANO-1 RCS components that are subject to aging management review for license renewal.

The RCS is within the scope of license renewal because it is relied upon to remain functional during and following design basis events, and it is relied upon in safety analyses and plant evaluations to perform a function that demonstrates compliance with the NRC regulations for fire protection, environmental qualification, anticipated transients without scram, and station blackout. RCS components are designed to maintain functional integrity during seismic events.

The method used to determine the RCS structures and components subject to aging management review is consistent with the guidance in NEI 95-10 (Reference 2.3-1). The list of those RCS components that are subject to aging management review was made by reviewing ANO-1 flow diagrams for the RCS and marking the ANO-1 ISI Class 1 boundary. For ANO-1, the Class 1 ISI boundary and Class 1 design boundary are equivalent. Evaluation boundaries for the portions of the RCS within the scope of license renewal are shown on the flow diagrams listed in Table 2.3-1.

The RCS mechanical components subject to aging management review were identified by reviewing the following documentation: ANO-1 piping and instrumentation diagrams, SAR Chapters 3.0, 4.0, and 5.0, and ANO-1 Upper Level Documents. RCS mechanical components subject to aging management review include B&W designed vessels (i.e., reactor vessel and control rod drive mechanism pressure boundary, pressurizer, and once-through steam generators) and reactor vessel internals, reactor coolant pumps, and Class 1 piping and valves.

ANO-1 Class 1 piping includes B&W-supplied piping (i.e., main coolant, pressurizer surge, pressurizer spray, and incore monitoring system) and Bechtel-supplied piping (i.e., vents, drains, instrumentation lines, and Class 1 portions of ancillary systems attached to the B&W scope of supply and the reactor coolant pumps). Ancillary systems include decay heat/low pressure injection, core flood, high pressure injection/makeup and purification, and reactor building isolation. Within the Bechtel-supplied piping attached to the B&W scope of supply, the Class 1 RCS boundary extends to the second isolation valve with the exception of the pressurizer code safety valves.

Other RCS components within the scope of license renewal include non-Class 1 instrumentation tubing, piping, valves, and the letdown coolers.

The B&W-supplied vessels were designed in accordance with ASME Section III Class A (Reference 2.3-2), 1965 Edition, with Addenda through the Summer of 1967. Reactor coolant pumps were designed in accordance with ASME Section III, 1968 Edition, with no Addenda; however, the pumps were not code stamped. The RCS piping supplied by B&W and Bechtel was designed to Nuclear Piping Code USAS B31.7 (Reference 2.3-3), dated February 1968 and as corrected for Errata under date of June 1968. Subsequent to the original design, modifications to the RCS can be made utilizing later appropriate ASME Section III Code sections if they have been reconciled. The design of the reactor vessel internals meets the intent of ASME Section III with qualification of the design accomplished through a combination of analysis and testing. The letdown coolers were designed in accordance with ASME Section III Class C for the tube side and ASME Section VIII (Reference 2.3-4) for the shell side.

Component intended functions have been determined based on a review of the ANO-1 SAR and design documents. Components within the boundary of the RCS that perform their intended functions without moving parts or without a change in configuration or properties are listed in Table 3.2-1, along with the intended functions they must maintain. Entergy Operations actively participated in a BWOG effort that developed a series of topical reports whose purpose was to demonstrate that the aging effects for RCS components are adequately managed for the period of extended operation. The following is a list of the BWOG topical reports applicable to the RCS at ANO-1 that have been approved by the NRC:

- BAW-2243A, Reactor Coolant System Piping (Reference 2.3-5)
- BAW-2244A, Pressurizer (Reference 2.3-6)
- BAW-2251A, Reactor Vessel (Reference 2.3-7)
- BAW-2248A, Reactor Vessel Internals (Reference 2.3-8)

NRC approved reports may be incorporated by reference pursuant to 10CFR54.17(e) provided the conditions of approval contained in the safety evaluation of the specific report are met. These reports have been incorporated by reference into the ANO-1 LRA as discussed in Section 2.3.1.2. Each of the components of the RCS that are subject to aging management review are described in Sections 2.3.1.3 through 2.3.1.9.

2.3.1.2 Process to Incorporate Approved BWOG Topical Reports by Reference

Entergy Operations used the following process to incorporate approved BWOG topical reports by reference into the ANO-1 LRA.

(1) *Comparison of the component intended functions for the RCS components under review.* The ANO-1-specific component screening review first identifies the component intended functions and then compares these functions to those identified in the generic BWOG topical reports. Differences are noted and justification for the variances provided.

(2) *Identification of the items that are subject to aging management review.* ANO-1 drawings and pertinent design and field change data are reviewed. The process establishes the full extent to which the scope of the generic BWOG topical reports bound the ANO-1 RCS components.

(3) Identification of the applicable aging effects. An independent assessment of the applicable aging effects is performed by reviewing plant operating environment, operating stresses (qualitative), and plant-specific operating experience. This reveals potential aging effects not identified in the generic BWOG topical reports. Aging effects for items that are determined to be subject to aging management review that were not identified in the generic BWOG topical reports are evaluated.

The results of steps (1) and (2) are provided in Sections 2.3.1.3 through 2.3.1.9, while the results of step (3) are provided in Section 3.2.

2.3.1.3 Reactor Coolant System Piping

For ANO-1, the following components are within the reactor coolant pressure boundary: reactor vessel, once-through steam generators (primary side), pressurizer, reactor coolant pump, main coolant piping and portions of systems attached to these components. The attached systems that contain Class 1 components include the core flood system, makeup/high pressure injection system, and decay heat/low pressure injection system. In addition, vents, drains, and instrumentation lines also contain Class 1 components. RCS piping includes piping (including fittings, branch connections, safe ends, and thermal sleeves), pressure retaining parts of RCS valves, and bolted closures and connections. Additional descriptions of the RCS piping are contained in SAR Section 4.2.2.4.

Non-Class 1 portions of the systems attached to the RCS are discussed in the following sections.

Section 2.3.2.1-Core Flood

Section 2.3.2.2-Low Pressure Injection/Decay Heat

Section 2.3.2.3-High Pressure Injection/Makeup and Purification

Section 2.3.2.7-Reactor Building Isolation

As noted in Section 2.3.1.1, BWOG topical report BAW-2243A has been approved by the NRC for use by applicants for a renewed operating license. As a result of NRC review of this report, several renewal applicant action items were identified. These action items are described in Section 4.1 of the safety evaluation issued by the NRC regarding BAW-2243A. The ANO-1 specific responses to these action items relevant to the identification of RCS piping components subject to aging management review are provided in Table 2.3-2.

As summarized in Section 2.3.1.1, Entergy Operations participated in the development of BAW-2243A by providing ANO-1 specific design and operational information.

Entergy Operations has reviewed the current design and operation of the ANO-1 RCS piping using the process described in Section 2.3.1.2 and confirms that the ANO-1 Class 1 piping is bounded by the description of Class 1 piping contained in BAW-2243A with regard to materials and operating environment. ANO-1 specific findings regarding RCS piping are contained in the following paragraphs.

The fast response RTE connections include a thermowell mounted within the mounting boss. The thermowell, which is constructed from Type 304 austenitic stainless steel, was omitted from the scope of BAW-2243A. In addition, the evaluation boundary in BAW-2243A did not include non-Class 1 instrumentation tubing that connects the second isolation valve to the instrumentation. These items are part of the RCS pressure boundary at ANO-1, are constructed from austenitic stainless steel, and are evaluated in Section 3.2. Other items that were not within the scope of BAW-2243A include the letdown coolers and reactor vessel leakage monitoring pipes that are connected to the reactor vessel.

<u>Letdown Coolers</u>

The letdown coolers are not within the scope of BAW-2243A but are subject to aging management review at ANO-1. The letdown coolers are heliflow shell and tube heat exchangers with spiral Type 304 stainless steel tubes and manifolds, carbon steel casing shells, and carbon steel casing end plates. The tube side was designed in accordance with ASME Section III, Class C, and the shell side was designed in accordance with ASME Section VIII. The primary water enters the tubes at approximately 555°F during normal plant operation and is cooled to approximately 120°F by intermediate cooling water (treated water) flowing through the shell. The intermediate cooling water enters at approximately 95°F and exits at less than 175°F. Both coolers are in service during normal plant operation with a relatively constant intermediate cooling water flow rate. The total letdown flow rate that is split between the coolers is manually varied anywhere between 45 and 140 gpm as required for RCS inventory control. The letdown flow through the coolers may be manually or automatically terminated.

<u>Reactor Vessel Leakage Monitoring Piping</u>

The 1-inch, schedule 160, reactor vessel leakage monitoring system piping attached to the reactor vessel is Class 3 at ANO-1. The lines do not support the RCS pressure boundary and were not in the scope of BAW-2243A (RCS Piping Report) or BAW-2251A (Reactor Vessel Report). If the reactor vessel closure flange O-rings fail and RCS fluid is introduced into the monitoring piping, leak flow would be limited since the 1/2-inch diameter hole in the vessel flange, which connects the region between the O-rings to the monitoring pipe, is less than the ID of the monitoring pipe. Therefore, the reactor vessel leakage monitoring piping is not subject to aging management review since the piping does not directly support the RCS pressure boundary.

2.3.1.4 Pressurizer

The pressurizer is a vertical cylindrical vessel with a surge line penetration connecting the surge line to the hot leg piping. The pressurizer contains electric heaters in its lower section and a water spray nozzle in its upper section. Since sources of heat in the RCS are interconnected by piping with no intervening isolation valves, relief protection is provided on the pressurizer. Overpressure protection consists of two code safety valves and one power operated relief valve.

Piping attached to the pressurizer is Class 1 up to and including the second isolation valve (with the exception of the pressurizer code safety valve) and is discussed in Section 2.3.1.3. Additional descriptions of the ANO-1 pressurizer are contained in SAR Section 4.2.2.3 and BAW-2244A. The pressurizer is shown on SAR Figure 4-14.

As noted previously in Section 2.3.1.1, BWOG topical report BAW-2244A has been approved by the NRC for use by applicants for a renewed operating license. Entergy Operations has reviewed the current design and operation of the ANO-1 pressurizer using the process described in Section 2.3.1.2 and has confirmed that the ANO-1 pressurizer is bounded by the description contained in BAW-2244A. As a result of NRC review of BAW-2244A, several renewal applicant action items were identified. These Action Items are described in Section 4.1 of the safety evaluation issued by the NRC concerning BAW-2244A (Reference 2.3-6). The ANO-1 specific responses to the renewal applicant action items relevant to the pressurizer are provided in Table 2.3-3.

2.3.1.5 Reactor Vessel

The reactor vessel consists of the cylindrical vessel shell, lower vessel head, closure head, nozzles, interior attachments, and associated pressure retaining bolting. Coolant enters the reactor through the inlet nozzles, passes down through the annulus between the thermal shield and vessel inside wall, reverses at the lower head, passes up through the core, turns around through the plenum assembly, and leaves the reactor vessel through the outlet nozzles. The ANO-1 reactor vessel is shown on SAR Figure 4-4.

The reactor vessel has two outlet nozzles through which the coolant is transported to the steam generators and four inlet nozzles, through which coolant enters the reactor vessel from the discharge of the reactor coolant pumps. Two smaller nozzles located between the inlet nozzles serve as inlets for decay heat removal and emergency core cooling water injection. Instrumentation nozzles penetrate the lower vessel head. Piping attached to the reactor vessel is discussed in BAW-2251A (Reference 2.3-7) and covered in Section 2.3.1.3. The reactor vessel support skirt and control rod drive service structure are addressed in Section 2.4.2.1.

Control rod drive mechanisms are attached to flanged nozzles, which penetrate the closure head. The active portions of the control rod drive mechanisms are not within the scope of license renewal; however, the control rod drive motor tube assemblies and closure insert and vent assemblies are subject to aging management review and are discussed in Section 2.3.1.9. One of the ANO-1 CRDMs was removed to install a reactor vessel level monitoring probe. The reactor vessel level monitoring probe is discussed in Section 2.3.1.6. Additional descriptions of the reactor vessel are contained in SAR Section 4.2.2.1 and BAW-2251A.

As noted previously in Section 2.3.1.1, BWOG topical report BAW-2251A has been approved by the NRC for use by applicants for a renewed operating license. Entergy Operations has reviewed the current design and operation of the reactor vessel using the process described in Section 2.3.1.2 and has confirmed that the ANO-1 reactor vessel is bounded by the description contained in BAW-2251A.

As a result of NRC review of BAW-2251A, several renewal applicant action items were identified. These action items are described in Section 4.1 of the safety evaluation issued by the NRC concerning BAW-2251A (Reference 2.3-7). The ANO-1 specific responses to the renewal applicant action items relevant to the reactor vessel are provided in Table 2.3-4.

2.3.1.6 Reactor Vessel Internals

The reactor vessel internals consist of two structural subassemblies located within the reactor vessel. These two subassemblies of the internals are the plenum assembly and the core support assembly. The reactor vessel internals can be removed during refueling outages when necessary. Descriptions of the reactor vessel internals for ANO-1 are contained in BAW-2248A and in SAR Section 3.2.4.1. The reactor vessel internals are shown on SAR Figure 3-59.

Entergy Operations has reviewed the current design and operation of the ANO-1 reactor vessel internals using the process described in Sections 2.3.1.1 and 2.3.1.2 and has determined that the ANO-1 internals have three additional intended functions that were not listed in BAW-2248A:

- supporting the reactor vessel level monitoring probe,
- providing gamma and neutron shielding, and
- providing support for the surveillance specimen assemblies in the annulus between the thermal shield and the reactor vessel wall.

One of the ANO-1 CRDMs was removed and the control rod guide assembly in the plenum was modified to accept the reactor vessel level monitoring probe. Support of the monitoring probe is an additional intended function of the reactor vessel internals. The items that support the reactor vessel level monitoring probe are fabricated from Type 304L austenitic stainless steel and are evaluated in Section 3.2.5.

The thermal shield, thermal shield upper restraint and associated bolting, which are all fabricated from austenitic stainless steel, support the intended function "provide gamma and neutron shielding." These items are subject to aging management review and are evaluated in Section 3.2.5.

In addition, portions of the ANO-1 surveillance specimen holder tubes are attached to the internals. Although all the specimens have been removed, portions of the shroud tube and the supports that are bolted to the core support shield remain. These items only have the function of remaining secured to prevent loose parts in the RCS. This function will be considered applicable to the remaining portions of the surveillance specimen holder tubes. These items are evaluated in Section 3.2.5.

As a result of NRC review of BAW-2248A, several renewal applicant action items were identified. The BAW-2248A applicant action items are described on Section 4.1 of the safety evaluation issued by the NRC concerning BAW-2248A (Reference 2.3-8). The

ANO-1 specific responses to the renewal applicant action items relevant to the reactor vessel internals are provided in Table 2.3-5.

2.3.1.7 Once-Through Steam Generators

ANO-1 has two once-through steam generators. Each is a vertical, straight-tube, once-through, counterflow, shell-and-tube heat exchanger with shell-side boiling. The steam generator consists of upper and lower hemispherical heads welded to tubesheets that are separated by a shell assembly. Over 15,000 straight Alloy 600 tubes are held in alignment by fifteen tube support plates. The once-through steam generator is shown on SAR Figure 4-5.

Primary coolant from the reactor enters the steam generator through a single inlet nozzle in the top of the upper head. Coolant flows downward through the straight parallel tubes, is cooled by the secondary coolant on the shell side, and then exits through two outlet nozzles in the lower head. Secondary coolant enters through a ring of ports that penetrate the shell approximately midway up the shell assembly. The feedwater travels downward through an annulus between the lower baffle and the shell. Near the lower tubesheet, the feedwater turns inward and then flows upward around the tubes and through the tube support plates. As the feedwater absorbs heat from the primary coolant, it boils and then becomes superheated. The dry steam exits the steam generator through two steam outlet nozzles just above the feedwater inlet ports.

The intended functions of the once-through steam generators include maintaining primary pressure boundary, maintaining secondary pressure boundary, providing heat transfer from the primary fluid to the secondary fluid, and reactor building isolation. Once-through steam generator items that are subject to aging management review include the hemispherical heads, secondary shell, tubes, plugs, mechanical sleeves, tubesheets, primary nozzles, primary manway and inspection port assemblies, main and auxiliary feedwater nozzles, main and auxiliary feedwater header and riser piping, steam outlet nozzles, instrumentation nozzles, temperature sensing connections, drain nozzles, secondary manway and inspection port covers, associated pressure retaining bolting, and integral attachments inspected in accordance with ASME Section XI (Reference 2.3-9), Subsections IWB and IWC. Class 1 RCS piping attached to the primary once-through steam generator nozzles, including the welded joints, is addressed in Section 2.3.1.3. Secondary piping attached to the once-through steam generator nozzles, including the main and auxiliary feedwater headers and riser piping, is addressed in Section 2.3.4.2. The steam generator supports are addressed in Section 2.4.2.

Once-through steam generator items that do not support an intended function and that are not subject to aging management review include weld deposit pads on the external shell of the generator that are used for insulation supports, shell thermocouples, and grounding lugs; an internal support ring that is attached to the inside shell of the secondary side, secondary internal baffles, support plates, variable orifice plate, and tube stabilizers; and gaskets used in bolted connections at manways inspection ports, and main and auxiliary feedwater inlet piping.

Once-through steam generator items fabricated from low-alloy steel include the hemispherical heads, transition ring, tubesheets, and pressure retaining bolting.

Items fabricated from carbon steel include primary inlet and exit nozzles, secondary shell, secondary outlet nozzles, main and auxiliary feedwater header and riser piping, primary and secondary manway covers, primary and secondary inspection port covers, secondary vent nozzles, drain nozzles, level sensing nozzles, and main and auxiliary feedwater nozzles. Items fabricated from Alloy 600 include the primary drain nozzle, nozzle dam support rings, tubes, plugs, sleeves, and secondary temperature sensing connections. The once-through steam generators were designed as Class A vessels in accordance with ASME Section III, 1965 Edition, with Addenda through Summer of 1967, (Reference 2.3-2)

2.3.1.8 Reactor Coolant Pumps

The reactor coolant pumps propel the reactor coolant through the reactor core, piping, and steam generators. The four reactor coolant pumps are required during normal full power operation. The four reactor coolant pumps installed at ANO-1 are Byron-Jackson pumps. The reactor coolant pumps were designed, fabricated, tested, and inspected as Class A vessels in accordance with ASME Section III 1968 Edition. The RCPs were not code stamped.

The intended function of the reactor coolant pumps is to maintain the RCS pressure boundary. The reactor coolant pump items that support the intended function and are subject to aging management review include the casing, cover, integral seal injection heat exchangers, and pressure-retaining bolting. Non-Class 1 piping, instrumentation, and other components attached to the reactor coolant pump are addressed in Section 2.3.2. Class 1 piping connected to the pump, including the welded joints is discussed in Section 2.3.1.3. The portion of the reactor coolant pump rotating element above the pump coupling, the electric motor, and the flywheel are not subject to aging management review in accordance with 10CFR54.21(a)(1).

The reactor coolant pump casings include not only the casings themselves, but also the bolted closures and connections. These are constructed of stainless steel, except for the pressure retaining bolting which is fabricated from low-alloy steel. The upper and lower halves of the Byron-Jackson pump casings are cast austenitic stainless steel.

The pump cover is a generic term used to describe the pressure-retaining closure to the pump casing. The cast austenitic stainless steel cover serves as a housing for the mechanical seal, radial bearing, thermal barrier, and recirculating impeller. The cover is clamped between the carbon steel driver mount and the stainless steel pump casing.

Bolting used to secure the cover to the case includes cover-to-case studs and nuts, which are fabricated from low-alloy steel. Bolting used to secure the seal housing and/or seal glands to the cover includes studs and nuts. These bolting materials are less than two inches in diameter and are fabricated from low-alloy steel.

Each reactor coolant pump is supported by the cold leg piping during all modes of operation. The weight of each reactor coolant pump motor is supported by two vertical constant load supports, which are addressed in Section 2.4.2.1. Additional descriptions of the ANO-1 reactor coolant pumps are contained in SAR Section 4.2.2.5. SAR Figure 4-7 is a drawing of the ANO-1 RCP design.

2.3.1.9 Control Rod Drive Mechanism Pressure Boundary

Control rod drive mechanism motor tube assemblies, closure insert assemblies, and vent assemblies provide the reactor coolant pressure boundary around the control rod drive mechanisms. During normal operation, the control rod drive mechanism motor tube assemblies are filled with borated reactor coolant at the system operating pressure. Thermal barriers in the lower motor tube mechanism and the control rod drive mechanism cooling system maintain the temperatures in the housings below system temperature.

Control rod drive mechanism motor tube assemblies were designed, fabricated, tested, and inspected in accordance with ASME Section III 1965 Edition and Summer 1967 Addendum. The material of construction is stainless steel or Alloy 82/182 clad low-alloy steel.

Two different designs of control rod drive mechanisms are currently in use at ANO-1, Type B and Type C. The control rod drive mechanisms themselves are active and not subject to aging management review for license renewal. The CRDM items subject to aging management review include the motor tube assemblies, closure insert and vent assemblies, associated bolting, and the Reactor Vessel Level Monitoring System adapter flange assembly.

2.3.2 Engineered Safeguards

ANO-1 refers to the engineered safety features as the engineered safeguards. Engineered safeguards consist of systems and components designed to function under accident conditions to minimize the severity of an accident or to mitigate the consequences of an accident. In the event of a loss of coolant accident, the ES provide emergency coolant to assure structural integrity of the core, to maintain the integrity of the reactor building, and to reduce the concentration of fission products expelled to the reactor building atmosphere. The engineered safeguards are described in SAR Chapter 6.

The following systems are included in this section:

- Core Flood
- Low Pressure Injection/Decay Heat
- High Pressure Injection/Makeup and Purification
- Reactor Building Spray
- Reactor Building Cooling and Purge (including reactor building heating and ventilation and portions of reactor building purge)
- Sodium Hydroxide (including chemical addition)
- Reactor Building Isolation
- Hydrogen Control (including hydrogen purge and hydrogen recombiners)

Scoping drawings, consisting of the piping and instrumentation diagrams for the ES systems, are listed in Table 2.3-6, and are provided as attachments to 1CAN010002 (Reference 2.3-10). These drawings have been highlighted to show the portions of the ES systems that are within the scope of license renewal. The boundaries indicated on the drawings are primarily based on the system designations in the component database. The use of the component database in conjunction with the system P&IDs assures that duplicate reviews and omission of components do not occur at the interface boundaries. The mechanical components and their intended functions for the ES systems are identified in Table 3.3-1 through Table 3.3-8.

2.3.2.1 Core Flood

The core flood system is described in SAR Sections 6.1.2.1.3 and 6.1.3.3. The safety function of the core flood system is to provide core cooling after intermediate and large break LOCAs. The core flood system components within the scope of license renewal and subject to aging management review include two core flood tanks and piping and components up to the reactor coolant system boundary. The intended function within the scope of license renewal is to maintain system pressure boundary integrity.

2.3.2.2 Low Pressure Injection/Decay Heat

The low pressure injection system is described in SAR Sections 6.1.3.2 and 6.1.2.1.2 while the decay heat system is described in SAR Section 9.5. The LPI/DH system is a dual-purpose system. This system operates as the DH system to remove decay heat from the core and sensible heat from the RCS during the latter stages of cooldown. The LPI system injects borated water into the reactor vessel to cool the core in the event of a LOCA.

The LPI system has the following safety functions.

- Inject borated water from the BWST during postulated large break LOCA
- Provide long term cooling following a LOCA by recirculating injection water from the reactor building sump
- Supply recirculated water from the reactor building sump to the suction of the high pressure injection pumps if RCS pressure is too high to allow the LPI pumps to function
- Supply injection water from the BWST to the DH/LPI pumps as well as the high pressure injection and the reactor building spray pumps (the BWST floods the reactor building basement to a level that will allow for recirculation from the reactor building sump under accident conditions)
- Provide water that is free of entrained air from the screened reactor building sump, when the BWST is depleted.

The decay heat system is credited in the 10CFR50.48 analysis with the capability of attaining cold shutdown. Therefore, the DH system has a function to remove decay heat from the reactor core and sensible heat from the RCS during the latter stages of cooldown such that fuel design limits and design conditions of the RCS pressure boundary are not exceeded. The DH system also supports the following functions.

- Circulating reactor coolant to prevent boron stratification and to minimize the effects of a boron dilution event
- Providing an alternate supply of borated water from the BWST for volume contraction during cooldown to cold shutdown
- Providing cooling, inventory addition, and instrumentation for loss of decay heat removal events

The following LPI/DH components are within the scope of license renewal and subject to aging management.

- The decay heat system piping that passes through the reactor building penetrations including the injection lines, the drop line, the pressurizer auxiliary spray line and the emergency sump lines (these portions of the system perform a reactor building isolation function and are within the scope of license renewal)
- The DH drop line valves, the DH coolers, the DH cooler isolation valves, and the decay heat pumps

- The BWST, the BWST supply header, and the injection lines up to the outboard RCS pressure boundary valve of the low-pressure injection lines, as well as the suction supply piping to the high pressure injection system
- The piping and components from the reactor building sump, including some piping and components that are part of the PASS system, which is used for post LOCA sump sampling (The sump screens and the vortex breakers are reviewed in Section 2.3.3.4.)
- The oil side of the LPI pump lube oil coolers (the service water side of the coolers is evaluated in Section 2.3.3.10).

The intended function within the scope of license renewal is to maintain the pressure boundary integrity. For the heat exchangers, heat transfer is a passive function within the scope of license renewal.

2.3.2.3 High Pressure Injection/Makeup and Purification

The safety function of the high pressure injection system is to provide high pressure injection into the RCS during emergency conditions. This system is normally operated as part of the MUP system. During normal operations, the MUP system performs various functions in support of the RCS. The HPI system is described in SAR Sections 6.1.2.1.1 and 6.1.3, while the MUP system is described in SAR Section 9.1.

The HPI/MUP system has the following safety functions.

- Inject borated water from the BWST during postulated accidents such as the small break LOCA
- Provide long term cooling following small break LOCAs by recirculating injection water from the reactor building sump

The HPI/MUP system is credited in the 10CFR50.48 analysis with the capability for RCS makeup and pressure control. Some of the system valves must remain closed to prevent a direct RCS leak path in the event of a fire. The HPI/MUP system also supports the following functions.

- Provide inventory to the RCS during operational transients such as reactor trips and overcooling events
- Provide a backup inventory supply to the RCS during a loss of decay heat removal event
- Provide core cooling following a total loss of feedwater event via feed and bleed cooling of the RCS
- Provide an auxiliary means to spray the pressurizer steam space when normal spray is not available

The following HPI/MUP components are within the scope of license renewal and subject to aging management.

- The seven mechanical reactor building penetrations necessary for meeting reactor building isolation requirements

- The Class 1 RCS pressure boundary that extends to the second isolation valve off of the RCS (For the letdown line, this is downstream of the letdown coolers. The letdown coolers and the Class 1 valves are reviewed in Section 2.3.1.3.)
- The HPI piping from the BWST supply header up to the outboard RCS pressure boundary valve of the injection lines, and all portions of the system needed to support high pressure injection, including the suction supply from the low pressure injection system
- The oil-side of the HPI pump oil coolers (the service water side of the coolers is evaluated in Section 2.3.3.10.)

The intended function within the scope of license renewal is maintaining system pressure boundary integrity. For the heat exchangers, heat transfer is a passive function within the scope of license renewal.

2.3.2.4 Reactor Building Spray

The reactor building spray system is described in SAR Section 6.2. The safety function of the RBS system is to reduce reactor building pressure following accidents that pressurize the reactor building. This reduction in pressure reduces the driving force for leakage of radioactive materials from the reactor building following a LOCA. The RBS system also reduces the concentration of fission products in the reactor building atmosphere following a LOCA.

The components within the scope of license renewal and subject to aging management review consist of both trains of pumps and supporting equipment (lube oil coolers and seal water cyclone separators), piping, valves, and spray headers. The interfacing systems that form part of the RBS system pressure boundary are also included. This includes the interfacing valves from the "spared in place" sodium thiosulfate tank, the interfaces with the service air system, and the vents and drains off the RBS pump casings. The sodium hydroxide system is covered in Section 2.3.2.6.

The intended function within the scope of license renewal is to maintain RBS system pressure boundary integrity. For the bearing heat exchangers, heat transfer is a passive function within the scope of license renewal.

2.3.2.5 Reactor Building Cooling and Purge

The reactor building cooling and purge system is described in SAR Section 5.2.6. The safety function of the reactor building cooling system is to reduce the post-accident pressure and temperature in the reactor building and provide mixing of the reactor building atmosphere following a loss of coolant accident. During normal plant operation, the system must maintain the reactor building temperature below the maximum allowed for the equipment and below the accident analyses initial temperature assumptions. The reactor building purge has no safety function; however, the penetrations in this system must maintain reactor building integrity under accident conditions.

The following components are within the scope of license renewal and subject to aging management review.

- The four safety-related reactor building coolers
- The service water cooling coils, the fan/cooler housings and the discharge duct work, including the duct relief valves that prevent damage to the ductwork during a rapid building pressurization
- The reactor building isolation valves and piping at the two penetrations in the reactor building purge system

The intended function within the scope of license renewal is to maintain integrity. For the heat exchangers, heat transfer is a passive function within the scope of license renewal.

2.3.2.6 Sodium Hydroxide

The safety function of the sodium hydroxide system is to provide a solution of sodium hydroxide to the ECCS suction headers. The increased pH improves iodine absorption and retention in the water, thereby minimizing the gaseous iodine and the offsite dose following a LOCA. The sodium hydroxide system is described in SAR Section 6.2. The components within the scope of license renewal and subject to aging management review are the sodium hydroxide tank and associated piping and components from the tank to the ECCS suction headers that are required to maintain the pressure boundary. The intended function within the scope of license renewal is to maintain the system pressure boundary integrity.

2.3.2.7 Reactor Building Isolation

The reactor building isolation system is described in SAR Section 5.2.5. A safety function of the reactor building isolation system is to allow passage of required fluids, materials, personnel, electrical signals, and electrical power across the reactor building boundary. In addition, the reactor building isolation system seals penetrations that are not required for operation to provide a fission product barrier between the inside of the reactor building and the outside environment. This capability is also required for the nonsafety-related systems that penetrate the reactor building. Therefore, the penetrations have a reactor building isolation function in addition to their system function.

The components within the scope of license renewal and subject to aging management review are the 20 mechanical penetration components and piping that are not included in other sections of the ANO-1 LRA. These penetrations involve the following.

- Intermediate cooling water, nitrogen, breathing air, plant heating, and gaseous radwaste
- Core flood: tank sampling and makeup and nitrogen pressurization
- Sampling system: steam generator secondary sampling and quench tank sampling
- Condensate storage and transfer: condensate transfer supply to quench tank
- Liquid radwaste: quench tank drain

- Heater vents system: steam generator secondary drains
- Integrated leak rate test connection

The intended function within the scope of license renewal is to maintain system pressure boundary integrity.

2.3.2.8 Hydrogen Control

The hydrogen control system is described in SAR Section 6.6. The safety function of the hydrogen control system is to provide a direct reading of the hydrogen concentration in the reactor building using the hydrogen analyzer system and to reduce the hydrogen concentration following a LOCA using the hydrogen recombiner system.

The hydrogen control system components within the scope of license renewal and subject to aging management review are the penetrations, the passive mechanical components of the hydrogen samplers and the piping to and from the hydrogen samplers. The piping to the analyzers uses a portion of the hydrogen purge system, and one of the boundary valves is in the gas collection header system. The passive mechanical components of the hydrogen recombiners are also in the scope of license renewal and subject to aging management review. The control power cabinets in the penetration room and the passive electrical components of the recombiners are addressed in Section 2.5.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the heat exchangers, heat transfer is a passive function within the scope of license renewal.

2.3.3 Auxiliary Systems

The following systems are included in this section.

- Spent fuel
- Fire protection
- Emergency diesel generator
- Auxiliary building sump and reactor building drains
- Alternate AC diesel generator
- Halon
- Fuel oil
- Instrument air
- Chilled water
- Service water
- Penetration room ventilation
- Auxiliary building heating and ventilation
- Control room ventilation

Scoping drawings, consisting of the piping and instrumentation diagrams for the auxiliary systems, are listed in Table 2.3-7, and are provided as attachments to 1CAN010002 (Reference 2.3-10). These drawings have been highlighted to show the portions of the auxiliary systems within the scope of license renewal. The boundaries indicated on the drawings are primarily based on the system designations in the component database. The use of the component database in conjunction with the system P&IDs assures that duplicate reviews and omission of components do not occur at the interface boundaries. The mechanical components and their intended functions for the systems in this section are identified in Table 3.4-1 through Table 3.4-13.

2.3.3.1 Spent Fuel

The spent fuel system is described in SAR Section 9.4.1. The safety functions of the spent fuel system are to maintain an adequate water level in the pool for cooling and shielding and to maintain the subcritical margin. The emergency makeup supply to the spent fuel pool from the service water system does not utilize the spent fuel pool cooling system piping and is therefore, reviewed with the service water system in Section 2.3.3.10.

The spent fuel pool stainless steel liner and the spent fuel pool gates are in the scope of license renewal and subject to aging management review. The liner protects the concrete walls from direct contact with the borated water and maintains the leak tightness of the pool.

The intended function for the spent fuel pool liner within the scope of license renewal is to maintain the system pressure boundary integrity.

Other spent fuel system components within the scope of license renewal and subject to aging management review are the following.

- The spent fuel racks, which support the spent fuel assemblies
- A mechanical reactor building penetration used for filling and draining of the fuel transfer canal (The pipe and valves are addressed in this section, while the penetration assembly is addressed in Section 2.4.1.1)
- The fuel transfer tube, which is a reactor building penetration (A blind flange is installed on the tube in the reactor building to ensure reactor building integrity is maintained during power operation. The fuel transfer tube and the blind flange are addressed in this section, while the penetration assembly is addressed in Section 2.4.1.1)
- The Boraflex neutron absorber material, which helps to maintain the subcritical margin (Boraflex is addressed in Section 4.7)

2.3.3.2 Fire Protection

The fire protection system is described in SAR Section 9.8.1. The safety function of the fire protection system is to minimize the effects of fires on structures, systems, and components important to safety as required by 10CFR Part 50 Appendix A, General Design Criteria 3. In accordance with 10CFR Part 54, the components required for compliance with 10CFR50.48 are in the scope of license renewal.

The following fire protection system components are within the scope of license renewal and subject to aging management review.

- The electric motor driven fire pump
- The diesel driven fire pump, including the engine gearbox oil cooler, the jacket water heat exchanger and the lube oil cooler (The fuel oil portions of the system are covered in Section 2.3.3.7.)
- The fire water distribution system including the portion of the outside loop, hose stations, standpipes, sectional control valves, and isolation valves that are required for protection of safety-related areas (Although the hose stations are included, the hoses are not normally part of the pressure boundary and are therefore outside of the scope of license renewal.)
- Sprinkler systems protecting safety-related areas, including piping, control valves, and sprinkler heads
- Sprinkler systems required to meet 10CFR50.48 requirements, including piping, control valves, and sprinkler heads

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. The diesel fuel pump lube oil coolers also have the passive component function of heat transfer to cool the oil.

2.3.3.3 Emergency Diesel Generator

The emergency diesel generators are described in SAR Section 8.3.1.1.7. The safety function of the EDGs is to supply the engineered safeguards bus loads following a design basis accident. The EDGs are also required to be available following a fire and are considered components required to comply with 10CFR50.48.

The following EDG system components are within the scope of license renewal and subject to aging management review .

- Safety-related portions of the EDG starting air subsystem from the receivers to the EDG assembly
- EDG lubrication subsystem components
- EDG combustion air intake and exhaust subsystem components
- EDG cooling water subsystem components
- The fuel oil system including the EDG fuel oil components will be evaluated in Section 2.3.3.7
- The service water side of the EDG heat exchangers is addressed in Section 2.3.3.10

The intended function within the scope of license renewal is to maintain pressure boundary integrity. Heat transfer is also a function in the scope of license renewal for the heat exchangers.

2.3.3.4 Auxiliary Building Sump and Reactor Building Drains

The ANO-1 auxiliary building sump and reactor building drain systems consist of the floor and equipment drains, piping, valves, sumps and tanks that collect liquids from the reactor building and auxiliary building for processing or disposal.

The following are the safety-related functions of the auxiliary building sump and reactor building drains:

- The reactor building penetrations contain the radioactivity in the reactor building following a LOCA. The penetrations are in the reactor building sump and reactor building drain systems.
- The screens on the reactor building sump and floor drains prevent debris from entering the reactor building sump and interfering with recirculation post LOCA. The screens are in the dirty water drain system.
- The anti-vortex device on the reactor building sump prevents vortexing that could occur under accident conditions when the reactor building is flooded and recirculation of the reactor building water is underway. The anti-vortex device is part of the reactor building sump system.
- The decay heat pump room drains and isolation valves ensure the radioactive liquids that could be present in the decay heat room following a LOCA do not

escape to other portions of the auxiliary building. These drains are in the auxiliary building sump system.

- The reactor coolant pump motor oil leakage collection tanks, piping and valves collect oil leakage from the reactor coolant pump motors in order to reduce the chance of a fire. This function is not safety-related, but is required by 10CFR50.48, and does require pressure boundary integrity to prevent a fire involving leaking oil. These components are part of the reactor coolant system.

The following auxiliary building sump and reactor building drain system components are within the scope of license renewal and subject to aging management review.

- Mechanical components associated with penetrations that are required for reactor building isolation
- Reactor building sump inlet and anti-vortexing screen and the individual screens on the floor drains that drain into the reactor building sump that prevent debris from entering the sump and interfering with recirculation post LOCA. (The concrete sump and the structural steel for the sump including the screen structural steel supports and sump divider plate are evaluated as structural components)
- The valves and piping that isolate the decay heat pump rooms, which are credited as part of the room pressure boundary for offsite dose calculations
- The reactor coolant pump motor oil leakage collection tanks and piping that are specifically required by 10CFR50.48

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity.

2.3.3.5 Alternate AC Diesel Generator

The alternate AC generator is a 4400 kW diesel generator installed in response to the regulatory requirements of 10CFR50.63, "Loss of All Alternating Current Power," to provide backup power in the event of a station blackout at ANO-1 or ANO-2.

The AAC generator system is required by 10CFR50.63, but it does not have a safety-related function. The AAC generator system is credited for providing power during a loss of off-site power concurrent with a loss of the EDGs (i.e., station blackout).

The following AAC generator system components are within the scope of license renewal and subject to aging management.

- Portions of the pressure boundary of the AAC generator starting air subsystem including the receivers to the AAC generator assembly
- The AAC generator combustion air intake and exhaust subsystems
- Components required to maintain the pressure boundary of the AAC generator cooling water subsystem
- Components required to maintain the pressure boundary of the AAC generator lubrication subsystem

- The two engine room exhaust fans that provide the necessary cooling when the engine is in service and the corresponding inlet air dampers
- An exhaust fan that provides the necessary cooling for the switchgear room and the corresponding inlet air damper

The AAC generator building is covered in Section 2.4.6.1

The fuel oil subsystem components are evaluated in Section 2.3.3.7

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the heat exchangers, heat transfer is also a passive function within the scope of license renewal.

2.3.3.6 Halon

The halon system is described in SAR Section 9.8.2. The ANO-1 halon fire system equipment provides fire protection for the ceiling and false floor of the ANO-1 control room as required by 10CFR50.48. Most of the halon system is within the scope of license renewal and subject to aging management review. Specifically, the halon cylinders, actuation valves, pilot piping, manual actuator cylinders and valves, discharge piping, and outlet nozzles are within scope. The passive electrical portions of the system are evaluated in Section 2.5. The bottle racks, supports for the system, ceiling tiles, marinite boards, concrete walls, concrete and false floor components which are required to enclose these areas and allow the effective use of halon, are addressed in Section 2.4.3. The intended function within the scope of license renewal is to maintain the system pressure boundary integrity.

2.3.3.7 Fuel Oil

The fuel oil system is described primarily in SAR Section 8.3.1.1.7.2. The safety function of the fuel oil system is to store and supply fuel oil to the diesel-driven components. The emergency diesel fuel tanks and the EDG day tank have the safety-related function of storing and supplying the emergency diesel generators with fuel oil. The bulk fuel oil storage tank has the nonsafety-related function of storing and supplying fuel oil to nonsafety-related equipment, including the AAC generator and the diesel fire pump day tanks that are in the scope of license renewal. The AAC day tank has the function of storing and supplying fuel oil to the AAC diesel generator in accordance with station blackout commitments. The diesel fire pump day tank function is to store and supply fuel oil to the fire protection diesel as required to satisfy 10CFR50.48 requirements.

The EDG fuel tanks, EDG day tanks, and the safety-related equipment and piping that supports the transfer of fuel to the EDG are within the scope of license renewal and subject to aging management review. Since the bulk fuel oil storage tank has been credited with an extended (4.5 day) supply for the alternate AC generator, the bulk fuel oil storage tank, the AAC diesel generator day tank, and the equipment and piping that supports the transfer of fuel to the AAC diesel generator injectors are included. The diesel driven fire pump day tank and the equipment and piping that supports the transfer of fuel to the diesel fire pump are also included since they are required to satisfy 10CFR50.48.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the heat exchangers, heat transfer is also a passive function within the scope of license renewal.

2.3.3.8 Instrument Air

The instrument air system is described in SAR Section 9.9. The instrument air system is designed to provide a reliable supply of dry, oil-free, compressed air for pneumatic equipment operation. Although the majority of the instrument air system is not safety-related, some safety-related components utilize instrument air for operation of their pneumatic actuators.

The safety-related components that utilize instrument air were reviewed under the scope of license renewal. These components are in the instrument air system as well as other systems. Since many components are designed to fail to the desired post accident condition upon loss of air supply, the integrity of the pressure boundary is not required. However, pressure boundary integrity is required for the following components and thus these components are subject to aging management review.

- The portions of the instrument air system that are part of the reactor building penetration for the instrument air supply to the reactor building, since maintaining the pressure boundary integrity of these components is required for the penetration to perform its intended function
- The instrument air supply to the intermediate cooling water supply valve for the RCP motor air and lube oil coolers (The cooling water supply valve provides reactor building isolation and is provided with a double acting pneumatic cylinder that requires air pressure to reposition the valve. An accumulator is provided in the event of a loss of instrument air. Maintaining the pressure boundary integrity of the accumulator and components between the accumulator and the valve actuator is required.)
- The instrument air supply to the intermediate cooling water supply and return valves for the letdown coolers and RCP seal coolers (These valves provide reactor building isolation and are provided with double acting pneumatic cylinders that require air pressure to reposition the valves. Accumulators are provided in the event of a loss of instrument air, and maintaining the pressure boundary integrity of the accumulators and components between the accumulators and the valve actuators is required.)
- The outside air dampers for the two emergency fan filter units in the control room ventilation system have a function to reposition. High pressure carbon dioxide bottles are provided that can be manually selected as the pneumatic supply for these dampers. Maintaining the pressure boundary integrity is a required function for the carbon dioxide bottles and the portion of the system from the carbon dioxide bottles to the valve actuators

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity for those portions of the system where pressure boundary integrity is required for the component to perform its intended safety function.

2.3.3.9 Chilled Water

The chilled water systems provide chilled water to the cooling coils of a variety of room and area ventilation units. The auxiliary building electrical room emergency chillers are the only safety-related chillers within the scope of license renewal. These chillers have the safety-related function to supply chilled water for emergency cooling to coolers that service the safety-related electrical equipment located in the auxiliary building electrical equipment rooms.

Two emergency chillers, the internal surfaces of the six cooling coils supplied by the chillers, as well as the associated valves and piping are subject to aging management review.

The fan/coil housing assemblies, the external surfaces of the cooling coils, the ductwork and fire dampers in the ductwork are covered in Section 2.3.3.12.

The main chilled water system reactor building penetrations piping and valves, are also included since they provide a safety function of reactor building isolation.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the coolers, heat transfer is also a passive function within the scope of license renewal.

2.3.3.10 Service Water

The service water system is described in SAR Section 9.3. The safety function of the service water system is to transfer heat from safety-related components to an ultimate heat sink, (Lake Dardanelle or the emergency cooling pond). The safety-related service water system provides the emergency supply of water to the emergency feedwater pumps and the spent fuel pool. The service water system is credited in the fire analysis and is required to meet the requirements of 10CFR50.48. If the source of water from Lake Dardanelle is lost, the emergency cooling pond can supply the water to the intake structure for use by the fire pumps.

All passive, long-lived safety-related components and piping in the service water system are within the scope of license renewal and subject to aging management review. In addition, the piping to and from the emergency cooling pond and the sluice gates are included. The intake structure and the emergency cooling pond are evaluated in Sections 2.4.4 and 2.4.5. The individual coolers and heat exchangers supplied by the service water system are reviewed in conjunction with the system being cooled. The service water side of each cooler is evaluated in this section. The interfacing side of each cooler is evaluated in its applicable section. The service water system has four mechanical reactor building penetrations that must meet reactor building isolation requirements. The pipe and valves are reviewed in this section, while the penetration assembly is addressed in Section 2.4.1.1.

The intended function of the service water components and piping within the scope of license renewal is to maintain the service water system pressure boundary integrity. The heat exchangers also have the required function of heat transfer.

2.3.3.11 Penetration Room Ventilation

The penetration room ventilation system is described in SAR Section 6.5.2.1. The safety function of the penetration room ventilation system is to collect and process the radioactivity released to the penetration areas due to post LOCA reactor building leakage to assure the 10CFR Part 100 dose values are not exceeded. The components in the penetration room ventilation system within the scope of license renewal and subject to aging management review include safety-related portions of the system necessary to support emergency operation of the system. This includes the exhaust fans, the pre-filters, the HEPA filters, the adsorber filters, the ductwork and the dampers in the flow path, as well as the dampers that isolate the normal ventilation system. The penetration room floor drain check valves limit backflow into the rooms to aid the penetration room ventilation system in drawing a slight vacuum in these rooms under accident conditions. These drains are in the penetration room ventilation system and are assessed in Section 2.3.3.4.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity

2.3.3.12 Auxiliary Building Heating and Ventilation

The auxiliary building heating and ventilation system is described in SAR Section 9.7.2.1. The safety function of the auxiliary building heating and ventilation system is to provide a suitable environment for those areas of the auxiliary building which contain equipment requiring cooling post accident. Some of the fire dampers in the auxiliary building heating and ventilation system also have the function of closing in the unlikely event of a fire to meet 10CFR50.48 requirements.

The components within the scope of license renewal and subject to aging management review include safety-related portions of the system necessary to support emergency operation of the subsystems. This includes the ductwork, damper bodies, cooler housings, blower housings, and the components that maintain the system flow path for the subsystems that are safety-related. This includes the following:

- emergency diesel generator exhaust fans and inlet dampers
- auxiliary building electrical room unit coolers
- switchgear room unit coolers
- decay heat removal room unit coolers
- makeup pump room coolers

The auxiliary building doors, walls and piping penetrations are evaluated in Section 2.4.3. Although fire dampers are evaluated in Section 2.4.6.2, the fire dampers that form part of the pressure boundary for these systems are addressed in this section.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the coolers (other than makeup pump room coolers), heat transfer is also a passive function within the scope of license renewal.

2.3.3.13 Control Room Ventilation

The control room ventilation system is described in SAR Section 9.7.2.1. The safety-related function of the control room ventilation system is to isolate the control room under accident conditions. The emergency unit coolers, emergency compressor/condensing units and the emergency fan/filter units have a safety-related function of providing a suitable environment for the control room operators and for equipment that requires cooling post accident. There are fire dampers and several temperature elements on the charcoal filters that are credited in the fire analyses, but the majority of the control room ventilation system components are not required by 10CFR50.48.

The components within the scope of license renewal and subject to aging management review include safety-related portions of the system necessary to support the emergency operation of the subsystems. This includes the dampers that isolate the normal ventilation and ductwork, damper bodies, cooler housings, blower housings and other components that maintain the system flow path for the emergency ventilation equipment. The major equipment in the scope of license renewal and subject to aging management review includes:

- normal control room ventilation isolation dampers
- control room emergency unit coolers
- emergency compressor/condensing units
- electrical equipment room 2150 emergency cooling units – included because of their function to maintain the freon pressure boundary
- emergency fan filter units

Fire dampers are covered in Section 2.4.6.2, however the fire dampers that form part of the pressure boundary for the safety-related portions of the control room ventilation system are addressed in this section. The heat exchangers of the emergency compressor/condensing units are exposed to raw water from the service water system and are evaluated in Section 2.3.3.10.

The intended function within the scope of license renewal is to maintain the system pressure boundary integrity. For the coolers, heat transfer is also a passive function within the scope of license renewal.

2.3.4 Steam and Power Conversion Systems

The following systems are included in this section:

- Main Steam
- Main Feedwater
- Emergency Feedwater
- Condensate Storage and Transfer

Scoping drawings, consisting of the P&IDs for the steam and power conversion systems, are listed in Table 2.3-8, and are provided as attachments to 1CAN010002 (Reference 2.3-10). These drawings have been highlighted to show the portions of the steam and power conversion systems within the scope of license renewal. The boundaries indicated on the drawings are primarily based on the system designations in the component database. The use of the component database in conjunction with the system P&IDs assures that duplicate reviews and omission of components do not occur at the interface boundaries. The mechanical component groups and their intended functions for the systems in this section are identified in Table 3.5-1 through Table 3.5-4.

2.3.4.1 Main Steam

The main steam system is described in SAR Section 10.3. The ANO-1 main steam system is primarily a nonsafety-related system, with the majority of the system components outside the scope of license renewal. However, the nonsafety-related small bore piping and components attached to the steam generator shell, which perform a system pressure boundary function, are in scope. This includes valves that are part of the heater vent system. The portion of the main steam system piping that is safety-related is the portion of the piping between the steam generators and the main steam isolation valves, including the steam supply to the EFW turbine, as well as the nitrogen supply to the steam generators.

The main steam system has the safety-related functions of removing heat from the RCS, protecting the RCS and the steam generators from over-pressurization, providing for the isolation of the steam generators during a postulated steam line break, and providing a steam supply to the emergency feedwater turbine.

The components in the main steam system subject to aging management review include the piping, vent, and drain valves from the steam generators up to the main steam isolation valves and EFW turbine steam supply piping. This includes the main steam safety valves, the atmospheric dump and block valves, and the main steam isolation valves. The primary intended function within the scope of license renewal is pressure boundary integrity.

2.3.4.2 Main Feedwater

The main feedwater system is described in SAR Section 10.4.7. The main feedwater system consists of two trains of pumps, feedwater heaters, and the associated piping and valves that supply feedwater to the steam generators to support normal plant operation. The ANO-1 main feedwater system is largely a nonsafety-related system, and therefore, the majority of the system components are outside of the scope of license renewal. The portion of the main feedwater system that is safety-related is the portion of the piping between the main feedwater isolation valves and the steam generators. Other portions of the main feedwater system are nonsafety-related and are outside of the scope of license renewal.

The main feedwater isolation valves isolate the feedwater line during a main steam or a main feedwater line break. The closure of the valves is an active function, but the valve bodies and piping in the safety-related portions of the system must maintain the main feedwater system pressure boundary integrity.

The components in the main feedwater system subject to aging management review include the main feedwater isolation valves and the piping, vent, and drain valves in the piping up to the steam generator ring headers. The primary intended function within the scope of license renewal is pressure boundary integrity.

2.3.4.3 Emergency Feedwater

The ANO-1 emergency feedwater system is described in SAR Section 10.4.8. The EFW system consists of two trains of pumps and the associated piping and valves that supply feedwater to the steam generators if the main feedwater supply is lost. One EFW pump is motor driven and the other is turbine driven. The EFW pumps can take suction from the safety-related condensate storage tank, the nonsafety-related condensate storage tank, the service water system, or the ANO-2 condensate storage tanks. Each EFW pump has discharge piping to both steam generators. The system provides a backup source of feedwater to the steam generators as required to assure that core decay heat and primary system residual heat can be removed. The EFW system removes decay heat until the plant has been cooled and depressurized sufficiently to permit use of the decay heat system. The components in the EFW system subject to aging management review include the EFW discharge piping and valves, the EFW pumps, the safety-related portion of the minimum recirculation lines, and the piping and valves in the discharge up to the EFW headers on the steam generators. The main steam supply valves to the EFW turbine and the steam supply piping downstream of the valves are included in the scope of this review. The EFW headers and nozzles at the steam generators have been included in the scope of the steam generator aging management review.

The primary intended function within the scope of license renewal is pressure boundary integrity. For the heat exchangers in the scope of review, heat transfer is also considered a passive function within the scope of license renewal.

2.3.4.4 Condensate Storage and Transfer System

The ANO-1 condensate storage and transfer system consists of the condensate storage tank, the safety-related condensate storage tank and the system piping and valves to supply water from the condensate storage tanks to the secondary plant systems at ANO-1. The condensate storage and transfer system provides a source of demineralized water to the secondary plant of ANO-1. The safety-related condensate storage tank and the associated piping have the safety significant function of providing the initial (preferred) source of water to the emergency feedwater pumps. These functions are discussed in SAR Section 10.4.8.

The passive mechanical components in the condensate storage and transfer system scope that are required to be included in the scope of license renewal and subject to aging management review include the safety-related condensate storage tank and the piping that maintains the pressure boundary of the condensate storage system up to the emergency feedwater pumps. The primary intended function within the scope of license renewal is pressure boundary integrity.

2.3.5 References for Section 2.3

2.3-1 NEI 95-10, "*Industry Guidelines for Implementing the Requirements of 10CFR Part 54 –The License Renewal Rule*," Revision 0, Nuclear Energy Institute, March 1996.

2.3-2 ASME Boiler and Pressure Vessel Code, Section III, "*Rules for Construction of Nuclear Power Plant Components*," American Society of Mechanical Engineers.

2.3-3 USAS B31.7, "*Nuclear Power Piping,*" USA Standards Institute.

2.3-4 ASME Boiler and Pressure Vessel Code, Section VIII, "*Pressure Vessels*," American Society of Mechanical Engineers.

2.3-5 BAW-2243A, "*Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping*," The BWOG Generic License Renewal Program, June 1996.

2.3-6 BAW-2244A, "*Demonstration of the Management of Aging Effects for the Pressurizer*," The BWOG Generic License Renewal Program, December 1997.

2.3-7 BAW-2251A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel*," The BWOG Generic License Renewal Program, June 1996.

2.3-8 BAW-2248A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel Internals*," The BWOG Generic License Renewal Program, December 1999.

2.3-9 ASME Boiler and Pressure Vessel Code, Section XI, "*Rules for In-Service Inspection of Nuclear Power Plant Components*," American Society of Mechanical Engineers.

2.3-10 1CAN010002, Letter from J. Vandergrift (ANO) to NRC, "*LRA Boundary Drawings*," submitted with the ANO-1 LRA.

Table 2.3-1 Reactor Coolant System P&IDs		
LRP&ID	**Sheet**	**Revision**
LRA-M-230	1	Revision 0
LRA-M-230	2	Revision 0
LRA-M-231	2	Revision 0
LRA-M-232	1	Revision 0
LRA-M-237	1	Revision 0

Table 2.3-2 RCS Piping Applicant Actions Items from Section 4.1 of BAW-2243A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
When incorporating the BWOG topical report in its renewal application, the license renewal applicant is to verify that its plant is bounded by the topical report.	Entergy Operations participated in the development of BAW-2243A by providing ANO-1 specific design and operational information. Entergy Operations has reviewed the current design and operation of the ANO-1 RCS piping using the process described in Section 2.3.1.2. The results of the RCS piping review are reported in Section 2.3.1.3.
Further, the renewal applicant is to commit to programs described as necessary in the report to manage the effects of aging during the period of extended operation on the functionality of the RCS piping components.	Descriptions of these programs are provided in Section 3.2 and Appendix B.
A summary description of these programs is to be provided in the license renewal FSAR supplement in accordance with 10CFR54.21(d).	Summary descriptions of these programs are provided in Appendix A.
Any deviations from the aging management programs described within this report as necessary to manage the effects of aging during the period of extended operation to maintain the functionality of RCS piping components or other information presented in the report, such as materials of construction and edition of the ASME Section XI code (including mandatory appendices), will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10CFR54.21(a)(3).	No deviations from the aging management programs described in BAW-2243A or other information presented in the report have been identified by Entergy Operations.
Further, the BWOG defers the development of details of the inspection of (1) the Alloy 82/182 clad hot leg segment and plant selection for that inspection, and (2) the sample inspection of small bore RCS piping, to the renewal applicant referencing this topical report. The renewal applicant will have to provide details of these two augmented inspection programs in its renewal application for	Descriptions of these programs are provided in Section 3.2 and Appendix B.

Table 2.3-2 RCS Piping Applicant Actions Items from Section 4.1 of BAW-2243A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
staff review and approval.	
The BWOG elected to exclude TLAAs applicable to the RCS piping components from the scope of the topical report and indicated that they will be resolved on a plant-specific basis. Thus, any renewal applicant referencing this report will have to evaluate TLAAs applicable to the RCS piping components in its renewal application in accordance with the requirements in 10CFR54.21(c).	Evaluations of ANO-1 specific TLAAs are provided in Section 4.0.
Additionally, since the staff does not make any finding relative to whether the BWOG report constitutes the complete list of RCS piping components subject to an aging management review or the adequacy of a scoping methodology, individual plant applicants will need to identify and list structures and components subject to an aging management review and a methodology for developing this list as part of their license renewal applications.	A list of RCS components that are subject to aging management review is provided in Section 2.3. The individual components are also listed in ANO-1 specific documents maintained onsite. The methodology for developing and maintaining this list of components is consistent with the guidance contained in NEI 95-10, Revision 0.

Table 2.3-3 Pressurizer Applicant Action Items from Section 4.1 of BAW-2244A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(1) The renewal applicant is to verify that its plant is bounded by the topical report. This includes confirming that the design of the pressurizer is consistent with that described in the report such that no important pressurizer components exist that have not been addressed in the report.	Entergy Operations participated in the development of BAW-2244A by providing ANO-1 specific design and operational information. Entergy Operations has reviewed the current design and operation of the ANO-1 pressurizer using the process described in Section 2.3.1.2 and confirms that the ANO-1 pressurizer is bounded by the description contained in BAW-2244A.
(2) The renewal applicant is to commit to programs identified as necessary in the report to manage the effects of aging on the functionality of the pressurizer.	Descriptions of these programs are provided in Section 3.2 and Appendix B.
(3) A summary description of these programs is to be provided in the license renewal FSAR supplement in accordance with 10CFR54.21(d).	Summary descriptions of these programs are provided in Appendix A.
(4) Any deviations from the aging management programs described within this report as necessary to manage the effects of aging during the period of extended operation to maintain the functionality of the pressurizer or other information presented in the report, such as materials of construction and edition of the ASME Section XI code (including mandatory appendices), will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10CFR54.21(a)(3).	No deviations from the aging management programs described in BAW-2244A or other information presented in the report have been identified by Entergy Operations.
(5) Since the BWOG defers the development of details of the additional sample volumetric inspection program of small-bore nozzles and safe ends to the renewal applicant referencing this topical report, the renewal applicant will have to provide details of the additional sample inspection program in its renewal application for staff review and approval.	A description of this program is provided in Section 3.2 and Appendix B.

Table 2.3-3 Pressurizer Applicant Action Items from Section 4.1 of BAW-2244A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(6) Since the BWOG elected to exclude TLAAs applicable to the pressurizer from the scope of the topical report and indicated that they will be resolved on a plant-specific basis, any renewal applicant referencing this report will have to evaluate TLAAs applicable to the pressurizer in its renewal application in accordance with the requirements in 10CFR54.21(c).	Evaluations of ANO-1 specific TLAAs are provided in Section 4.0.
BAW-2244 Open Items (Section 4.2)	
(1) Cracking of Stainless Steel Cladding Inside the Pressurizer Vessel (Discussed in section 3.2.1 of the SER) The staff notes that cracking in cladding could potentially propagate into the base metal material and should be addressed by an aging management program. Industry experience at one site has shown that this is a potential aging effect. The staff maintains that cracking of the stainless steel is a potential aging effect that must be addressed by an aging management program for the period of extended operation. A program to provide a reasonable demonstration of the integrity of the pressurizer cladding could be a one-time inspection for license renewal. The inspection should include the cladding and any attachment welds to the cladding. The additional inspection would provide information on the condition of the cladding or, if cracking is discovered, the condition of the underlying base metal as a result of the cracked cladding. The staff notes that the inspection technique chosen (e.g., visual, surface, or volumetric) must be capable of determining the condition of the cladding and must be submitted for staff review and approval. Without such additional aging management program activities, the staff cannot conclude that all aging effects applicable to the pressurizer vessel cladding have been adequately	The ANO-1 program to address pressurizer cladding cracking is provided in the new program entitled "Pressurizer Examinations," which is described in Section 3.2 and Appendix B.

Table 2.3-3 Pressurizer Applicant Action Items from Section 4.1 of BAW-2244A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
addressed by the aging management programs delineated in BAW-2244.	
(2) Aging management of pressurizer heater penetration welds (discussed in Section 3.3.2.2.3 of this SER) The staff regards the provision for examination of pressurizer heater penetration welds in ASME Code, Section XI, ISI Examination Category B-E as applicable to pressurizer heater partial-penetration welds. The BWOG considers the Examination Category B-E requirement not applicable to the B&W design because Examination Category B-E concerns pressure-retaining partial-penetration welds in vessels. The BWOG stated that, "Although the 'Parts Examined' listing under Item B4.20 of Examination Category B-E uses the term 'Heater Penetration Welds,' the 'Extent and Frequency of Examination' specifically requires only 'All Nozzles' to have examination." "There are no heater penetration nozzles or pressure-retaining heater nozzle partial-penetration welds in the vessels of the B&W pressurizer design." The staff disagrees with the BWOG assessment. The B&W pressurizer heaters are inserted through holes in the pressurizer heater bundle diaphragm plates and the heater sheaths (or heater sleeves at ONS-1 and TMI-1) are attached to the diaphragm plates on the inside by partial-penetration welds. The staff does not believe that the B&W heater penetrations are sufficiently different from other vendor designs, except that the B&W heaters are mounted horizontally on the diaphragm plates inserted through the side of the pressurizer shell, while other vendor designs mount the heaters vertically, inserted through the bottom of the pressurizer. In addition, Examination Category B-E explicitly states that the	The ANO-1 program to address inspection of heater penetration welds is provided in the new program entitled "Pressurizer Examinations," which is described Section 3.2 and Appendix B.

Table 2.3-3 Pressurizer Applicant Action Items from Section 4.1 of BAW-2244A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
pressurizer heater penetration welds are to be examined. Therefore, the staff considers the pressurizer heater partial-penetration welds pressure-retaining, and subject to the requirements set forth in ASME Code, Section XI, ISI Examination Category B-E. Operating experience has also shown that pressurizer heater partial-penetration welds are susceptible to cracking. To provide reasonable assurance that cracking of the heater penetration welds and the heater sheath-to-sleeve welds (ONS-1 and TMI-1) will be managed during the period of extended operation, the staff is requesting an additional, more intrusive inspection technique. Specifically, the staff will consider ASME Code, Section XI, ISI Examination Category B-E together with an inspection program consisting of surface examinations (the criteria and technique of which would be developed at a later date and subject to staff approval) for the pressurizer partial-penetration heater sheath-to-heater bundle diaphragm plate welds, heater sleeve-to-heater bundle diaphragm plates welds and heater sheath-to-heater sleeve welds acceptable for managing the effects of cracking for the period of extended operations.	

Table 2.3-4 Reactor Vessel Applicant Action Items from Section 4.1 of BAW-2251A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10CFR54.21(a)(3) and (c)(1).	Entergy Operations participated in the development of BAW-2251A by providing ANO-1 specific design and operational information. Entergy Operations has reviewed the current design and operation of the ANO-1 reactor vessel using the process described in Section 2.3.1.2 and confirms that the ANO-1 reactor vessel is bounded by the description contained in BAW-2251A.
(2) A summary description of the programs and evaluation of TLAAs is to be provided in the license renewal FSAR supplement in accordance with 10CFR54.21(d).	Summary descriptions of these programs are provided in Appendix A.

Table 2.3-4 Reactor Vessel Applicant Action Items from Section 4.1 of BAW-2251A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(3) Since the staff has not made any findings on whether the BWOG topical report provides the complete list of reactor vessel components subject to an aging management review or whether the scoping methodology is adequate, individual plant applicants will need to provide a comprehensive list of structures and components subject to an aging management review and the methodology for developing this list as part of their license renewal applications. Any components determined by the applicant to be subject to an aging management review for license renewal but not within the scope of the topical report are required to be addressed in the license renewal application.	Entergy Operations has reviewed the current design and operation of the ANO-1 reactor vessel using the process described in Section 2.3.1.2 and has confirmed that the ANO-1 reactor vessel is bounded by the description contained in BAW-2251A. No additional RV items were identified as subject to aging management review.
(4) The BWOG has determined that the lower CRDM service support structure, including the weld that connects the lower CRDM service support skirt to the reactor vessel closure head, and the reactor vessel support skirt, including the weld that connects the reactor vessel support skirt to the transition forging, are subject to an aging management review for license renewal. However, the BWOG has decided to exclude them from the scope of the topical report. Thus, a renewal applicant needs to address them in its license renewal application.	The CRDM service support structure and the RV skirt are evaluated in Section 2.4.2.1
(5) The license renewal application for Oconee needs to address the fatigue evaluation of the reactor vessel studs on a plant-specific basis.	This renewal applicant action item is not applicable to ANO-1.

Table 2.3-4 Reactor Vessel Applicant Action Items from Section 4.1 of BAW-2251A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(6) A license renewal applicant needs to discuss the plant-specific methodology and instrumentation used to assess the number of operational transients in its renewal application for staff review. The staff review will also include the number of operating cycles applicable to the reactor vessel studs.	The ANO-1 program that monitors operational transients is described in Section 4.3.5.
(7) The BWOG identifies flaw growth acceptance in accordance with the ASME Section XI ISI program as a TLAA, but indicates that flaw growth acceptance evaluation is plant-specific, is not within the scope of the report, and will be resolved on a plant-specific basis. Thus, a license renewal applicant needs to address it in the renewal application.	The ANO-1 program to manage analytical evaluation of flaws is described in Section 4.3.6.
(8) Alloy 600 components in the reactor vessel such as CRDM housings and other penetrations may be subject to crack initiation and growth. The BWOG originally proposed to use the ASME Section XI program, supplemented by leak detection and surveillance of boric acid, to manage cracking of Alloy 600 components. In an April 1, 1997, response to the staff's request for additional information concerning Generic Letter 97-01, "Stress Corrosion Cracking of Control Rod Drive Mechanisms and Other Vessel Head Penetrations," the BWOG stated: "Each participating plant will address additional requirements for RV head penetrations, including closure head penetrations less than 2 inch N.S. (i.e., thermocouple nozzles at TMI-1 and ONS-2)." Thus, a license renewal applicant referencing the topical report will need to submit its plant-specific program to manage cracking of Alloy 600 components in the reactor vessel in its renewal application for staff review.	The ANO-1 programs that address Alloy 600 penetrations for the period of extended operation include the "Alloy 600 Aging Management Program" and the "CRDM Penetration and Other Vessel Head Penetration Program," which are described in Appendix B.

Table 2.3-4 Reactor Vessel Applicant Action Items from Section 4.1 of BAW-2251A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(9) During the review of the topical report, the staff had a question regarding the need to update the reactor vessel fracture toughness estimates with new data as it become available. In its August 11, 1997, RAI response, the BWOG states: "Each license renewal applicant will define a process to ensure that the time-dependent parameters used in the TLAA evaluations reported in BAW-2251 are tracked such that the TLAA remains valid through the period of extended operation. The process will be defined on a plant-specific basis at the time of the licensee renewal application." Thus, a license renewal applicant needs to describe such a process in its application for staff review. If new information affects the conclusions of the topical report for the applicant's plant, the applicant needs to update its TLAA evaluations as appropriate and provide the updated evaluations in its renewal application for staff review.	See the ANO-1 Reactor Vessel Integrity Program described in Appendix B.
(10) In its August 11, 1997, RAI response, the BWOG indicated that Oconee Unit 2 and TMI Unit 1 will provide updated predictions of RT_{PTS} for welds WF-25 and SA-1526, respectively, when the plant-specific application for license renewal is submitted. For plants with an RT_{PTS} value for 48 EFPY exceeding the corresponding PTS screening criterion, a license renewal applicant must address the requirements in 10CFR50.61(b)(3) by developing, and requesting staff approval for reasonably practicable flux reduction programs to avoid exceeding the PTS criterion.	This renewal applicant action item is not applicable to ANO-1.

Table 2.3-4 Reactor Vessel Applicant Action Items from Section 4.1 of BAW-2251A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(11) If an applicant has installed flow stabilizers using Alloy 600 and/or Alloy 82/182 weld material, the applicant must include the flow stabilizers in its Alloy 600 aging management program. Alloy 600 and Alloy 82/182 weld materials are susceptible to cracking in primary water environments.	The flow stabilizers at ANO-1 are made from austenitic stainless steel and attached to the cladding using stainless steel weldments.
(12) Embrittlement of the reactor vessel will be managed to ensure intended functions of the reactor vessel for 60 years. For the staff to determine if the plant could be operated for 60 years, an applicant must show that an operating window will be available between the pressure-temperature limits and the net positive suction curves for the RCPs for 60 years. Otherwise, the applicant will propose aging management activities to minimize the extent of embrittlement, or other alternatives, to permit safe plant operation for 60 years. Should the applicant show that the reactor could only be operated for a time period less than 60 years, the duration of the renewed license, if granted, would be limited to that time period.	ANO-1 developed 48 EFPY pressure-temperature limits in accordance with the requirements of ASME Section XI, Appendix G, as modified by Code Case N-588 for circumferential flaws in welds and by Code Case N-640 for the use of K_{IC} fracture toughness curve. The operating window at 48 EFPY exceeds the current P-T operating window, which has been approved by the NRC for 31 EFPY. The increased operating window is attributed to the use of Code Cases N-588 and N-640.
(13) The neutron fluence must be experimentally monitored by ex-vessel or in-vessel dosimetry, and if modifications to the design and operation of the plant changes either the neutron energy spectrum, gamma heating or the reactor inlet temperature, as discussed in section 3.3.4.1 of this safety evaluation, the licensee must notify the NRC and propose a program to determine the impact of the modifications.	Reactor vessel fluence monitoring is addressed in the ANO-1 Reactor Vessel Integrity Program that is described in Appendix B.

Table 2.3-5 RV Internals Applicant Action Items from Section 4.1 of BAW-2248A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(1) The license renewal applicant is to verify that the critical parameters for the plant are bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel internals components. The applicant for license renewal will be responsible for describing any such commitments and proposing the appropriate regulatory controls. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel internal components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10CFR54.21(a)(3) and (c)(1).	ANO-1 participated in the development of BAW-2248A by providing ANO-1 specific design and operational information. Entergy Operations has reviewed the current design and operation of the reactor vessel internals using the process described in Section 2.3.1.2 and confirms that ANO-1 is bounded by the description contained in BAW-2248A with regard to critical plant parameters. Reactor vessel internals items that ANO-1 identified as subject to aging management review that were not within the scope of BAW-2248A are described in Section 2.3.1.6. The ANO-1 aging management programs for the reactor vessel internals are described in Appendix B.
(2) A summary description of the programs and evaluation of TLAAs is to be provided in the license renewal FSAR supplement in accordance with 10CFR54.21(d).	Summary descriptions of these programs are provided in Appendix A.

Table 2.3-5 RV Internals Applicant Action Items from Section 4.1 of BAW-2248A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(3) The license renewal applicant must identify whether an intended function of the RVI is to provide shielding for the RPV. If not an intended function, the license renewal applicant should provide justification for that conclusion. Should a license renewal applicant determine that the RVI's intended function is to provide shielding for the RPV, then the items that support this intended function, such as, the thermal shield and the thermal shield upper restraint assemblies, must be identified and reviewed in accordance with 10CFR54.21(a)(3).	Reactor vessel internals intended functions are discussed in Section 2.3.1.6. Three additional intended functions were identified by ANO-1. These additional intended functions and items that support these functions are addressed in Section 2.3.1.6.
(4) Applicants must commit to participation in the BWOG RVIAMP, and any other industry programs as appropriate, to continue the investigation of potential aging effects for RVI components and to establish monitoring and inspection programs for RVI components. The applicant shall provide the NRC with either annual or periodic updates (after completion of significant milestones) on the status of the RVIAMP, commencing within one year of the issuance of the renewed license.	ANO-1 will participate in appropriate BWOG and/or industry level programs to ensure that the RV internals intended functions are maintained consistent with the CLB during the period of extended operation. ANO-1 will provide written reports to the staff upon completion of significant RVIAMP milestones commencing within one year of the issuance of the renewed license.
(5) The applicant must describe plans for augmented inspection of RVI components for management of SCC/IASCC and loss of fracture toughness (neutron embrittlement) of the RVI components. This description should specify the sample size, the examination method, acceptance criteria and timing of the inspection, or the process to be used to specify these items.	See the ANO-1 Reactor Vessel Internals Aging Management Program described in Appendix B.

Table 2.3-5 RV Internals Applicant Action Items from Section 4.1 of BAW-2248A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(6) According to the BWOG, one of its objectives in BAW-2248 states, "It is intended that NRC review and approval of this report will allow that no further review of the matters described herein will be needed when the report is incorporated by reference in a plant specific renewal license application." The license renewal applicant must address the baffle-former bolt cracking issues addressed in Section 3.3.2 of this SE pertaining to Refs. 4 and 5, with regard to the ITG project, initiated after April 23, 1998, to address generic RVI materials issues. The BWOG indicates this industry effort resulted in subsequent changes in the BWOG RVI aging management program. The ITG is currently addressing the issues of cracking of baffle bolts. The BWOG indicates that the changes in the aging management program now requires the applicants to be responsible for using the industry ITG project developed information to determine the necessary steps (e.g., inspection, operability determinations, and replacements) for the management of the applicable baffle bolt aging effects.	See the ANO-1 Reactor Vessel Internals Aging Management Program described in Appendix B.
(7) The applicant must describe plans for augmented inspection of RVI components for management of loss of fracture toughness due to thermal aging embrittlement of the RVI components. This description should specify the sample size, the examination method, acceptance criteria and timing of the inspection, or the process to be used to specify these items.	See the ANO-1 Reactor Vessel Internals Aging Management Program described in Appendix B.

Table 2.3-5 RV Internals Applicant Action Items from Section 4.1 of BAW-2248A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(8) The applicant must describe plans for management of stress relaxation for bolted closures of the RVI. This description should specify the critical locations, and monitoring and inspection techniques, and timing of the inspection, or the process to be used to specify these items.	See the ANO-1 Reactor Vessel Internals Aging Management Program described in Appendix B.
(9) The applicant must address aging management of void swelling. An adequate aging management program (AMP) would include participation in industry program(s) to address the significance of void swelling (either individually or through an owners or industry group), a commitment to develop a sufficient inspection program (including the basis, methods, locations to be examined, timing, frequency and acceptance criteria) for management of the issue based upon the results of the industry programs, and a commitment to implement the inspection program prior to the end of the current license period.	Change of dimensions by void swelling is included in the ANO-1 Reactor Vessel Internals Aging Management Program, which is described in Appendix B.
(10) If flaws have been detected in the reactor vessel internals, a TLAA plant-specific evaluation must be performed to determine the flaw growth acceptance in accordance with the ASME B&PV Code, Section XI, inservice inspection requirements.	No flaws requiring analytical evaluation have been discovered in the inspections of the reactor vessel internals at ANO-1.
(11) The applicant must address the plant-specific plans to continue monitoring and tracking design transient occurrences.	See the description of the ANO-1 Transient Cycle Logging Program in Section 4.3.5.

Table 2.3-5 RV Internals Applicant Action Items from Section 4.1 of BAW-2248A SER	
Renewal Applicant Action Item	**ANO-1 Specific Response**
(12) Plant-specific analysis is required 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. The RVIAMP must develop data to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license.	A plant-specific analysis will be performed to demonstrate that under 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 affect deformation limits. Data will be developed to demonstrate that the internals will meet the deformation limits at the expiration of the renewed license.

Table 2.3-6 Piping and Instrument Diagrams (P&IDs) – Evaluation Boundaries of Engineered Safeguards		
P&ID	**Sheet Number**	**Revision**
Core Flood System		
LRA-M-230	1	Rev. 0
LRA-M-236	1	Rev. 0
Low Pressure Injection/Decay Heat System		
LRA-M-230	1	Rev. 0
LRA-M-231	1	Rev. 0
LRA-M-232	1	Rev. 0
High Pressure Injection/Makeup and Purification System		
LRA-M-230	1	Rev. 0
LRA-M-231	1	Rev. 0
LRA-M-231	2	Rev. 0
LRA-M-231	3	Rev. 0
LRA-M-238	1	Rev. 0
LRA-M-238	2	Rev. 0
Reactor Building Spray System		
LRA-M-236	1	Rev. 0
Reactor Building Cooling and Purge System		
LRA-M-261	1	Rev. 0
Sodium Hydroxide System		
LRA-M-232	1	Rev. 0
LRA-M-233	1	Rev. 0
Reactor Building Isolation System		
LRA-M-206	1	Rev. 0
LRA-M-215	1	Rev. 0
LRA-M-218	5	Rev. 0
LRA-M-220	3	Rev. 0
LRA-M-230	1	Rev. 0
LRA-M-230	2	Rev. 0
LRA-M-233	1	Rev. 0
LRA-M-234	1	Rev. 0
LRA-M-234	2	Rev. 0
LRA-M-236	1	Rev. 0
LRA-M-237	1	Rev. 0
Hydrogen Control System		
LRA-M-237	4	Rev. 0
LRA-M-261	1	Rev. 0
LRA-M-261	3	Rev. 0

Table 2.3-7 Piping and Instrument Diagrams (P&IDs) – Evaluation Boundaries of Auxiliary Systems		
P&ID	**Sheet Number**	**Revision**
Spent Fuel Pool		
LRA-M-232	1	Rev. 0
LRA-M-235	1	Rev. 0
Fire Protection		
LRA-M-219	1	Rev. 0
LRA-M-2219	5	Rev. 0
Emergency Diesel Generator		
LRA-M-217	2	Rev. 0
LRA-M-217	3	Rev. 0
LRA-M-217	4	Rev. 0
Auxiliary Building Sump and Reactor Building Drains		
LRA-M-213	1	Rev. 0
LRA-M-213	2	Rev. 0
LRA-M-214	3	Rev. 0
LRA-M-232	1	Rev. 0
LRA-M-238	1	Rev. 0
LRA-M-238	2	Rev. 0
Alternate AC Diesel Generator		
LRA-M-2241	1	Rev. 0
LRA-M-2241	2	Rev. 0
LRA-M-2241	4	Rev. 0
LRA-M-2241	5	Rev. 0
LRA-M-2260	4	Rev. 0
Halon		
LRA-M-219	2	Rev. 0
Fuel Oil		
LRA-M-217	1	Rev. 0
LRA-M-217	2	Rev. 0
LRA-M-217	3	Rev. 0
LRA-M-219	1	Rev. 0
LRA-M-2241	3	Rev. 0
Instrument Air		
LRA-M-206	2	Rev. 0
LRA-M-210	1	Rev. 0
LRA-M-213	2	Rev. 0
LRA-M-215	1	Rev. 0
LRA-M-218	4	Rev. 0
LRA-M-222	1	Rev. 0
LRA-M-230	2	Rev. 0
LRA-M-232	1	Rev. 0

Table 2.3-7 Piping and Instrument Diagrams (P&IDs) – Evaluation Boundaries of Auxiliary Systems		
P&ID	**Sheet Number**	**Revision**
LRA-M-233	1	Rev. 0
LRA-M-234	1	Rev. 0
LRA-M-234	2	Rev. 0
LRA-M-237	1	Rev. 0
LRA-M-261	1	Rev. 0
LRA-M-262	1	Rev. 0
LRA-M-262	2	Rev. 0
LRA-M-262	3	Rev. 0
LRA-M-262	4	Rev. 0
LRA-M-263	1	Rev. 0
Chilled Water		
LRA-M-221	2	Rev. 0
LRA-M-222	1	Rev. 0
Service Water		
LRA-M-204	3	Rev. 0
LRA-M-209	1	Rev. 0
LRA-M-210	1	Rev. 0
LRA-M-221	2	Rev. 0
Penetration Room Ventilation		
LRA-M-264	1	Rev. 0
Auxiliary Building Heating and Ventilation		
LRA-M-262	3	Rev. 0
LRA-M-262	4	Rev. 0
LRA-M-263	2	Rev. 0
LRA-M-263	3	Rev. 0
Control Room Ventilation		
LRA-M-2221	2	Rev. 0
LRA-M-263	1	Rev. 0

Table 2.3-8 Piping and Instrument Diagrams (P&IDs) – Evaluation Boundaries of Steam and Power Conversion Systems		
P&ID	**Sheet Number**	**Revision**
Main Steam System		
LRA-M-204	6	Rev. 0
LRA-M-206	1	Rev. 0
LRA-M-206	2	Rev. 0
Main Feedwater System		
LRA-M-206	1	Rev. 0
Emergency Feedwater System		
LRA-M-204	3	Rev. 0
LRA-M-204	6	Rev. 0
LRA-M-206	1	Rev. 0
Condensate Storage and Transfer System		
LRA-M-204	3	Rev. 0
LRA-M-204	5	Rev. 0

2.4 STRUCTURES AND STRUCTURAL COMPONENTS SCOPING AND SCREENING RESULTS

2.4.1 Reactor Building

The determination of ANO-1 structures within the scope of license renewal is made by initially identifying structures and then reviewing each structure to determine which ones satisfy one or more of the criteria contained in 10CFR54.4. This section contains the information required by 10CFR54.21(a)(1) and (a)(2) for the ANO-1 reactor building (which provides the containment function) structural components that are subject to aging management review for license renewal.

The ANO-1 reactor building is identified as a seismic category 1 structure in the ANO-1 SAR Section 5.2. Seismic category 1 structures are those which prevent uncontrolled release of radioactivity and are designed to withstand design basis loading conditions without loss of function. Accordingly, seismic category 1 structures meet the criteria of 10CFR54.4(a)(1) and are within the scope of license renewal. Therefore, the ANO-1 reactor building is within the scope of license renewal. A portion of the reactor building serves as an important element in the radioactive release line-of-defense and therefore, receives special focus in the integrated plant assessment. The reactor building includes the concrete reactor building structure, liner, and penetrations.

The ANO-1 reactor building is a composite structure consisting of a post-tensioned, reinforced concrete structure with cylindrical wall, a flat foundation slab, and a shallow dome roof. SAR Figure 5-1 is an illustration of the ANO-1 prestressed concrete reactor building. The reactor building completely encloses the reactor and the associated RCS along with other electrical, mechanical and structural components. The cylinder wall integrity is provided by a post-tensioning system consisting of horizontal and vertical tendons in the cylinder wall. Dome integrity is provided by three sets of tendons with each set oriented 120 degrees from the other. The concrete foundation slab is conventionally reinforced. The entire structure is internally lined with a carbon steel liner plate to assure a high degree of leak tightness.

The reactor building structure is subdivided into component groupings for the aging management review. Many structural components are not typically associated with unique equipment identifiers and thus, are not individually identified during the identification of components subject to aging management review. Specific structural component identifiers are not needed because the aging management review process and resulting programmatic oversight was performed across an entire component grouping.

The intended functions of the reactor building were determined by reviewing information contained in the ANO-1 SAR and ANO-1 engineering documents, as well as NEI 95-10 (Reference 2.4-1). The reactor building and its structural components fulfill the following intended functions.

- Provide essentially leak tight barriers to prevent uncontrolled release of radioactivity

- Provide structural support or functional support to safety-related systems, structures, and components. Specifically, for the post-tensioning systems, this function means to impose compressive forces on the concrete reactor building structure to resist, with no loss of structural integrity, the internal pressure resulting from a DBA.
- Provide shelter or protection to safety-related equipment (including radiation shielding)
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas
- Serve as external missile barriers
- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide a heat sink during DBA or station blackout conditions

The ANO-1 reactor building structural components within the scope of 10CFR Part 54 were reviewed to determine those components subject to an aging management review in accordance with 10CFR54.21(a)(1). An aging management review of a structural component is required if the component performs an intended function without moving parts or without a change in configuration or properties (i.e., passive) and if it is not subject to replacement based on a qualified life or specified time period (i.e., long-lived). Consistent with the guidance provided in NEI 95-10, the reactor building structural components within the scope of license renewal are long-lived and passive and require an aging management review.

A listing of the reactor building passive, long-lived components and unique commodities subject to an aging management review, and their intended function(s), is provided in Table 3.6-2. This list has been derived from individual reactor building components identified in ANO-1 specific documents maintained onsite. Components which do not perform an intended function are not within the scope of license renewal.

The reactor building structural components have been divided into three groups based on material of construction and component-level function. They are steel, concrete, and the post tensioning system. These component groups are described in the following sections.

2.4.1.1 Steel Components

Liner Plate

The interior of the reactor building is lined with a steel liner plate of welded construction. The liner plate covers the dome, the cylinder wall and also runs between the floor and the foundation slab to form an essentially leak tight barrier. The ANO-1 reactor building liner plate is an ASTM A36 (Reference 2.4-2) or A516 (Reference 2.4-3) plate attached to the concrete by means of an angle grid system of ASTM A36 material stitch welded to the liner plate and embedded in the concrete. The liner plate is anchored in both the longitudinal and hoop directions.

The anchor spacing and welds are designed to preclude failure of an individual anchor. The frequent anchoring is designed to prevent significant distortion of the liner plate during accident conditions and to ensure that the liner maintains its essentially leak tight integrity.

Before the reactor building penetrations were embedded in concrete, they were continuously welded to the liner plate. The entire length of every weld was leak tested following fabrication. Radiographs were taken of at least one foot out of every 50 feet of welding completed by each welder during fabrication.

The liner plate is coated on the inside with inorganic zinc primer for corrosion protection. There is no coating on the side in contact with the concrete. At the penetrations, the liner plate is thickened to reduce stresses in accordance with the ASME Code (Reference 2.4-4). The liner was designed as a free standing vessel for erection loads and was used as the internal form for the concrete. The liner plate is thickened at large attachments, such as the polar crane brackets, to accommodate strength and welding requirements for the attachments and anchors. The general liner configuration is shown in SAR Figure 5-1.

ASME Section III (Reference 2.4-5) is used as the basis for establishing allowable liner plate strains and stresses. ASME Section III requires that the liner material be prevented from experiencing significant distortion due to thermal loads and that stresses be considered from a fatigue standpoint.

Anchors/Embedments/Attachments

Anchors and embedments are steel commodities, such as angles and anchor studs that are welded to the liner and anchor the liner to the reactor building concrete shell. A typical liner anchor is shown in SAR Figure 5-28. In addition, other anchors and embedments are provided to transfer loads into the concrete cylinder wall or foundation mat from attachments to the liner. In these cases, a thickened insert plate is welded to the liner and is used as the point of attachment for the anchor. The polar crane bracket is anchored to the concrete shell by a welded plate assembly embedded in the concrete.

The anchors and embedments maintain the essentially leak tight barrier by preserving the integrity of the liner. The load carrying capacity of these anchor is also required to assure that the supported equipment, such as the polar crane or the steam generators, can continue to perform safely.

Attachments to the liner that are integral with the liner and concrete structure (i.e., attachment has corresponding anchor in concrete) are connected to the inside face of the liner and thus exposed to the interior of the reactor building. The polar crane brackets are examples of attachments to the liner.

The polar crane brackets consist of welded carbon steel plates, constructed of the same material as the liner. The Polar crane brackets were inspected using requirements similar to those for the liner. Other attachments to the liner include structural steel attachments that are welded directly to the liner to support various structures and components.

Attachment welds are not considered to be within the evaluation boundary of the reactor building. However, these attachment welds are considered to be within the evaluation boundary of reactor building internal structural components that are addressed in Section 2.4.2.

Personnel Hatches

Two hatches are provided into the reactor building for personnel access and egress (see SAR Figure 5-3). The larger personnel hatch is used as the primary access to the reactor building. The smaller personnel hatch is used for emergency egress. The personnel hatches are double-door, welded steel assemblies. The hatches are designed to withstand reactor building design conditions with either, or both, doors closed and locked. The doors open toward the center of the reactor building, preventing unseating of the doors during reactor building pressurization. The personnel hatches may be individually pressurized to demonstrate leak tightness. Quick-acting, equalizing valves connect the air within each personnel hatch with the air inside and outside of the reactor building. These valves equalize the pressures on either side of a hatch door when it is operated. The equalizing valves are active components of the hatches and do not require an aging management review. Functionality of the equalizing valves is verified periodically when the hatches are pressurized and tested for leakage.

The personnel hatches contain operating mechanisms, which include gears, latches, hinges, linkages, etc., to open and close the doors of the hatch. These operating mechanisms perform their function with moving parts and with a change of configuration. Both the larger personnel hatch and the smaller emergency hatch are required to be operable, as defined by ANO-1 Technical Specifications. Surveillance requirements are also included in ANO-1 Technical Specifications. Actions are required to be taken, up to and including plant shutdown, if one or more of the hatch doors become inoperable.

The Statement of Considerations of the final 10CFR Part 54 rule states that:

"... many licensee programs that ensure compliance with technical specifications are based on surveillance activities that monitor performance of systems, structures, and components that perform active functions. As a result of the continued applicability of existing programs and regulatory requirements, the Commission believes that active functions of systems, structures, and components will be reasonably assured in any period of extended operation."

Also, 10CFR54.21(a)(1)(i) states that:

"structures and components subject to an aging management review shall encompass those structures and components that perform an intended function, as described in 10CFR54.4, without moving parts or without a change in configuration or properties...".

Accordingly, since the hatch operating mechanisms perform their intended functions with moving parts and a change of configuration, Entergy Operations has determined that the reactor building hatch operating mechanisms are not subject to an aging management review.

The two doors of each personnel hatch are interlocked to ensure that reactor building integrity is always maintained by one door being completely closed before the other door can be opened. The interlocking system has a bypass, allowing the doors to open simultaneously during plant cold shutdown. The interlock system is an active component of the personnel hatch and is not subject to an aging management review. Serviceability of the interlock system is verified during periodic personnel hatch leakage testing as well as during periodic maintenance.

Each personnel hatch door is provided with flexible seals. The seals are replaced when warranted by their condition. The seals are not long-lived components and therefore do not require an aging management review.

The hatches were designed and fabricated in accordance with the ASME Section III requirements for Class B vessels. The plate materials that comprise the personnel hatches' pressure vessel components are painted carbon steel complying with material specification ASTM A516, Grade 70, made to ASTM A300 (Reference 2.4-6) specification, for fine grained materials with ductile material properties suitable for low temperature use.

Equipment Hatch

A single equipment hatch as shown in SAR Figure 5-3 is provided for the reactor building. The equipment hatch design and fabrication conform to the ASME Code for Class B vessels. As with the personnel hatches, the equipment hatch was fabricated using A516 Grade 70, painted carbon steel made to ASTM A300 specification.

The equipment hatch is furnished with a double sealed flange and bolted, dished head. The barrel portion of the equipment hatch is thicker than required based on permissible stresses. The space between the double seals on the equipment hatch flange can be pressurized for local leakage testing. As with the personnel hatches, the flexible seals are tested and replaced when warranted by condition. The seals are not long-lived, passive components and do not require an aging management review.

Mechanical Penetrations

The penetrations through the reactor building pressure boundary are designed to maintain the essentially leak tight barrier to prevent uncontrolled release of radioactivity. In addition to supporting the essentially leak tight barrier function, each penetration performs service related functions. Penetrations may also serve as support points for piping passing through the reactor building pressure boundary.

Penetration plate and sleeve material is ASTM A516 Grade 70 material. The plate material is also fabricated to specification ASTM A300.

Mechanical penetrations provide the means for passage of process piping transmitting liquids or gases across the reactor building boundary. A typical mechanical piping penetration, a single barrier piping penetration with a single closure between the process pipe and the reactor building liner, is shown in SAR Figure 5-3.

The penetrations are solidly anchored to the reactor building wall or foundation slab, precluding any requirements for expansion bellows. In accordance with the design requirement of ASME Section III, the piping penetration reinforcing plates and the pipe closure weldments were stress relieved.

A mechanical penetration's boundary for the LRA includes the entire penetration assembly, including the weld to the process piping, but not the process piping within the penetration. Penetrations are designed to maintain the adjacent concrete within an acceptable temperature range. Bellows are not installed in the reactor building penetrations at ANO-1. The reactor building evaluation boundary is shown on ANO-1 SAR Figure 5-3, Detail 5. Spare penetrations consist of a sleeve with welded end cap closure(s) or bolted blind flange plate(s) with gaskets at both ends of the penetration sleeve. During an outage, spare penetrations can readily be converted into additional permanent mechanical or electrical penetrations. The entire spare penetration assembly is considered in the ANO- 1 LRA.

Electrical Penetrations

Electrical penetrations provide the means for electrical and instrumentation conductors to cross the reactor building pressure boundary, while maintaining the essentially leak tight barrier. An electrical penetration through the reactor building is shown in SAR Figure 5-2, Detail 3. The LRA scope includes the metallic components of the electrical penetration that are part of the reactor building's essentially leak tight barrier. The inside steel header plate for the electrical terminals is included in the scope. The wiring, sealing compound, fixtures to hold the sealing compound, and seal welds of the fixtures to the header plate are addressed in environmental qualification reports. Environmental qualification of electrical penetrations is addressed in Section 4.4.

Fuel Transfer Tube

A fuel transfer tube penetrates the reactor building, linking the refueling canal inside the reactor building with the fuel transfer canal in the fuel handling building. This is the underwater pathway for moving fuel assemblies into and out of the reactor building during refueling operations. As part of the reactor building, the tube must assure the essentially leak tight barrier function for the design basis conditions.

The fuel transfer tube arrangement is shown in SAR Figure 5-2, Detail 10. As shown in the figure, the closure between the transfer tube and the sleeve that is integrally welded to the reactor building liner, consists of a circular plate shop welded to the tube and a short segment of pipe to mate with the sleeve.

The transfer tube, blind flange, and gate valve are part of the spent fuel pool system and are addressed in Section 2.3.3.1 and Table 3.4-1.

2.4.1.2 Concrete

Dome and Cylinder Walls

The reinforced concrete dome and cylinder walls are prestressed by a post-tensioning system, as shown in SAR Figure 5-1. The combined strength provided by the concrete, conventional reinforcing steel, and the post-tensioning system is used to satisfy the design loads. Although these three material components act together as one composite system, the post-tensioning system is addressed as a separate component because it is installed and stressed after the reinforced concrete components are complete and because of the unique tendon surveillance program.

Conventional reinforcing is provided near the surface of the cylinder walls and dome primarily to resist local moment and shear loads at discontinuities and for temperature and shrinkage crack control. The conventional reinforcing is accounted for in the strength design of the concrete sections for the internal shear forces and moments resulting from the design loadings.

The concrete sections are thickened and the conventional reinforcing steel is increased at the structural discontinuities to account for the increased stresses in those local areas. Primary structural discontinuities occur at the base of the cylinder and at the transition of the cylinder walls and dome to the ring girder. The ring girder serves as the anchorage area for the upper end of the vertical tendons and for both ends of the dome tendons. Six vertical buttresses are provided along the exterior face of the cylinder to serve as the anchorage points for the hoop tendons. The hoop tendons extend for 120 degrees of arc. Supplementary reinforcing steel is provided at tendon anchorage zones to account for the local forces at the anchorage. The concrete cylinder walls are also thickened and additional reinforcing is provided locally at the equipment hatch to account for the flow of forces in the walls around the relatively large diameter opening required for the hatch. Additionally, the concrete dome is coated with an elastomeric silicone rubber on the exterior to protect the dome from weathering conditions.

Floor

A reinforced concrete floor is provided in the reactor building, above the embedded portion of the liner plate, to protect the liner plate from punctures that could breach the essentially leak tight barrier.

Foundation Slab

The conventionally reinforced concrete foundation slab serves as the structural foundation support for the reactor building. The vertical tendons extend through the foundation slab thickness and are anchored on the underside of the slab. A reinforced concrete enclosure, the lower tendon access gallery, shown in SAR Figure 5-1, is provided at the underside of the foundation slab for access to the lower vertical tendon anchorages for tendon installation and surveillance purposes. The lower tendon access gallery and the foundation slab are constructed of separate concrete pours with horizontal and vertical isolation joints provided. The lower tendon access gallery does not support the intended functions of the reactor building and is therefore, not within the scope of license renewal.

2.4.1.3 Post-Tensioning System

An elevation section of the ANO-1 reactor building (SAR Figure 5-1) shows the orientation of the tendons. A section of a typical post-tensioned tendon assembly is also shown in SAR Figure 5-1.

The reactor building cylinder wall is prestressed by 102 vertical tendons anchored at the top surface of the upper ring girder at the top of the concrete cylinder and at the bottom of the foundation slab. The reactor building cylinder wall is also prestressed with three groups of 57 hoop tendons, minus two tendons that were not installed due to obstructed sheathing. These tendons encompass an arc of 240° for a total of 169 tendons anchored at the three vertical buttresses.

The reactor building dome is prestressed by three groups of 30 tendons oriented at 120° to each other, for a total of 90 tendons anchored at the vertical face of the upper ring girder. Each tendon consists of 186 wires bundled together. Conduits and bearing plates are cast into the concrete shell to receive the tendons, which were installed after construction of the reinforced concrete was complete. The tendons are continuous from anchorage to anchorage, being deflected around penetrations. The post-tensioning system is shown on SAR Figure 5-4. The design of the tendon system provides for the loss of any three adjacent tendons in any of the groups without significantly affecting the load carrying capacity of the reactor building.

The Birkenmeier Brandestinin Ros Vogt system uses parallel wires with cold-formed buttonheads at the ends, which bear upon a perforated steel anchor head, thus providing a positive mechanical means for transferring the prestress force into the concrete shell. Extensive prototypical static, dynamic, and low-temperature testing have been performed on the Birkenmeier Brandestinin Ros Vogt anchorage system to assure that the ultimate capacity of the tendons can be developed.

The post-tensioning system is the primary means of satisfying the controlling design loads of the structure, although the conventional mild steel reinforcing is taken into account when checking representative sections of the structure's internal forces and moments resulting from the load combinations. The tendon stress remains in the elastic range for the controlling design load combinations.

2.4.2 Reactor Building Internals

The reactor building internals are reinforced concrete and steel structures, supported by the reactor building. The reactor building internals consist of the reactor cavity, two steam generator compartments, and a fuel transfer canal that is located between the two steam generator compartments and above the reactor cavity. The reactor cavity houses the reactor pressure vessel and serves as a radiation shield. Also in the cavities are structural steel, platforms, ladders, and grating for access to the various components for inspection and maintenance.

The steam generator compartments house the steam generators and other components of the RCS, including the reactor coolant pumps. The pressurizer is housed in a separate compartment adjacent to and integral to a steam generator compartment. The primary function of the steam generator compartment walls, commonly referred to as "D-rings" is to serve as secondary shield walls in order to resist the pressure jet loads due to pipe rupture. The dynamic effects caused by the impingement of the jet force on the "D-rings" walls are also considered in the design. The reactor building internals design also considers the effects of radiation and radiation generated heat.

The reactor building internals comprise various structural components, which support or protect in-scope system components or equipment. The reactor building internals fulfill the following intended functions.

- Provide structural support or functional support to safety-related equipment
- Provide shelter or protection to safety-related equipment (including radiation shielding)
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas
- Serve as internal missile barriers
- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide a heat sink during DBA or station blackout conditions

A listing of the reactor building internals passive, long-lived components and unique commodities subject to an aging management review, and their intended functions, is provided in Table 3.6-3.

2.4.2.1 Steel

Illustrations of the reactor building internals steel components are provided in SAR Figure 5-8. Structural carbon steel is provided in the reactor building to allow access to the various elevations and areas inside reactor building for inspection and maintenance. The steel also provides support for several nuclear safety-related components, including core flood tanks, reactor building cooling units, emergency core cooling system piping, and electrical instrumentation, control and power.

Part of the floor surface is reinforced concrete, and the remainder is galvanized steel grating. The floor beams are supported by columns or by attachments to the exterior surface of the secondary shield wall. Structural steel, welded to the liner plate, also provides grating support. Attachment welds to the liner plate are within the evaluation boundary of the LRA.

Cranes

The ANO-1 reactor building internals also support various cranes for different maintenance applications. Illustrations of the reactor building crane components are provided in SAR Figure 9-48. The following reactor building crane components are within the scope of license renewal and subject to aging management review.

- Main fuel handling bridge
- Auxiliary fuel handling bridge (abandoned)
- Jib cranes
- Polar crane

These components are being addressed since their potential failure when lifting or carrying heavy loads may impact safety-related components. Therefore, their structural integrity must be maintained. The main and auxiliary fuel handling bridges and control rod drive crane are supported on the secondary shield walls. The fuel tilt machine travels through the transfer tube cast in the cylindrical wall. The fuel tilt machine permits movement of fuel in and out of the reactor building. The control rod drive crane and fuel tilt machine are category 2 structures. Their failure would not impact safety-related components. Therefore, they are not in-scope. The transfer tube is designed to isolate reactor building internals during plant operations with a blank flange on the reactor building internals side and a gate valve on the spent fuel pool side.

Control Rod Drive Service Structure

The control rod drive service structure located on top of the reactor vessel, supports the control rod drive mechanisms from excessive lateral motion to ensure that the control rods can drop into the core under design basis loading condition. The control rod drive service structure consists of five major assemblies.

- Lower control rod drive service structure skirt: A slotted carbon steel cylinder is welded to the upper surface of the reactor vessel closure head. A mating flange is welded to the skirt, providing a seating surface to which the upper control rod drive service structure is bolted.
- Upper control rod drive service structure skirt: A carbon steel cylindrical shell, with a lower flange, connects to the lower control rod drive service structure skirt. An upper flange connects to the closure head service structure shell flange.

- Closure Head Service Structure Shell: A carbon steel cylinder, attached to the upper control rod drive service structure skirt, supports the control rod drive service structure platform assembly.
- Control Rod Drive Service Structure Strut Support Assembly: Horizontal carbon steel beams, oriented in a radial direction, are welded to the closure head service structure shell on one end and supported on the other by angled beams.
- Control Rod Drive Service Structure Platform Assembly: A horizontal platform made of carbon steel beams is attached to the top of the closure head service structure shell and the control rod drive service structure strut support assembly. The control rod drive service structure platform assembly restrains the top ends of the control rod drive mechanisms from lateral movement during design basis loading.

Reactor Vessel Support Skirt

The reactor vessel supports include a support skirt and support flange. The reactor vessel support skirt is a cylindrical structure that supports the reactor vessel. The support skirt rests on a sole plate. The sole plate is fixed to a supporting, reinforced concrete pedestal through a steel flange bolted to the pedestal. The evaluation boundary of the reactor vessel support skirt begins at the weld of the skirt to the reactor vessel transition forging and terminates at the bottom of the skirt flange. The evaluation boundary also includes the exposed surface of the anchor bolts and shear pins.

The reactor vessel support skirt was designed, fabricated, tested, and inspected in accordance with ASME Section III (Reference 2.4-5). The support skirt consists of two carbon steel semi-circular rings welded together to form a cylinder. This cylinder is welded to the bottom of the reactor vessel transition forging. The cylinder has holes for ventilation of the reactor vessel cavity. The anchor bolts are prestressed to accommodate the loads of a design basis seismic event.

2.4.2.2 Concrete

The reactor building internals are supported by the reactor building. Structural reinforced concrete forms the basement floor slab (cover over the liner plate); columns; the walls surrounding the steam generators, reactor, and pressurizer; valve pits and pipe chases; other interior walls; the slabs of the valve pits and pipe chases; missile shields; fuel transfer canal; and the removable concrete hatches and covers. The concrete utilized in the reactor building internals meets the requirements of ANO-1 specifications.

2.4.3 Auxiliary Building

The ANO-1 auxiliary building is structurally independent from other structures. It is located adjacent to the ANO-1 reactor building and the turbine building, but is seismically separated from them by one-inch wide joints filled with an elastic resilient material. It is a conventionally designed, reinforced concrete structure founded on bedrock. The auxiliary building has reinforced concrete foundation mats at elevation 317' and elevation 335'. Reinforced concrete floor slabs are at elevations 335', 354', 372', 386', and 404'.

The concrete substructure and concrete walls and floors are designed for dead, live, and lateral loads. Seismic, wind, and other loads are carried to the foundation by diaphragm action in slabs and shear wall action in walls. The building is partly above grade (i.e., grade is at elevation 354') and partly below grade. Exterior concrete construction joints contain waterstops at joints below the plant's design flood level of elevation 361'.

The auxiliary building houses various systems that support normal operation, shutdown, and accident conditions of ANO-1. Most areas within the auxiliary building are classified and designed as seismic category 1 structures. Seismic category 1 structures are those whose failure could cause the uncontrolled release of radioactivity or are essential for safe reactor shutdown and the immediate and long-term operation following a loss of coolant accident. Some of the category 1 areas significant to plant safety include the control room, spent and new fuel shipment and storage facilities, and the cable spreading room. Category 1 areas have been determined to be within the scope of 10CFR54.4(a)(1).

Several internal boundaries within the auxiliary building are classified as seismic category 2 structures. Seismic category 2 structures are those whose failure may interrupt power generation, but will not prevent a safe reactor shutdown. However, failure of some of the category 2 areas within the auxiliary building (i.e., the liner plate within the spent fuel pool area and the small pipe chase at elevation 341', which is structurally connected to the category 1 wall along column line H) could possibly affect the function of a safety-related structure, system, or component. These category 2 areas are within the scope of 10CFR54.4(a)(2).

In addition, some areas within the auxiliary building (i.e., areas with 10CFR50.48-required fire barriers) are within the scope of 10CFR54.4(a)(3).

The boron holdup tank vault is located below grade, and is structurally connected to the auxiliary building,. The borated water storage tank sits on top of the vault. The post-accident sampling system building is anchored to the top of the ANO-1 and ANO-2 tank vaults (elevation 355'-4"). It contains category 2 equipment, but was designed to category 1 criteria to avoid potential interaction with safety-related equipment.

The auxiliary building comprises various structural components and commodities, which support or protect in-scope system components or equipment. The auxiliary building and its structural components and commodities fulfill the following intended functions.

- Provide essentially leak tight barriers to prevent uncontrolled release of radioactivity

- Provide structural support or functional support to safety-related equipment
- Provide shelter or protection to safety-related equipment (including radiation shielding)
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas
- Serve as missile (internal or external) barriers
- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide protective barriers for internal flood event
- Provide protective barriers for external flood event
- Provide for storage of spent fuel assemblies

A listing of the auxiliary building passive, long-lived components and unique commodities, subject to an aging management review, is provided in Table 3.6-4. Components and commodities are grouped based on materials of construction, with sub-materials indicated as appropriate. Structural intended functions by component and commodity are also listed. The construction materials for the auxiliary building components and commodities are steel, threaded fasteners, and concrete (excluding prestressed concrete), and elastomers. In the material group fire barriers, fire doors are grouped as steel components, while fire walls and slabs are concrete components. Although the turbine building itself is not within the scope of license renewal, some fire doors and fire walls and slabs (10CFR50.48-required) within the turbine building are in-scope and subject to aging management review. These are addressed along with those for the auxiliary building. For the material group elastomers, none of the components or unique commodities are subject to an aging management review. There are no components or unique commodities associated with the material groups earthen structures or Teflon.

Commodities considered common to the auxiliary building and other in-scope structures are discussed in Section 2.4.6.2.

2.4.4 Intake Structure

The intake structure houses the circulating water, fire, and service water pumps, motor control centers, and traveling screens. It is a conventionally designed reinforced concrete structure founded on bedrock and located at the termination of the intake canal. The structure can be divided into two major sections. The first section is the portion of the building above grade elevation (El. 353'-3"). The remaining section is the pump bay area located below grade and partially submerged in water.

The above grade section contains pump motors, valve motor actuators, and related equipment. This section of the building has three predominant elevations which are elevation 354', elevation 366', and elevation 378'. HVAC equipment is located in the penthouse at elevation 378'. Pump motors and valve motor actuators required for plant protection (i.e., fire water and service water) are located on elevation 366', which is above the plant design flood level of elevation 361'. Generally, the remaining pump motors required for normal plant operation, such as the circulating water and screen wash pumps, are located on elevation 354'. System components related to plant protection, which are not adversely affected by flood waters or which would not be required during a flooding event (i.e., the lake/emergency cooling pond sluice gate actuators), are also located on elevation 354'.

The below grade portion of the intake structure contains the pump bays for various plant systems. The four circulating water system bays take their suction directly from Lake Dardanelle. Three service water system bays are located directly behind the circulating water bays. Depending on plant conditions, sluice gates in the service water bays can be aligned so that the fire water and service water pumps can take suction directly from Lake Dardanelle or from the emergency cooling pond.

The ANO-1 intake structure is integrally connected to the ANO-2 intake structure with a shear key and a row of reinforcing bars near the elevation 354' slabs. The intake structure gantry crane (L-007) is shared between the ANO-1 and ANO-2 intake structures. The gantry crane is supported by steel crane rails and girders on reinforced concrete piers. Procedurally, it is parked at a safe distance from the intake structure.

The portions of the intake structure required to be seismic category 1 are those that provide support to service water system components. The remainder of the building is seismic category 2. Thus, the portion of the intake structure housing seismic category 1 system components has been designed to category 1 standards to ensure the safe operation of the service water pumps. Category 1 building areas have been determined to be within the scope of 10CFR54.4(a)(1). Category 2 building areas in the intake structure are not within the scope of 10CFR54.4(a)(2).

The intake structure comprises various structural components and commodities, which support or protect in-scope system components or equipment. The intake structure and its structural components and commodities fulfill the following intended functions.

- Provide structural support or functional support to safety-related equipment

- Provide shelter or protection to safety-related equipment
- Serve as missile (internal or external) barriers
- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide protective barriers for external flood event

A listing of the intake structure passive, long-lived components and unique commodities, subject to an aging management review, is provided in Table 3.6-5. Components and commodities are grouped based on materials of construction, with sub-materials indicated as appropriate. Structural intended functions by component and commodity are also listed. The construction materials for the intake structure components and commodities are steel, threaded fasteners, and concrete (excluding prestressed concrete). For the material group fire barriers, there are no components or commodities within the scope of license renewal (i.e., none are 10CFR50.48-required). None of the components or unique commodities for the material group elastomers are subject to an aging management review and there are no components or commodities associated with the material groups earthen structures or Teflon.

Commodities considered common to the intake structure and other in-scope structures are discussed in Section 2.4.6.2.

2.4.5 Earthen Embankments

The structures included within this group for aging management review are earthen embankments submerged partially, or totally, in Lake Dardanelle and contained within their own boundaries. The following seismic category 1 structures are evaluated within this group.

- Emergency cooling pond
- Intake and discharge canals

The ANO-1 earthen embankments provide a heat sink during DBA or station blackout conditions. A listing of the earthen embankments components subject to an aging management review and their intended function, is provided in Table 3.6-6.

2.4.5.1 Emergency Cooling Pond

The emergency cooling pond is a seismic category 1, 14-acre, kidney-shaped pond located northwest of the plant. A general layout of the ECP is shown in SAR Figure 9-32. The bottom of the pond is at elevation 341 feet, with normal water level between five and six feet. The maximum ECP level of six feet is maintained by a spillway that discharges back to Lake Dardanelle. Plant discharge (ECP inlet) flows into a structure that is surrounded by a 100 foot long weir that peaks at elevation 346 feet. The purpose of the weir is to promote a uniform flow distribution in the ECP and direct the hot discharge to the surface. This maximizes the surface temperature, which maximizes heat rejection. The plant intake piping is at the lowest point of the ECP, with the pipe centerline at elevation 339.5 feet. The location of supply and return lines at opposite extremes serves to prevent a hydraulic short circuit.

The ECP is excavated in impervious clay strata with the bottom of the pond about 4 to 16 feet above rock. To preclude undercutting by water flow over the spillway, the downstream sections of the spillway crest voids and the adjacent embankment voids are pumped with an elastic type of grout. Also, a filter fabric material has been placed below, and an impervious membrane fabric placed above, the articulated concrete slabs to deter erosion. The pond side slopes are protected against wave action by 18 inches of riprap placed on the north side of the pond, to eliminate leakage through the existing filter material to the underdrain. A series of weirs assists in elimination of silt problems.

The ECP serves as a heat sink in the unlikely event of a loss of Lake Dardanelle water inventory. Under controlled conditions, with Lake Dardanelle available, the ECP may provide service water or auxiliary cooling water to ANO-1 with ANO-2 or ANO-1 providing normal makeup as necessary to preserve ECP inventory.

2.4.5.2 Intake and Discharge Canals

The intake canal supplies the reservoir water to ANO-1 for once-through cooling. It is also used to supply cooling tower makeup water and service water for ANO-2. The intake canal conveys water from the Illinois Bayou portion of Lake Dardanelle to the intake structure. It is approximately 4,000 feet long and, at normal pool elevation of 338 feet, the width varies from 80 feet at the mouth to 135 feet at the intake structure, with an average depth of 14 feet.

The intake canal deepens and widens before reaching the intake structure. This feature causes debris entrained in the lake water to drop out of suspension and collect in this area. This prevents excessive amounts of silt from entering the service water system. The discharge canal returns the cooling water to the reservoir. It is approximately 600 feet long and has an average width of 165 feet and with an average depth of 11 feet at normal pool elevation of 338 feet. Both canals are completely excavated and contain no sections formed by dikes or in-fill. Bank slopes are planted with grass or protected by rip-rap to prevent erosion. These canals are within the scope of license renewal and subject to aging management review.

2.4.6 Other Structures and Structural Components

2.4.6.1 Aboveground/Underground Yard Structures

The ANO-1 aboveground/underground structures and trenches requiring an aging management review are the following.

- Q-Condensate storage tank foundation
- Emergency diesel fuel oil storage tank vault
- Bulk fuel oil storage tank foundation
- Alternate AC diesel generator building foundation
- Electrical manholes
- Borated water storage tank foundation

Most of the above structures are seismic category 1 and their structural function is to provide support or protection to seismic category 1 (Q, safety-related) and/or seismic category 2 (non-Q, non-safety-related) equipment and components.

Q-Condensate Storage Tank Foundation

The Q-CST, including the valve pit and pipe trench, is a seismic category 1 structure located on the west side of the ANO-1 reactor building. The Q-CST is supported on a 2'-6" thick by 52 foot reinforced concrete octagon-shaped mat foundation. The foundation is supported on 42" diameter drilled concrete piers (caissons) embedded in bedrock. Two 11'-6" by 12'-6" by 8'-6" valve pits are located partially underneath and on opposite (i.e., north and south) sides of the mat foundation. The south valve pit is for ANO-1 and the north valve pit serves ANO-2. A 5'-0" high reinforced concrete wall surrounds the lower portion of the Q-CST to protect against loss due to external missile, assuring an adequate water supply will be available for the emergency feedwater system until transfer to the assured source, which is service water. The 1'-6" thick missile wall is keyed and integral to the Q-CST foundation mat. Category 1 structures have been determined to be within the scope of 10CFR54.4(a)(1).

Emergency Diesel Fuel Oil Storage Tank Vault

The emergency diesel fuel oil storage tank vault is a rigid reinforced concrete box structure located on the northwest side of the reactor building. It contains four diesel fuel storage tanks partitioned into separate rooms to provide protection against fire or flooding. The walls are designed to withstand hydrostatic loading over their full height. The structure has a mat foundation founded on rock. The vault is anchored to rock and has ventilation openings above flood elevation. The outside door is of watertight construction. The diesel fuel vault is a category 1 structure that is within the scope of 10CFR54.4(a)(1).

Bulk Fuel Oil Storage Tank Foundation

The bulk fuel oil storage tank is a 180,000 gallon, common storage tank for the on-site emergency AC power system and other systems such as the startup boiler, as discussed in SAR Section 9.5.4.2.

It has a non-Q, category 2 foundation and is not part of the safety-related fuel oil supply/storage associated with the on-site emergency AC power system. Therefore, the required independence of the AAC power system is maintained. The fuel level in the bulk fuel oil storage tank is administratively controlled to maintain a minimum of 4-1/2 days of fuel for the AAC generator at all times. The required minimum level is established considering other users that could be operable at the same time. However, the foundation is required to support the tank; therefore, the bulk fuel oil storage tank foundation has been determined to be within the scope of 10CFR54.4(a)(2).

Alternate AC Diesel Generator Building Foundation

The alternate AC diesel generator building is north of, and adjacent to, the north side berm of the bulk fuel oil storage tank. It is a seismic category 2 structure designed and built to the UBC (Reference 2.4-7). With the exception of the power distribution switchgear, major components of the AAC diesel generator are located in this building. It is a reinforced concrete slab, founded on grade beams supported by drilled in piers (caissons). The building is divided into an electrical equipment area, which also serves as the local operations station, and an engine room. This building houses the engine generator set, fuel oil transfer pump, fuel oil day tank, air start system, engine generator control cabinets, HVAC, and fire protection systems. The AAC system is designed, constructed, tested and maintained as a non-Q system conforming to augmented QA requirements based on NRC Regulatory Guide 1.155, "Station Blackout." Since the building foundation is required to support the alternate AC diesel generator, it has been determined to be within the scope of 10CFR54.4(a)(2).

Category 1 Electrical Manholes

The seismic category 1 electrical manholes are placed at various locations within the plant site. They are relatively small reinforced concrete structures founded either on natural soil or backfill materials. They are surrounded by backfill material and located partially underground. An access opening in the top slab, at grade level, is provided with a missile resistant reinforced concrete or carbon steel cover. The reinforced concrete foundations of these structures provide a fixed support for the walls that transmits loads to them. Since these structures are relatively small, relatively light loads are transmitted to the natural soils or backfill materials. Their foundations are completely independent of each other and the foundations of other structures. The category 1 electrical manholes are within the scope of 10CFR54.4(a)(1).

Borated Water Storage Tank Foundation

The BWST rests on a concrete slab that is part of the category 1 auxiliary building. The BWST is located on the roof of the boron holdup tank vault, which is subdivided by concrete walls into four separate areas. The roof slab requires approximately two feet in thickness to meet the tank structural requirements.

However, the biological shielding requirements governed the tank vault ceiling and final construction determined that a 4-foot thickness would be appropriate. The slab was designed as a two-way slab and the steel was sized appropriately for the application. A small ring wall, filled with oiled sand, was placed on the top of the concrete slab to separate the tank bottom from the top of the concrete and to provide a small slope for tank drainage purposes. Since the concrete foundation width and thickness is much larger than required for tank support, the slab is actually closer to a rigid mat foundation than to a conventional ring wall. The BWST foundation is within the scope of 10CFR54.4(a)(1).

The intended functions of the above structures components were determined by reviewing information contained in the SAR and ANO-1 engineering documents, as well as NEI 95-10 (Reference 2.4-1). The aboveground/underground yard structures fulfill the following intended functions.

- Provide structural support or functional support to safety-related equipment
- Provide shelter or protection to safety-related equipment
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas
- Serve as missile (internal or external) barriers
- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide protective barriers for internal flood event

A listing of the aboveground/underground yard structures components and unique commodities subject to an aging management review, and their intended functions, is provided in Table 3.6-7.

2.4.6.2 Bulk Commodities

Bulk commodities are structural members or items that support or protect various in-scope system components or equipment, and are common to two or more structures. Bulk commodities meet the criteria of 10CFR54.4(a)(1), 10CFR54.4(a)(2), or 10CFR54.4(a)(3). In-scope structures with common bulk commodities include the reactor building (including reactor building internals), auxiliary building, intake structure, diesel fuel vault, BWST foundation, Q-CST foundation, and pipe trenches. Although the turbine building itself is not within the scope of license renewal, some bulk commodities (fire wrap banding, fire damper mountings, fire hose reels, fire wraps, and fire stops) within the turbine building are in-scope. These are addressed along with those for the in-scope structures' bulk commodities. Bulk commodities fulfill the following intended functions.

- Provide structural support and functional support to safety-related equipment
- Provide shelter or protection to safety-related equipment (including radiation shielding)
- Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas
- Serve as missile (internal or external) barriers

- Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions
- Provide protective barriers for internal flood event
- Provide protective barriers for external flood event

A listing of passive, long-lived, bulk commodities subject to an aging management review is provided in Table 3.6-8. Bulk commodities are grouped based on materials of construction, with sub-materials indicated as appropriate. Structural intended functions by commodity are also listed. The construction materials for bulk commodities are steel, threaded fasteners, concrete (excluding prestressed concrete), fire barriers, elastomers, and Teflon. There are no bulk commodities associated with the material group earthen structures.

2.4.7 References for Section 2.4

2.4-1 NEI 95-10, "*Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule*," Revision 0, Nuclear Energy Institute, March 1996.

2.4-2 ASTM A36, "*Standard Specification for Carbon Structural Steel*," American Society for Testing and Materials.

2.4-3 ASTM A516, "*Standard Specification for Pressure Vessel Plates, Carbon Steel, for Moderate-and Lower-Temperature Service*," American Society for Testing and Materials.

2.4-4 ASME *Boiler and Pressure Vessel Code*, American Society of Mechanical Engineers.

2.4-5 ASME *Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Power Plant Components," American Society of Mechanical Engineers.

2.4-6 ASTM A300, "*Specification for Notch Toughness Requirements for Normalized Steel Plates for Pressure Vessels*," American Society for Testing and Materials.

2.4-7 Uniform Building Code, 1967 Edition.

2.5 Electrical and Instrumentation and Controls System Scoping and Screening Results

2.5.1 Purpose and Scope

The purpose of this review is to identify electrical SSCs at ANO-1 that are subject to an aging management review in accordance with 10CFR Part 54 in order to address aging concerns and manage aging effects during the period of extended operation. This process consists of two steps. The first is scoping to determine which structures and systems must be included in the license renewal process. The second step is screening to determine which components and structures of the included SSCs require an aging management review. The scoping process is discussed in Section 2.5.2 and the screening is discussed in Section 2.5.3.

2.5.2 Scoping of Electrical SSCs

The 10CFR Part 54 regulation requires a scoping of SSCs. SSCs are to be included in the license renewal process if they are.

- safety-related,
- non safety-related, but whose failure could prevent satisfactory accomplishment of a safety function, or
- relied on for compliance with Appendix R, EQ, PTS, ATWS, or station blackout.

Section 2.1 provides a discussion of the scoping process at a system level and Table 2.2-1 indicates those systems containing electrical components that are in the scope of license renewal. Additional information on electrical systems required for certain regulated events is provided herein.

2.5.2.1 EQ SSCs

Safety-related components that must continue to operate following accidents and HELBs and that are located in harsh environments resulting from that accident or HELB, are controlled as part of the EQ Program. The EQ Program tracks both components with individual equipment numbers and generic components used throughout the plant (such as cables). Because the EQ Program addresses aging of components in its scope, it is an important program to support license renewal. The harsh environments analyzed for ANO-1 are in the reactor building and in a number of rooms in the auxiliary building. Components included in the EQ Program are in the scope of license renewal per 10CFR Part 54. The detailed discussion of the EQ Program and the components covered by the EQ Program is contained in Section 4.4.

2.5.2.2 ATWS Electrical SSCs

In 1990, ANO-1 installed a DROPS/DSS for a diverse reactor trip and a DROPS/AMSAC for a backup actuation of EFW and a diverse main turbine trip. These systems place ANO-1 in compliance with 10CFR50.62 and provide plant protection in the event the reactor protection system fails to perform its function during an ATWS event. These are small, non-Q, self-contained microprocessor based systems with signal isolators connected to RCS pressure, nuclear instrumentation reactor power, and main feedwater flow signals. Trip relays are provided for interfacing with the plant components.

The electronics are considered active and the entire system is periodically calibrated and tested to verify proper operation. The electrical components in the DROPS/DSS and the DROPS/AMSAC are in the scope of license renewal. The aging management review also includes the cabling associated with the field sensors (pressure, flow, and reactor power) that supply inputs to the DROPS/DSS and the DROPS/AMSAC through signal isolators.

2.5.2.3 Station Blackout Electrical SSCs

In order to meet the requirements of 10CFR50.63, Entergy Operations installed a 4400-kW diesel generator in a separate structure that is totally independent of the other emergency power sources and their auxiliaries. The system is referred to as the alternate AC diesel generator or as the station blackout diesel. The diesel generator can be manually started within 10 minutes of a station blackout and used to power the class 1E electrical busses of both ANO units. The AAC diesel generator has its own air start system, fuel oil transfer pump, day tank, cooling, and lube oil subsystems. The AAC diesel generator is an active component, and is periodically tested to verify operability. The electrical components of the AAC diesel generator that supply the Class 1E busses are included in the scope of license renewal.

2.5.3 Screening of Electrical SSCs

As part of the integrated plant assessment for license renewal, only systems, structures, and components that are classified as long-lived and passive and which are within the scope of 10CFR Part 54 are subject to an aging management review. Active SSCs and those identified as having a periodic replacement schedule are not subject to an aging management review. ANO-1 participated in an industry wide initiative coordinated by NEI that developed a generic commodity evaluation methodology. The passive long-lived electrical components at ANO-1 were categorized using NEI 95-10 (Reference 2.5-1), Appendix B as a guide. In accordance with the NEI categorization, this screening identifies the following passive electrical components that are generic to ANO-1 systems: splices, connectors, terminal blocks, and cables. Splices, connectors, and terminal blocks are sometimes lumped together in the category of electrical connections.

The passive electrical components included in the aging management review are the separate electrical components that are not sub-components of a larger complex assembly. For example, the wiring, terminal blocks, and connectors located internal to a breaker cubicle are sub-components of the breaker. Because the breaker is an active component not subject to an aging management review, the subcomponents are not within the scope of this review.

2.5.3.1 Connectors

A connector is usually considered to be the plug and socket arrangement that allows an easy disconnection and reconnection of the electrical component. For the purpose of the ANO-1 LRA, cable splices, cable couplers, and insulating tape used in splices are also included in the scope of review since these are passive components utilized in the connection of cables that may not be evaluated as part of a larger component.

2.5.3.2 Terminal Blocks

The terminal blocks at ANO-1 are solid section blocks that are phenolic block molded and are capable of withstanding considerable temperature and radiation exposures. Terminal blocks that are not sub-components of larger active assemblies are in the scope of this review.

2.5.3.3 Cables

An insulated cable is an assembly of a single electrical conductor (wire) with an insulation covering or a combination of conductors insulated from one another having overall coverings. Cable connections are used to connect the cable conductors to other cables or electrical devices and include connectors, splices, and terminal blocks. Cables in the scope of this review are those that are separate components and not part of some larger complex assembly.

2.5.4 Electrical Components Not in the Scope of License Renewal or Not Subject to Aging Management Review

A brief discussion is provided for certain electrical components at ANO-1 which are not in the scope of license renewal or are not subject to an aging management review.

2.5.4.1 Electrical Bus

Electrical buses at ANO-1 are not in the scope of license renewal or are not subject to an aging management review due to the fact that they are either part of a larger complex assembly or they are not safety-related. The isolated-phase bus that connects the main generator to the main transformers is not safety-related. The switchyard bus is likewise not safety-related. Some safety-related bus is contained within the safety-related 4.16kV switchgear, however, this bus is considered to be part of a larger complex assembly containing bus, breakers, relays, wiring and controls. Switchgear is classified as being active by 10CFR Part 54 and NEI 95-10.

2.5.4.2 Insulators

Electrical insulators associated with the ANO-1 switchyard are not in the scope of license renewal since they are not safety-related. Other insulators found in the plant are either not safety-related or are part of a larger complex assembly.

2.5.4.3 Transmission Conductor

Transmission conductors at ANO-1 are used in non safety-related applications. Therefore, they are not in the scope of license renewal.

2.5.5 References for Section 2.5

2.5-1 NEI 95-10, "*Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule*," Revision 0, Nuclear Energy Institute, March 1996.

3.0 AGING MANAGEMENT REVIEW RESULTS

This section describes the results of the aging management reviews of the components and structures, identified in Section 2.0, that require aging management reviews. Specifically, this section:

- provides references to the descriptions of common aging management programs (Section 3.1),
- identifies the components and structures subject to aging management review and their intended functions,
- describes, or references, the processes used to identify aging effects requiring management (Appendix C describes the process for identifying aging effects associated with non-Class 1 mechanical components, which encompasses engineered safeguards, auxiliary system, and steam and power conversion system components),
- discusses the materials and environments which result in aging effects,
- identifies the aging effects requiring management,
- describes industry and operating experience with respect to the applicable aging effects, and
- lists the aging management programs that will manage the identified aging effects.

This section does not describe the aging management programs nor discuss how the programs will manage the identified aging effects. Instead, Appendix B describes these programs and provides the information necessary to demonstrate that the identified aging effects will be adequately managed.

3.1 Common Aging Management Programs

3.1.1 Chemistry Monitoring

This information is contained in Section 4.7 of Appendix B.

3.1.2 Quality Assurance

This information is contained in Section 2.0 of Appendix B.

3.1.3 Structure and System Walkdowns

This information is contained in Sections 4.16 of Appendix B.

3.2 REACTOR COOLANT SYSTEM

3.2.1 Description of the Process to Identify the Aging Effects Requiring Management for Reactor Coolant System Components

RCS components within the scope of license renewal that require aging management review are identified in Section 2.3. Their intended functions are identified in Table 3.2-1. Mechanical and structural components of the RCS include:

- RCS piping and letdown coolers
- Pressurizer
- Reactor vessel
- Reactor vessel internals
- Once-through steam generators
- Reactor coolant pumps
- Control rod drive mechanism pressure boundary

Entergy Operations, representing ANO-1, participated in a BWOG effort that developed a series of topical reports to demonstrate that the aging effects for RCS components are adequately managed for the period of extended operation under a renewed license. The following BWOG topical reports applicable to the ANO-1 RCS have been approved by the NRC.

- BAW-2243A , Reactor Coolant System Piping (Reference 3.2-1)
- BAW-2244A, Pressurizer (Reference 3.2-2)
- BAW-2251A, Reactor Vessel (Reference 3.2-3)
- BAW-2248A, Reactor Vessel Internals (Reference 3.2-4)

NRC-approved reports may be incorporated by reference provided the conditions of approval contained in the safety evaluation of the specific report are met. These reports have been incorporated by reference into the ANO-1 LRA as discussed in Section 2.3.1.2. Time-limited aging analyses associated with components of the RCS are discussed in Section 4.0.

Determination of the aging effects applicable to RCS components begins with identification of the potential aging effects defined in industry literature. From this set of potential aging effects, the materials, operating environment, and operating stresses define the aging effects requiring management for each component that is subject to aging management review. Aging effects requiring management are then validated by a review of industry and ANO-1 operating experience, to provide assurance that all aging effects requiring management are identified.

The review to identify the aging effects requiring management for RCS components considers the following potential aging effects that have been identified by reviewing industry literature.

- Loss of material
- Cracking (initiation and growth)—Cracking due to fatigue is a time-limited aging analysis and is addressed in Section 4.3.
- Reduction of fracture toughness—Reduction of fracture toughness of the reactor vessel beltline region due to neutron embrittlement is a time-limited aging analysis and is addressed in Section 4.2.
- Loss of mechanical closure integrity of bolted closures
- Dimensional changes by void swelling
- Mechanical distortion
- Fouling

The determination of aging effects requiring management considers the materials, environment, and stresses of ANO-1 components. The aging effects requiring management for the RCS components are discussed in the following sections.

3.2.2 RCS Piping and Letdown Coolers

Reactor coolant system piping subject to aging management review is identified in Section 2.3.1.3. As described in Section 2.3.1.3, ANO-1 is bounded by BAW-2243A (Reference 3.2-1) with regard to RCS piping and associated materials of construction. The approach for identifying aging effects requiring management for the RCS piping is described in Section 3.2.1. RCS items not within the scope of BAW-2243A that are evaluated in this section include instrumentation tubing, RTE thermowells, and the letdown coolers.

Environment and Stress

The operating environment of the ANO-1 RCS piping is consistent with that described in BAW-2243A, Section 3.1.1. The operating environment for the instrumentation tubing and the RTE thermowells is the same as for the RCS piping. The Primary Chemistry Monitoring Program includes specifications to periodically monitor the primary coolant. Limitations are established on dissolved oxygen, halides and other impurities. Corrective actions are taken in the event the primary coolant parameters are out of specification. RCS chemistry is maintained in accordance with the Primary Chemistry Monitoring Program.

Reactor coolant system piping is designed to accommodate service loadings (i.e., levels A through D); however, operation under level A and B service conditions contribute to normal aging stresses for the piping. ANO-1 has not been subjected to a level C or D event. Therefore, the ANO-1 RCS piping is bounded by BAW-2243A with respect to the qualitative assessment of stress.

The operating environments for the letdown coolers include primary water chemistry on the tube side and treated water from the intermediate cooling water on the shell side. The letdown coolers are designed to accommodate service loads defined by ASME Section III-C on the tube side and ASME Section VIII on the shell side.

Aging Effects Requiring Management

The aging effects applicable to the ANO-1 RCS piping are consistent with those described in Section 3 of BAW-2243A since ANO-1 is bounded by the generic report with respect to materials of construction, operating environment, level A and B service conditions, and operating experience. The results of the aging effects review are contained in BAW-2243A. The aging effects requiring management for the RCS piping are summarized in Table 3.2-1.

Reduction of fracture toughness for RCS valves fabricated from CASS was identified as an applicable aging effect in BAW-2243A. No Class 1 piping at ANO-1 is fabricated from CASS. The assessment of reduction of fracture toughness of RCS valves required evaluation of the plant-specific material forms and temperature environment of the valves that form the Class 1 boundary at ANO-1. Class 1 CASS valves were identified and an assessment was made to determine if the valves are exposed to elevated temperatures during power operation. A threshold temperature of 482°F (350°C) is a conservative limit below which reduction of fracture toughness is not an applicable aging effect. The

ANO-1 evaluation found only three Class 1 valves fabricated from CASS that are exposed to operating temperatures above 482°F and susceptible to reduction of fracture toughness: two 2 1/2-inch valves in the letdown line and the 2 1/2-inch pressurizer spray line block valve. The saturated lower bound fracture toughness of these valve bodies is approximately equal to the fracture toughness of austenitic weldments in pipes made using the submerged arc welding process (BAW-2243A, Section 4.2). Therefore, volumetric inspections of stainless steel piping welded joints between 1-inch and 4-inch NPS in the letdown piping or the pressurizer spray line piping, as defined by ANO-1 risk-informed ISI program for Examination Category B-J, will bound the subject valves since valve bodies have thicker walls and lower stresses than adjacent piping.

Items not within the scope of BAW-2243A are evaluated as follows. Instrumentation tubing and RTE thermowells are fabricated from austenitic stainless steel and are subject to the same environment as the other stainless steel piping in the RCS. Aging effects requiring management for the instrumentation tubing and RTE thermowells will be consistent with aging effects identified for stainless steel piping.

Aging effects requiring management for the letdown coolers include cracking of the tubes by fatigue and stress corrosion cracking on the tube surface exposed to intermediate cooling water, loss of material of tubes due to vibration, loss of material from the interior of the shell by corrosion, loss of material of the external surface of the heat exchanger by boric acid wastage, and loss of mechanical closure integrity.

Industry Experience

The industry experience for RCS piping is described in Section 3 of BAW-2243A.

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for the RCS piping. This review included the station information management system, condition reporting system, and licensing event database. The review of ANO-1 operating experience identified five leaks associated with RCS small bore piping (1½" drain off RCP 32B in 1989-90, a leak at HPI/MU vent line in 1989, pinhole leaks at coupling adjacent to a decay heat valve in 1993, core flood tank drain in 1996 and a circumferential crack on a HPI/MU drain in 1998). All of these leaks and cracks were caused by vibrational fatigue. This cracking was due to design problems, which have since been corrected. The corrective actions taken resolved the design problem and ensured this problem would be addressed in subsequent design work.

Loss of material by boric acid wastage has previously been identified on the discharge cold leg HPI nozzle region. This condition was corrected. The ANO-1 Boric Acid Corrosion Prevention Program will monitor this type of aging effect and ensure appropriate corrective action.

Industry operating experience indicated that additional elements of bolting maintenance practices should be considered, such as personnel training, installation and maintenance procedures, plant-specific bolting degradation history, and corrective measures. The NRC captured the lessons from this experience in IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," and Generic Letter 91-17, "Bolting Degradation or Failure in Nuclear Power Plants," and directed each licensee to assure that these lessons were being incorporated at their plant.

ANO-1 has taken actions to improve bolting practices in accordance with NRC Bulletin 82-02 and Generic Letter 91-17. Guidelines developed for preparing, installing and tightening threaded fasteners are applied to maintenance activities that involve threaded fasteners. In response to GL 91-17, training based on review of the EPRI bolting reports was provided to the appropriate departments. The training implemented as a result of GL 91-17 is captured in the "Bolting and Torquing Activities," program described in Appendix B. This program ensures proper bolt material selection and bolting preload control as well as proper maintenance procedures and practices. These actions resolve the bolting concerns of NRC Bulletin 82-02 and Generic Letter 91-17 for ANO-1.

ANO-1 Technical Specification leakage limits, ASME Section XI bolting examination (Examination Categories B-G-1 and B-G-2), the Boric Acid Corrosion Prevention Program, and continuation of routine ANO-1 maintenance practices reviewed under IE Bulletin 82-02 and GL 91-17 will assure management of loss of mechanical closure integrity for all bolted closures in the RCS.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the RCS piping and the letdown coolers are summarized in Table 3.2-1. These aging effects must be adequately managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. These aging effects requiring management will be adequately managed by the following existing programs, which are described in Appendix B.

- Boric Acid Corrosion Prevention Program
- Primary Chemistry Monitoring Program
- ASME Section XI Inservice Inspection Program, Subsection IWB (as supplemented by Code Case N-560 for Examination Category B-J welds)
- Leakage Detection in Reactor Building
- Alloy 600 Aging Management Program
- Bolting and Torquing Activities
- Small Bore Piping and Small Bore Nozzles Inspections

3.2.3 Pressurizer

The pressurizer is within the scope of license renewal as discussed in Section 2.3.1.4. The following pressurizer items are subject to aging management review.

- Pressurizer vessel
- Nozzles
- Other pressure retaining items
- Bolted closures
- Integral attachments
- Immersion heaters

As described in Section 2.3.1.4, ANO-1 is bounded by the BWOG topical report with regard to the pressurizer.

Environment and Stress

The operating environment of the ANO-1 pressurizer is consistent with that described in Section 3 of BAW-2244A (Reference 3.2-2). The ANO-1 Primary Chemistry Monitoring Program includes specifications to periodically monitor the primary coolant. Limitations are established on dissolved oxygen, halides and other impurities. Corrective actions are taken in the event primary coolant parameters are out of specification. ANO-1 RCS chemistry is maintained in accordance with the ANO-1 Primary Chemistry Monitoring Program.

The pressurizer is designed to accommodate service loadings (i.e., levels A through D); however, operation under level A and B service conditions contribute to the normal aging stresses for the pressurizer. ANO-1 has not been subjected to a level C or D event. Therefore, the ANO-1 pressurizer is bounded by BAW-2244A with respect to the qualitative assessment of stress.

Aging Effects Requiring Management

The aging effects requiring management for the ANO-1 pressurizer are consistent with those described in Section 3 of BAW-2244A. The results of the aging effects review are contained in BAW-2244A. The aging effects requiring management for the pressurizer are summarized in Table 3.2-1.

Industry Experience

The industry experience for the pressurizer is described in Section 3 of BAW-2244A.

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for the pressurizer. This review included a search for instances of pressurizer aging at ANO-1 using the station information management system, condition reporting system, and licensing event database. From this review, no aging effects requiring management were identified beyond those identified in BAW-2244A.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the pressurizer are summarized in Table 3.2-1. These aging effects must be adequately managed so that the intended function of the pressurizer listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. The aging effects requiring management will be adequately managed by the following existing programs that are described in Appendix B:

- Boric Acid Corrosion Prevention Program
- Primary Chemistry Monitoring Program
- ASME Section XI Inservice Inspection Program, Subsection IWB (as supplemented by Code Case N-560 for Examination Category B-J welds)
- Leakage Detection in Reactor Building
- Alloy 600 Aging Management Program
- Bolting and Torquing Activities

In addition to the above, the following new activity has been identified for license renewal and is described in Appendix B.

- Pressurizer Examinations

3.2.4 Reactor Vessel

The reactor vessel is within the scope of license renewal as discussed in Section 2.3.1.5. The following reactor vessel items are subject to aging management review.

- Shell and closure head
- Nozzles
- Interior attachments
- Bolted closures

As described in Section 2.3.1.5, ANO-1 is bounded by BAW-2251A (Reference 3.2-3) with regard to reactor vessel items and associated materials of construction. The approach for identifying the aging effects requiring management is described in Section 3.2.1.

Environment and Stress

The operating environment of the ANO-1 reactor vessel is consistent with that described in Section 3 of BAW-2251A. The ANO-1 Primary Chemistry Monitoring Program includes specifications to periodically monitor the primary coolant. Limitations are established on dissolved oxygen, halides and other impurities. Corrective actions are taken in the event primary coolant parameters are out of specification. RCS chemistry is maintained in accordance with the ANO-1 Primary Chemistry Monitoring Program.

The reactor vessel is designed to accommodate service loadings (i.e., levels A through D); however, operation under level A and B service conditions contribute to the normal aging stresses for the reactor vessel. ANO-1 has not been subjected to a level C or D event. Therefore, the ANO-1 reactor vessel is bounded by BAW-2251A with respect to the qualitative assessment of stress.

Aging Effects Requiring Aging Management

The aging effects applicable to the ANO-1 reactor vessel are consistent with those described in BAW-2251A since ANO-1 is bounded by the generic report with respect to materials of construction, operating environment, level A and B service conditions, and operating experience. The aging effects requiring management for the reactor vessel are summarized in Table 3.2-1.

Industry Experience

The industry experience for the reactor vessel is described in Section 3 of BAW-2251A.

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for the reactor vessel. This review included a search for instances of aging of the reactor vessel at ANO-1 using the station information management system, condition reporting system, and licensing event database. From this review, no aging effects requiring management were identified beyond those identified in BAW-2251A.

Conclusion

During the review of industry information, NRC generic communications, and operating experience, no additional aging effects beyond those discussed in this section were identified for ANO-1. The aging effects requiring management for the reactor vessel are summarized in Table 3.2-1. These aging effects must be adequately managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. The aging effects requiring management will be adequately managed by the following existing programs, which are described in Appendix B.

- Primary Chemistry Monitoring Program
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program
- ASME Section XI Inservice Inspection Program, Subsection IWB
- Leakage Detection in Reactor Building
- Reactor Vessel Integrity Program
- Boric Acid Corrosion Prevention Program
- Alloy 600 Aging Management Program
- Bolting and Torquing Activities

3.2.5 Reactor Vessel Internals

The reactor vessel internals are within the scope of license renewal as discussed in Section 2.3.1.6. The following reactor vessel internal items are subject to aging management review.

- Plenum assembly
- Core support shield assembly
- Core barrel assembly
- Lower internals assembly
- Reactor vessel level monitoring system probe supports
- Remaining portions of the surveillance specimen holder tubes
- Thermal shield and thermal shield upper restraint

As described in Section 2.3.1.6, ANO-1 is bounded by BAW-2248A (Reference 3.2-4) with regard to reactor vessel internal items within the first four groups defined above. The RVLMS probe supports, surveillance specimen holder tubes, and thermal shield and thermal shield upper restraint are not within the scope of BAW-2248A but are within the scope of license renewal and subject to aging management review for ANO-1.

<u>Environment and Stress</u>

The operating environment, or chemistry of the fluid in contact with the ANO-1 reactor vessel internals, is maintained consistent with that described in Section 3 of BAW-2248A. The ANO-1 Primary Chemistry Monitoring Program includes specifications to periodically monitor the primary coolant. Limitations are established on dissolved oxygen, halides, and other impurities. Corrective actions are taken in the event primary coolant parameters are out of specification. ANO-1 RCS chemistry is maintained in accordance with the ANO-1 Primary Chemistry Monitoring Program.

The reactor vessel internals are designed to accommodate service loadings (i.e., levels A through D); however, operation under level A and B service conditions contribute to the normal aging stresses for the reactor vessel internals. ANO-1 has not been subjected to a level C or D event. Therefore, ANO-1 is bounded by BAW-2248A with respect to the qualitative assessment of stress.

<u>Aging Effects Requiring Management</u>

The aging effects requiring management of the ANO-1 reactor vessel internals are consistent with those described in Section 3 of BAW-2248A for reactor vessel internal items within the first four groups listed above. The results of the aging effects review are contained in BAW-2248A. Items specific to ANO-1 and not within the scope of BAW-2248A are evaluated below.

The reactor vessel internals items that support the RVLMS probes are constructed from austenitic stainless steel and the aging effects requiring management for these items are consistent with other stainless steel items in the plenum assembly (i.e., cracking and loss of mechanical closure integrity caused by stress relaxation of the RVLMS brazement guide assembly j-bolt and nut).

The thermal shield that surrounds the core barrel and the thermal shield upper restraint are constructed from austenitic stainless steel. The aging effects requiring management for these items, consistent with those identified in BAW-2248A for the core barrel assembly, are cracking and reduction of fracture toughness. The upper surveillance specimen holder tube assembly and some of the brackets and their bolts are still installed at ANO-1. These items are fabricated from austenitic stainless steel and the aging effects requiring management include cracking and loss of mechanical closure integrity by stress relaxation of the bolting.

The aging effects requiring management for the reactor vessel internals are summarized in Table 3.2-1.

Industry Experience

The industry experience for the reactor vessel internals is described in Section 3 of BAW-2248A. Subsequent to the issuance of BAW-2248A, NRC issued Information Notice 98-11, "Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants," on March 25, 1998. Information Notice 98-11 discusses cracking of reactor vessel internal baffle former bolts found at several foreign pressurized water reactors and includes, among other information, a brief discussion of the current and planned activities of the BWOG to address the potential for cracking of baffle bolts in domestic B&W plants.

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for reactor vessel internals. This review included a search for instances of reactor vessel internals aging at ANO-1 using the station information management system, condition reporting system, and licensing event database. One issue identified in this review was cracking of the thermal shield bolting and core barrel bolting as discussed in Section 3.5.4 of BAW-2248A. The only other event of note was the surveillance specimen holder tube failures. This early failure was due to a design flaw and was not related to aging. From this review, no aging effects requiring management were identified beyond those identified in BAW-2248A.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the reactor vessel internals are summarized in Table 3.2-1. These aging effects must be adequately managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. The aging effects requiring management will be managed by the following existing programs, which are described in Appendix B.

- ASME Section XI Inservice Inspection Program, Subsection IWB
- Primary Chemistry Monitoring Program

In addition to the above, the following new program has been identified for license renewal and is described in Appendix B.

- Reactor Vessel Internals Aging Management Program

3.2.6 Once-Through Steam Generators

The once-through steam generators are within the scope of license renewal as discussed in Section 2.3.1.7. The following once-through steam generator items are subject to aging management review.

- Primary pressure boundary: hemispherical heads, support skirt transition ring, primary nozzles, Alloy 600 drain nozzle, bolted closures, tubesheets, tubes, plugs, sleeves, bolted closures, and integral attachments inspected in accordance with ASME Section XI, Subsection IWB.
- Secondary pressure boundary: shell, tubesheets, and integral attachments, steam outlet nozzles, main feedwater nozzles, emergency feedwater nozzles, feedwater header and riser piping, instrumentation nozzles, vent nozzles, drain nozzles, temperature sensing connections, bolted closures and integral attachments inspected in accordance with ASME Section XI, Subsection IWC.

The following is a description of the aging effects applicable to the once-through steam generators. The approach for identifying the aging effects requiring management is described in Section 3.2.1.

Environment and Stress

The ANO-1 Chemistry Control Programs include specifications to periodically monitor the primary coolant and the secondary coolant. Limitations are established for the primary coolant on dissolved oxygen, halides and other impurities. Limitations are established on specific impurities in the secondary coolant. ANO-1 primary side chemistry and secondary side chemistry are maintained by the ANO-1 Chemistry Control Programs.

The once-through steam generator is designed to accommodate all service loadings (i.e., levels A through D); however, operation under level A and B service conditions contribute to the normal aging stresses for the once-through steam generator items. ANO-1 has not been subjected to a level C or D event.

Aging Effects Requiring Aging Management for Primary Pressure Boundary Items

Potential aging effects that may be applicable to the items that support the primary pressure boundary include loss of material, cracking, mechanical distortion of tubes, and loss of mechanical closure integrity. Aging mechanisms that may lead to reduction of fracture toughness of once-through steam generator items include various forms of embrittlement (e.g., neutron and thermal). Neutron embrittlement is limited to the direct neutron flux of the reactor vessel beltline region and is not a concern for the once-through steam generator. Thermal embrittlement is negligible for all pressurized water reactor materials except cast austenitic stainless steel, and once-through steam generators at ANO-1 have no cast austenitic stainless steel parts.

Primary - Loss of Material Assessment

Loss of material may be due to intergranular attack, pitting, wear, erosion/corrosion, and wastage, as further discussed in the following paragraphs.

The Alloy-600 steam generator tubes are subject to loss of material due to intergranular attack, pitting, wear, or fretting, and erosion or erosion/corrosion. The plugs and sleeves installed inside the tubes are made of Alloy-600 or Alloy-690 and are less susceptible to loss of material.

Intergranular attack of steam generator tubes is characterized by a relatively uniform attack at grain boundaries over a portion of the tubing surface. Intergranular attack is caused by impurities that concentrate in steam generator secondary side crevices and sludge piles, where boiling occurs and circulation is poor. Once-through steam generator tubes are roll expanded over only a portion of the tubesheet thickness. Consequently, a crevice exists between the tubes and the tube bore hole through the tubesheets that provides the environment for intergranular attack.

Pitting is a localized corrosion mechanism that produces small holes in the metal. Low fluid velocity or stagnation is usually associated with the development of pitting. Pitting has occurred in once-through steam generator tubes.

Fretting and sliding wear of steam generator tubes at tube support locations has occurred in the industry. The forces imposed on the tubes by the secondary fluid cause high frequency vibration of the tubes and interaction with the tube support structures.

Erosion is the loss of surface metal due to the mechanical action of flowing fluid. Erosion/corrosion is the loss of material due to the combined actions of erosion by the flowing fluid and corrosion of the newly exposed base material by chemicals in the flowing fluid. Once-through steam generator tube damage has occurred due to erosion/corrosion near the fourteenth tube support plate at another B&W operating plant but has not been observed at ANO.

The external surfaces of the primary pressure boundary components are subject to loss of material due to boric acid wastage. The leakage of primary coolant through adjacent bolted closures, and the subsequent evaporation and concentration of boric acid, could lead to the presence of a boric acid slurry on the bolting and external surfaces of the vessel. The boric acid slurry could cause loss of material of the external surfaces. Therefore, loss of material is an aging effect requiring management for the external surfaces of the once-through steam generators at ANO-1.

Primary - Cracking Assessment

Because of the consequences of a breach of the primary system pressure boundary, cracking at welded joints is considered an aging effect requiring management for items fabricated from carbon steel and low-alloy steel. Welded joints are the more susceptible locations due to the various constituent zones within the joint, resulting in slight variations in residual stresses and mechanical properties. Cracking at welded joints is an aging effect requiring management for clad low-alloy steel heads, clad low-alloy tubesheets, and clad carbon steel nozzle forgings. In addition, cracking of the Alloy-600 and Alloy-690 tubes, plugs, sleeves, and drain nozzle by primary water stress corrosion cracking is an aging effect requiring management.

Primary - Mechanical Distortion Assessment

Steam generator tubes have been found to suffer a form of distortion called denting. Denting is the mechanical deformation of tubes due to corrosion of the tube support structures. The corrosion product is mostly magnetite. Because magnetite is less dense than the support structure, the corrosion products occupy more volume than the original base metal. As more magnetite forms, it expands into the crevice between the tube and the support structure. Eventually the crevice becomes completely filled and any further corrosion causes the tube to deform or the support structure to fracture. Therefore, mechanical distortion is an aging effect requiring management for the once-through steam generator tubes at ANO-1.

Primary - Loss of Mechanical Closure Integrity Assessment

Stress relaxation and corresponding loss of preload may lead to localized leakage of reactor coolant and a loss of mechanical closure integrity. This localized leakage of borated coolant may cause corrosive attack and loss of material of bolting, adjacent flange surfaces, and surfaces below the bolted connection leak source. Loss of mechanical closure integrity is associated with the condition of the closure bolting and bolting surfaces. Aging effects relevant to the mechanical closure bolting are cracking, loss of bolt preload due to stress relaxation, and loss of material for low-alloy steel bolting due to boric acid wastage. Loss of mechanical closure integrity is an aging effect requiring management for the once-through steam generators at ANO-1.

Aging Effects Requiring Management for Secondary Pressure Boundary Items

Potential aging effects applicable to the items that support the secondary pressure boundary include loss of material, cracking, and loss of mechanical closure integrity. Reduction of fracture toughness is not an aging effect requiring management for the secondary pressure boundary items.

Secondary - Loss of Material Assessment

The external surfaces of the secondary pressure boundary components are subject to loss of material due to boric acid wastage. The leakage of primary coolant through adjacent bolted closures, and the subsequent evaporation and concentration of boric acid, could lead to the presence of a boric acid slurry on the bolting and external surfaces of the secondary side of the steam generator. The boric acid slurry could cause loss of material of the external surfaces.

Erosion is the loss of surface metal due to the mechanical action of flowing fluid. Erosion/corrosion is the loss of material due to the combined actions of erosion by the flowing fluid and corrosion of the newly exposed base material by chemicals in the flowing fluid. The steam outlet nozzles may be affected due to the high fluid velocity through the nozzles. Erosion of secondary manways and inspection ports may occur as a result of leakage through bolted closures. Therefore, loss of material is an aging effect requiring management for the once-through steam generators at ANO-1.

Secondary - Cracking Assessment

Similar to the discussion above for primary pressure boundary welded joints, cracking at welded joints of the secondary pressure boundary is considered an aging effect requiring management for license renewal at ANO-1.

Secondary - Loss of Mechanical Closure Integrity Assessment

Similar to the discussion above for primary bolted connections, loss of mechanical closure integrity of secondary manways, inspection ports, and feedwater pipe flanges may occur and is considered an aging effect requiring management for license renewal. Therefore, loss of mechanical closure integrity is an aging effect requiring management for the once-through steam generators at ANO-1.

Industry Experience

In order to validate the identified aging effects requiring management, a survey of industry experience was performed. This survey included NRC generic communications, licensee event reports from nuclear power plants other than ANO-1, and NRC NUREGs. The following documents were included in this review.

- Numerous Information Notices
- IE Bulletin 79-13, "Cracking in Feedwater System Piping"
- IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- IE Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
- GL 79-20, "Information Requested on PWR Feedwater Lines"
- GL 85-02, "Staff Recommended Actions Stemming from NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity"
- GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- GL 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning"
- GL 91-17, "Generic Safety Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- GL 95-03, "Circumferential Cracking of Steam Generator Tubes"

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for the once-through steam generators. This review included a search for instances of aging at ANO-1 using the station information management system, condition reporting system, and licensing event database. No additional aging effects were identified from this review.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the once-through steam generator are summarized in Table 3.2-1.

These aging effects must be adequately managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. The aging effects requiring management will be adequately managed by the following existing programs, which are described in Appendix B:

- Boric Acid Corrosion Prevention Program
- Primary Chemistry Monitoring Program
- Secondary Chemistry Monitoring Program
- ASME Section XI Inservice Inspection Program, Subsections IWB and IWC
- Leakage Detection in Reactor Building
- Steam Generator Integrity Program
- Alloy 600 Aging Management Program
- Bolting and Torquing Activities

3.2.7 Reactor Coolant Pumps

Reactor coolant pumps are in the scope of license renewal as discussed in Section 2.3.1.8. The following reactor coolant pump items are subject to aging management review.

- Casing
- Cover
- Seal water heat exchanger
- Pressure-retaining bolting

The approach for identifying the aging effects requiring management on the reactor coolant pumps is described in Section 3.2.1.

Environment and Stress

The materials and operating environment of the reactor coolant pumps, including the bolted closures and connections, are similar to that evaluated in the RCS piping reviews (see Section 3.2.2).

The seal water heat exchangers are a double coil tube-in-tube design. The inner tube carries primary water and the outer tube carries treated water from the intermediate cooling water system.

Aging Effects Requiring Aging Management

The pump casings are constructed of cast austenitic stainless steel similar to the valve bodies evaluated in Section 3.2.2. The aging effects requiring management for the casing are cracking at welded joints and reduction of fracture toughness. The aging effects requiring management for the cover are cracking by fatigue and reduction of fracture toughness. Aging effects requiring management for the seal water heat exchangers include cracking and loss of material of the inner tube. The bolted closures and connections of the reactor coolant pump casings are made of the same material as RCS piping bolted closures and connections evaluated in Section 3.2.2 and the aging effects requiring management are cracking of the bolting material, loss of mechanical closure integrity, and loss of material.

Industry Experience

In order to validate the identified aging effects requiring management, a survey of industry experience was performed. This survey included NRC generic communications, licensee event reports from nuclear power plants other than ANO-1, and NRC NUREGs. The following documents were reviewed.

- IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants" and
- GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"

The results of the review of NRC generic communications for the RCS piping report (Reference 3.2-1) are also applicable to the reactor coolant pump. In addition, the aging effects requiring management for the reactor coolant pump casings, covers, and associated bolted closures and connections are further validated by the reviews performed and documented in the PWR RCS License Renewal Industry Report (Reference 3.2-5).

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for reactor coolant pumps. This review included a search for instances of reactor coolant pump aging at ANO-1 using the station information management system, condition reporting system, and licensing event database. From this review, no aging effects requiring management were identified beyond those identified previously in this section.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the reactor coolant pumps are consistent with those previously identified for RCS piping (see Section 3.2.2). The aging effects requiring management for the reactor coolant pumps are summarized in Table 3.2-1. These aging effects must be managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis for the period of extended operation. The aging effects requiring management will be managed by the following programs, which are described in Appendix B.

- ASME Section XI Inservice Inspection Program Subsection IWB (as supplemented by Code Case N-481 to manage reduction of fracture toughness of the pump casing) including an augmented inspection of a reactor coolant pump (visual inspection of the pressure retaining surfaces, including the cover, prior to entering the period of extended operation). The flaw tolerance evaluation used to comply with Code Case N-481 is a time-limited aging analysis and is addressed in Section 4.3.6.
- Primary Chemistry Monitoring Program
- Auxiliary Systems Chemistry Monitoring Program
- Leakage Detection in Reactor Building
- Boric Acid Corrosion Prevention Program
- Bolting and Torquing Activities

3.2.8 Control Rod Drive Mechanism Pressure Boundary

Control rod drive tube motor housings are identified in Section 2.3.1.9 as being subject to aging management review. The CRDM items subject to aging management review include.

- CRDM Motor Tube Assembly
- CRDM Closure Insert and Vent Assemblies

In addition, the RVLMS adapter flange/closure assembly components were identified as subject to aging management review in Section 2.3.1.9. The following is a description of the aging effects applicable to the control rod drive tube motor housings and RVLMS adapter flange/closure assembly. The approach for identifying the aging effects requiring management for the control rod drive tube motor housings is described in Section 3.2.1.

Environment and Stress

The chemistry of the fluid in contact with the control rod drive tube motor housings is maintained in a manner consistent with other RCS components. The ANO-1 Primary Chemistry Monitoring Program is maintained and includes specifications to periodically monitor the primary coolant. Limitations are established on dissolved oxygen, halides and other impurities. Corrective actions are taken in the event primary coolant parameters are out of specification.

The control rod drive tube motor housings are designed to accommodate service loadings (i.e., levels A through D). Operation under level A and B service conditions contribute only to the normal aging stresses for the control rod drive tube motor housings. ANO-1 has been subjected to level A and B service loadings, and not to level C or D events.

Aging Effects Requiring Aging Management

The control rod drive tube motor housings are fabricated from austenitic and martensitic stainless steels with the exception of the center section of the type B drive, which is a low-alloy steel forging clad with Alloy 82/182. The closure insert and vent assemblies and the RVLMS adapter flange assembly are fabricated from austenitic stainless steel. The aging effect requiring management for the closure insert and vent assemblies is loss of mechanical closure integrity. Aging effects requiring management for the control rod drive tube motor housings include cracking at welded joints and loss of mechanical closure integrity for the bolted connections. The aging effect requiring management for the RVLMS adapter flange assembly is cracking at welded joints. These effects are consistent with those previously identified in Section 3.2.2 for RCS piping.

Industry Experience

In order to validate the set of aging effects requiring management, a survey of industry experience was performed. This survey included NRC generic communications, licensee event reports from nuclear power plants other than ANO-1, and NRC NUREGs. From this review, no aging effects requiring management were identified beyond those identified in this section.

ANO-1 Operating Experience

ANO-1 operating experience was reviewed to validate the identified aging effects requiring management for control rod drive tube motor housings. This review included a search for instances of control rod drive mechanism aging at ANO-1 using the station information management system, condition reporting system, and licensing event database. From this review, no aging effects requiring management were identified beyond those identified in this section.

Conclusion

During the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified. The aging effects requiring management for the control rod drive tube motor housings, closure insert and vent assemblies, and RVLMS items are consistent with those previously identified for RCS piping (see Section 3.2.2). The aging effects requiring management for the control rod drive tube items subject to aging management review are summarized in Table 3.2-1. These aging effects must be managed so that the intended functions listed in Table 3.2-1 will be maintained consistent with the current licensing basis of the period of extended operation. The aging effects requiring management will be managed by the following existing programs, which are described in Appendix B.

- ASME Section XI Inservice Inspection Program, Subsection IWB
- Leakage Detection in Reactor Building
- Primary Chemistry Monitoring Program
- Bolting and Torquing Activities

3.2.9 References for Section 3.2

3.2-1 BAW-2243A, "*Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping,*" The B&W Owners Group Generic License Renewal Program, June 1996.

3.2-2 BAW-2244A, "*Demonstration of the Management of Aging Effects for the Pressurizer,*" The B&W Owners Group Generic License Renewal Program, December 1997.

3.2-3 BAW-2251A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel,*" The B&W Owners Group Generic License Renewal Program, June 1996.

3.2-4 BAW-2248A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel Internals,*" The B&W Owners Group Generic License Renewal Program, December 1999.

3.2-5 NUMARC 90-07-01, "*PWR Reactor Coolant System License Renewal Industry Report,*" Revision 1, Nuclear Management and Resource Council, May 1992.

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
RCS piping, pressurizer, RV, and OTSG	Pressure boundary	Low-alloy and clad carbon steel pressure retaining items	External-Ambient	Loss of material by boric acid wastage	Boric Acid Corrosion Prevention
Reactor Coolant System Piping					
Reactor coolant system piping , NPS ≥ 4 inches	Pressure boundary	Stainless steel clad carbon steel piping Stainless steel piping	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560 • Examination Category B-P Leakage Detection in Reactor Building
Hot leg flowmeter assembly	Pressure boundary	Stainless steel clad (alloy 82/182)	Primary water	Loss of material (carbon steel) due to potential for cracking of alloy 82/182 cladding	Primary Chemistry Monitoring Alloy 600 Aging Management
Reactor coolant system piping, NPS ≥ 4 inches	Pressure boundary	Stainless steel clad carbon steel branch connections with alloy 82/182 weld build-up	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560 • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Reactor coolant system piping, 1 inch < NPS < 4 inches	Pressure boundary	Stainless steel piping and stainless steel branch connections	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560 • Examination Category B-P • Small Bore Piping and Small Bore Nozzles Inspections Leakage Detection in Reactor Building
Reactor coolant system piping, 1 inch < NPS < 4 inches	Pressure boundary	2½-inch SS clad carbon steel HPI branch connections and safe ends with thermal sleeves	Primary water	Displacement or cracking of HPI/MU thermal sleeves Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560—augmented examination of thermal sleeve • Examination Category B-P • Small Bore Piping and Small Bore Nozzles Inspections Leakage Detection in Reactor Building
Reactor coolant system piping, 1 inch < NPS < 4 inches	Pressure boundary	Stainless steel clad carbon steel branch connections with Alloy 600 safe ends	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560 • Examination Category B-P • Small Bore Piping and Small Bore Nozzles Inspections Leakage Detection in Reactor Building Alloy 600 Aging Management

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Reactor coolant system piping, 1 inch < NPS < 4 inches	Pressure boundary	Alloy 600 branch connections	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-J as modified by Code Case N-560 • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management
Reactor coolant system piping, NPS ≤ 1 inch	Pressure boundary	Stainless steel pipe and stainless steel branch connections	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P • Small Bore Piping and Small Bore Nozzles Inspections Leakage Detection in Reactor Building
Reactor coolant system piping, NPS ≤ 1 inch	Pressure boundary	Alloy 600 branch connections	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management
Reactor coolant system valves, NPS ≥ 4 inches	Pressure boundary	Stainless steel valve bodies and bonnets	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-M-1 • Examination Category B-P Leakage Detection in Reactor Building

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Reactor coolant system valves, NPS < 4 inches	Pressure boundary	Cast austenitic stainless steel valve bodies and bonnets	Primary water	Reduction of fracture toughness	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building
Reactor coolant system bolting ≤ 2-inches diameter	Pressure boundary	Low-alloy steel valve bolting	Primary water	Cracking Loss of mechanical closure integrity Loss of material	ASME Section XI ISI-IWB • Examination Category B-G-2 • Examination Category B-P Leakage Detection in Reactor Building Bolting and Torquing Activities
Reactor coolant system valve bolting ≤ 2-inches diameter	Pressure boundary	Stainless steel valve bolting	Primary water	Cracking Loss of mechanical closure integrity	ASME Section XI ISI-IWB • Examination Category B-G-2 • Examination Category B-P Leakage Detection in Reactor Building Bolting and Torquing Activities
Letdown coolers tubes and manifold	Pressure boundary	Stainless steel	Primary water	Cracking Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building
Letdown coolers shell and end plates	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Pressurizer					
Pressurizer vessel	Pressure boundary	Stainless steel clad carbon steel	Primary water	Cracking at welded joints Cracking of cladding	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-B • Examination Category B-P Leakage Detection in Reactor Building Pressurizer Examinations
Pressurizer, full penetration welded nozzles, NPS > 1-inch	Pressure boundary	Stainless steel clad carbon steel	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-D • Examination Category B-P Leakage Detection in Reactor Building
Pressurizer, safe ends of full penetration welded nozzles, NPS > 1-inch	Pressure boundary	Alloy 600	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-F and B-J as modified by Code Case N-560 • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management
Pressurizer, pressure retaining partial penetration welds, NPS≤1-inch	Pressure boundary	Alloy 600	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P • Augmented inspection of repaired nozzle and VT-2 of other nozzles Leakage Detection in Reactor Building Alloy 600 Aging Management

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Pressurizer, dissimilar metal welds, NPS > 1-inch	Pressure boundary	Alloy 82/182	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-F and B-J as modified by Code Case N-560 • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management
Pressurizer, immersion heaters (sheaths, end plugs, and welds) and the weld that connects the immersion heaters to the diaphragm plate	Pressure boundary	Stainless steel	Primary water	Cracking	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building Pressurizer Examinations
Pressurizer integral attachments	Pressure boundary	Carbon steel	External-reactor building	Cracking at welded joints	ASME Section XI ISI-IWB • Examination Category B-H
Pressurizer bolting > 2-inches diameter	Pressure boundary	Low-alloy manway studs	External-reactor building	Cracking Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWB • Examination Category B-G-1 • Examination Category B-P Leakage Detection in Reactor Building Boric Acid Corrosion Prevention Bolting and Torquing Activities
Pressurizer bolting ≤ 2-inches diameter	Pressure boundary	Low-alloy steel heater bundle studs	External-reactor building	Cracking Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWB • Examination Category B-G-1 • Examination Category B-P Leakage Detection in Reactor Building Boric Acid Corrosion Prevention Bolting and Torquing Activities

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components

Component/ Item Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Reactor Vessel					
Reactor vessel shell and closure head	Pressure boundary	SS clad low-alloy steel	Primary water	Cracking at welded joints Reduction of fracture toughness Cracking of 508 Class 2 forgings due to intergranular separation	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-A Reactor Vessel Integrity TLAA-See Section 4.2
	Support and orientation for the core	SS clad low-alloy steel	Primary water	Loss of material (internals support shelf)	ASME Section XI ISI-IWB • Examination Category B-N-1
Reactor vessel nozzles, full penetration welds	Pressure boundary	SS clad low-alloy steel	Primary water	Cracking at welded joints Cracking at nozzle inside radius	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-D
Reactor vessel, pressure retaining partial penetration welded nozzles	Pressure boundary	Alloy 600 CRDM nozzles and incore instrumentation nozzles	Primary water	Cracking at or near welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-E • Examination Category B-P Leakage Detection in Reactor Building CRDM Nozzle and Other Vessel Closure Penetrations Inspection (CRDM penetrations only) Alloy 600 Aging Management (incore nozzles)

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components

Component/ Item Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Reactor vessel interior attachment	Pressure boundary	Alloy 600 core guide lugs	Primary water	Cracking at or near attachment welds to cladding	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-N-2
Reactor vessel bolted closures, pressure retaining seating surfaces	Pressure boundary	SS clad low-alloy steel	Primary water	Loss of material	ASME Section XI ISI-IWB • Examination Category B-G-1 • Examination Category B-N-2 • Examination Category B-P Leakage Detection in Reactor Building
Reactor vessel bolting > 2 inches in diameter	Pressure boundary	Low-alloy steel	External	Cracking Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWB • Examination Category B-G-1 • Examination Category B-P Leakage Detection in Reactor Building Bolting and Torquing Activities Boric Acid Corrosion Prevention
Reactor vessel bolting ≤ 2-inches in diameter (CRDM nozzles)	Pressure boundary	Stainless steel	External	Cracking Loss of mechanical closure integrity	ASME Section XI ISI-, IWB • Examination Category B-G-2 Leakage Detection in Reactor Building Boric Acid Corrosion Prevention Bolting and Torquing Activities

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Reactor Vessel Internals					
Core support shield assembly, core barrel assembly, lower internals assembly, plenum assembly, RVLMS support, thermal shield and associated upper restraint, SSHT	Provide support, orientation, guidance, and protection Provide a passageway for the distribution of the reactor coolant flow to the reactor core Provide gamma and neutron shielding	Austenitic stainless steel Martensitic stainless steel Ni-Cr alloy	Primary water	Loss of material Cracking of base metal, welds, and bolting Reduction of fracture toughness of base metal, welds, and bolting by irradiation embrittlement Reduction of fracture toughness of CASS items Dimensional changes by void swelling Loss of mechanical closure integrity (by stress relaxation and cracking)	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination category B-N-3 Reactor Vessel Internals Aging Management

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
OTSG					
OTSG hemispherical heads	Primary pressure boundary	SS clad carbon steel	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-B • Examination Category B-P Leakage Detection in Reactor Building
OTSG support skirt transition ring	Primary pressure boundary	Low-alloy steel	External	Cracking at welded joints	ASME Section XI ISI-IWB • Examination Category B-H
OTSG primary nozzles, NPS > 1-inch	Primary pressure boundary	SS clad carbon steel	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-D • Examination Category B-P Leakage Detection in Reactor Building
OTSG drain nozzle	Primary pressure boundary	Alloy-600	Primary water	Cracking at or near the welded joint	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building Alloy 600 Aging Management Program
OTSG tubesheets	Primary pressure boundary	Inconel clad low-alloy steel	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-B • Examination Category B-P Leakage Detection in Reactor Building

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
OTSG manways and inspection ports	Primary pressure boundary	SS clad carbon steel	Primary water	Cracking at welded joints Loss of mechanical closure integrity	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-P Leakage Detection in Reactor Building
OTSG tubes, plugs, and sleeves	Primary pressure boundary	Alloy-600 Alloy-690	Primary water	Cracking Loss of material Mechanical distortion	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-Q • Examination Category B-P Leakage Detection in Reactor Building Steam Generator Integrity
	Heat transfer from primary fluid to secondary fluid	Alloy-600 Alloy-690	Primary water	Fouling	Primary Chemistry Monitoring Steam Generator Integrity
OTSG shell, tubesheets, integral attachments	Secondary pressure boundary	Carbon steel	Secondary water	Cracking at welded joints Loss of material	Secondary Chemistry Monitoring ASME Section XI ISI-IWC • Examination Category C-A • Examination Category C-C • Examination Category C-H Boric Acid Corrosion Prevention
OTSG steam outlet nozzles, main feedwater nozzles, EFW nozzles, instrumentation nozzles, temperature sensing nozzles	Secondary pressure boundary	Carbon steel and Alloy- 600	Secondary water	Cracking Loss of material	Secondary Chemistry Monitoring ASME Section XI ISI-IWC • Examination Category C-B • Examination Category C-H

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
OTSG main and emergency feedwater header and piping	Secondary pressure boundary	Carbon steel	Secondary water	Cracking Loss of material	Secondary Chemistry Monitoring ASME Section XI-ISI-IWC • Examination Category C-F-2 • Examination Category C-H •
OTSG secondary manways and inspection ports	Secondary pressure boundary	Carbon steel	Secondary water	Cracking at welded joints Loss of mechanical closure integrity	Secondary Chemistry Monitoring ASME Section XI ISI-IWC • Examination Category C-H
OTSG bolting $\leq$ 2-inches diameter	Primary and secondary pressure boundary	Low-alloy steel manway studs and inspection openings	External-reactor building	Cracking at welded joints Loss of mechanical closure integrity Loss of material	ASME Section XI ISI-IWB and IWC • Examination Category B-G-2 • Examination Category B-P • Examination Category C-H Leakage Detection in Reactor Building Bolting and Torquing Activities
Reactor Coolant Pump					
RCP casing	Pressure boundary	Cast austenitic stainless steel	Primary water	Cracking at welded joints Reduction of fracture toughness	Primary Chemistry Monitoring ASME Section XI ISI-Augmented, IWB • Examination category B-P • Code case N-481(see Section 4.3.6 of the ANO-1 LRA) Leakage Detection in Reactor Building
			External-ambient	None	None

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
RCP cover	Pressure boundary	Cast austenitic stainless steel	Primary water	Cracking Reduction of fracture toughness	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination category B-P • Examination Category B-L-2—when RCP disassembled Leakage Detection in Reactor Building
			External-ambient	None	None
Seal water heat exchanger	Pressure boundary	Alloy 600	Primary water	Cracking Loss of material	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination category B-P Leakage Detection in Reactor Building
RCP bolting > 2 inches in diameter	Pressure boundary	Alloy steel	External	Cracking Loss of mechanical closure integrity Loss of material	ASME Section XI ISI-IWB • Examination Category B-G-1 • Examination Category B-P Leakage Detection in Reactor Building Bolting and Torquing Activities Boric Acid Corrosion Prevention
RCP bolting ≤ 2 inches in diameter	Pressure boundary	Alloy steel	External	Cracking Loss of mechanical closure integrity Loss of material	ASME Section XI ISI-IWB • Examination Category B-G-2 Leakage Detection in Reactor Building Bolting and Torquing Activities Boric Acid Corrosion Prevention

Table 3.2-1 Aging Effects Requiring Aging Management for Reactor Coolant System Components					
Component/ Item Grouping	**Intended Function**	**Material**	**Environment**	**Aging Effect**	**Program/Activity**
Control Rod Drive Mechanism					
Motor tube	Pressure boundary	Austenitic stainless steel Martensitic stainless steel Low-alloy steel clad with alloy 82/182	Primary water	Cracking at welded joints	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-O • Examination Category B-P Leakage Detection in Reactor Building
Closure insert and vent assembly and associated bolting	Pressure boundary	Austenitic stainless steel	Primary water	Loss of mechanical closure integrity	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-G-2 • Examination Category B-P Leakage Detection in Reactor Building Bolting and Torquing Activities
RVLMS adapter flange/closure assembly	Pressure boundary	Austenitic stainless steel	Primary water	Cracking	Primary Chemistry Monitoring ASME Section XI ISI-IWB • Examination Category B-G-2 • Examination Category B-P Leakage Detection in Reactor Building

3.3 ENGINEERED SAFEGUARDS

ANO-1 refers to the engineered safety features as the engineered safeguards. The following systems are included in this section:

- Core Flood
- Low Pressure Injection/Decay Heat Removal
- High Pressure Injection/Makeup and Purification
- Reactor Building Spray
- Reactor Building Cooling and Purge
- Sodium Hydroxide
- Reactor Building Isolation
- Hydrogen Control

Section 2.3.2 provides a description of these systems and identifies the components requiring aging management review for license renewal. The aging effects of specific material and environment combinations are described in Appendix C while the programs utilized to manage the aging effects are described in Appendix B. For the engineered safeguards systems, the specific materials and environments, the resulting aging effects, and the specific programs to manage those effects are listed in Table 3.3-1 through Table 3.3-8.

3.3.1 Materials and Environments

The engineered safeguards systems are exposed to borated water, treated water, raw water, nitrogen, air, sodium hydroxide, lube oil and ambient atmosphere. Most of the piping and piping components in the engineered safeguards systems are stainless steel. Carbon steel piping and piping components are used in the reactor building isolation system and carbon steel tanks are used in the NaOH system and the core flood system. Carbon steel bolting is used externally on some valves and flanges. In addition to stainless and carbon steel, brass/bronze is used for some lube oil piping components, and 90/10 CuNi is used for cooling coils in the reactor building cooling and purge systems.

The components, their intended functions, as well as the materials and environments for each engineered safeguard system are summarized in Table 3.3-1 though Table 3.3-8. The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination for each engineered safeguard system are discussed in the following paragraphs and are summarized in the tables at the end of this section.

3.3.2 Aging Effects Requiring Management

The aging effects requiring management for carbon steel external parts and bolting are loss of material due to leakage of borated water and loss of mechanical closure integrity. This effect is applicable to all subsystems in the engineered safeguards that contain carbon steel.

The stainless steel piping and valve bodies in the LPI/DHR system that are wetted by the sump water are susceptible to cracking and loss of material. Fouling is an aging effect requiring management for the lube oil side of the LPI/DHR pump lube oil coolers and the borated water side of the decay heat coolers. Aging effects for the service water side of the lube oil and decay heat coolers are addressed in Section 3.4.

Fouling is an aging effect requiring management for the pump lube oil coolers in the MUP/HPI system. Cracking is an aging effect for stainless steel in the MUP/HPI.

Cracking and fouling are aging effects for stainless steel in the reactor building spray system.

A specific aging effect applicable to the reactor building cooling and purge system is a loss of material in the reactor building cooler housing and the carbon steel ductwork and dampers. Fouling, loss of material, and loss of mechanical closure integrity are aging effects requiring management for the air cooler coils.

The stainless steel NaOH piping and components could experience cracking and loss of material. The carbon steel sodium hydroxide tank is susceptible to loss of material and loss of mechanical closure integrity.

The aging effects requiring management for the reactor building isolation system piping and valves are loss of mechanical closure integrity, loss of material from the internal surfaces of the carbon steel components, and cracking of stainless steel components of stainless steel components.

Minor fouling on the outside of the air-cooled heat exchangers due to dust and loss of material are identified as aging effects requiring management in the hydrogen control system.

3.3.3 Programs and Activities that Manage Aging Effects

The programs listed below will manage the aging effects identified in Section 3.3.2. Additionally, the Chemistry Control Programs, Oil Analysis Program, and the Maintenance Rule Program will prevent other aging effects from occurring.

- ASME Section XI ISI Program (IWC or IWD) is applicable to all engineered safeguards systems except the reactor building cooling and purge, and hydrogen control systems.
- ASME Inservice Inspection Program Augmented Inspections manage the aging effects of piping and components in the LPI/DHR, and reactor building isolation.
- The Wall Thinning Inspection Program is applicable to the sodium hydroxide tank and the reactor building isolation system.
- Boric Acid Corrosion Prevention Program is applicable to components in the core flood, LPI/DHR, HPI/MUP, reactor building spray, and reactor building isolation systems.
- Reactor Building Leak Rate Testing Program is credited for managing the aging effects of the reactor building penetrations.
- NaOH Tank Level Monitoring is applicable to the sodium hydroxide system.
- Reactor Building Sump Closeout Inspection is credited for the sump inspection for the LPI/DHR system.
- Core Flood Tank Monitoring is applicable to the core flood system.
- Preventive Maintenance Program activities include periodic inspection and cleaning of RB cooler components, interior and exterior inspections of the BWST, and inspections and cleaning of the heat exchanger external surfaces in the hydrogen control system.
- The Maintenance Rule Program is applicable to the core flood, LPI/DHR, HPI/MUP, and reactor building cooling and purge systems.
- The Heat Exchanger Monitoring Program is applicable to coolers in the LPI/DHR, HPI/MUP, and reactor building cooling and purge systems.
- ASME Inservice Inspection Program (IWD) manages the aging effects of piping and components for sodium hydroxide systems.

3.3.4 Operating Experience

A review of operating history using NPRDS and a review of NRC generic communications was performed to validate the set of aging effects requiring management as described in Appendix C. The industry correspondence found to be applicable to the systems in this section includes the following:

- NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"
- NRC Bulletin 89-02, "Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design"
- NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at Power Plants"
- NRC Information Notice 80-05, "Chloride Contamination of Safety-Related Piping and Components"
- NRC Information Notice 80-15, "Axial (Longitudinal) Oriented Cracking in Piping"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in Pressurized Water Reactor Systems"
- NRC Information Notice 91-05, "Intergranular Stress Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles"
- NRC IE Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Piping Containing Boric Acid Solution at PWR's."

In addition, a review was performed at ANO to validate the accuracy and completeness of the list of applicable aging effects based on site experience. From these reviews, no aging effects requiring management were identified beyond those identified in this section.

Table 3.3-1 Core Flood System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Bolting External valve parts	Pressure boundary	Carbon steel	Borated water(2)	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI- IWC (pressure tests) Core Flood Tank Monitoring Boric Acid Corrosion Prevention
			External-ambient	Loss of material(1)	Maintenance Rule
Piping Tubing Valves Orifices	Pressure boundary	Stainless Steel	Borated water	Cracking(1)	Primary Chemistry Monitoring Secondary Chemistry Monitoring
			External-ambient	None	None
Tanks	Pressure boundary	Carbon steel	Borated water(2)	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWC (pressure tests) Boric Acid Corrosion Prevention Maintenance Rule Core Flood Tank Monitoring
			External-ambient	Loss of material (1)	Maintenance Rule
		Stainless steel cladding Inconel	Borated water	Cracking(1)	Primary Chemistry Monitoring Secondary Chemistry Monitoring

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.3-2 Low Pressure Injection/Decay Heat Removal System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Tubing Valves Flow elements Separators Heaters Pumps	Pressure boundary	Stainless steel	Borated water(3)	Cracking(1)	Primary Chemistry Monitoring
			External-ambient	None	None
Bolting External valve parts	Pressure boundary	Carbon steel	Borated water(3)	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWC Inspections Reactor Building Leak Rate Testing Boric Acid Corrosion Prevention Maintenance Rule
Piping Valves Appurtenances (wetted by sump water)	Pressure boundary	Stainless Steel	Raw water Borated water	Loss of material	Reactor Building Sump Closeout Inspection
				Cracking	ASME Section XI ISI -IWC Inspections Augmented Inspections
		Carbon steel	Raw water Borated water	Loss of material Loss of mechanical closure integrity	Reactor Building Sump Closeout Inspection Maintenance Rule

Table 3.3-2 Low Pressure Injection/Decay Heat Removal System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchangers (DH Coolers)	Pressure boundary	Stainless steel	Borated water[2]	Cracking[1]	Primary Chemistry Monitoring
				Loss of material[1]	ASME Section XI ISI-IWC (pressure tests) Heat Exchanger Monitoring
			External-ambient	None	None
	Heat transfer	Stainless steel	Borated water[2]	Fouling	ASME Section XI ISI-IWC (pressure tests) Heat Exchanger Monitoring
				Fouling	Service Water Integrity
Heat exchangers (Lube Oil Coolers)	Pressure boundary	Stainless steel	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	None	None
	Heat transfer	Stainless steel	Lube oil[1]	Fouling[1]	Oil Analysis
BWST	Pressure boundary	Carbon steel	Borated water	Loss of material[1]	Preventive Maintenance
			External-ambient	Loss of material Loss of mechanical closure integrity	Preventive Maintenance

1) Aging effect prevented by referenced program/activity
2) Outside of tubes
3) Component/system leakage

Table 3.3-3 Makeup and Purification/High Pressure Injection System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Flow elements Valves Filters Separators Pumps casings	Pressure boundary	Stainless steel	Borated water	Cracking(1)	Primary Chemistry Monitoring
			External-ambient	None	None
Bolting External valve parts	Pressure boundary	Carbon steel	Borated water(3)	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI –IWC (pressure tests) Reactor Building Leak Rate Testing Boric Acid Corrosion Prevention Maintenance Rule
Piping Valves Filters Tanks	Pressure boundary	Carbon steel Cast iron	Borated water(3)	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI –IWC (pressure tests) Boric Acid Corrosion Prevention Maintenance Rule
			Lube oil	Loss of material(1)	Oil Analysis
Valves	Pressure boundary	Brass Bronze	Lube oil	Loss of material(1)	Oil Analysis
			External-ambient	None	None
Heat exchangers (lube oil coolers)	Pressure boundary	Stainless steel	Lube oil	Cracking(1)	Oil Analysis
			External-ambient	None	None
	Heat transfer	Stainless steel	Lube oil(2)	Fouling(1)	Oil Analysis

1) Aging effect prevented by referenced program/activity
2) Outside of tubes
3) Component/system leakage

Table 3.3-4 Reactor Building Spray System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Bolting External valve parts	Pressure boundary	Carbon steel	Borated water[2]	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWC (pressure tests) Boric Acid Corrosion Prevention
Piping Tubing Valves Separators Pump casings	Pressure boundary	Stainless steel	Borated water	Cracking[1]	Primary Chemistry Monitoring Secondary Chemistry Monitoring
			External-ambient	None	None
Heat exchanger (lube oil coolers)	Heat transfer	Stainless steel	Lube oil[2]	Fouling	Oil Analysis

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.3-5 Reactor Building Cooling and Purge System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Duct Dampers Pipe Valves Fan and cooler housings	Pressure boundary	Carbon steel	Gas-air	Loss of material(1)	Preventive Maintenance Maintenance Rule
			External-ambient	Loss of material(3)	Maintenance Rule
Heat exchangers	Pressure boundary	90/10 CuNi Stainless steel	Gas-air (2)	None	None
		Carbon steel	Gas-air	Loss of material(1) Loss of mechanical closure integrity(1)	Preventive Maintenance Maintenance Rule
			External-ambient	Loss of material (3)	Maintenance Rule
	Heat transfer	90/10 CuNi	Gas-air(2)	Fouling	Preventive Maintenance

1) On surfaces wetted by condensation
2) Outside of tubes
3) Prevented by program

Table 3.3-6 Sodium Hydroxide System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves	Pressure boundary	Stainless steel	Sodium hydroxide	Loss of material	ASME Section XI ISI-IWD (pressure tests) NaOH Tank Level Monitoring
				Cracking	ASME Section XI ISI-IWD (pressure tests)
Bolting External valve parts	Pressure boundary	Carbon Steel	Sodium hydroxide[(2)]	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWD (pressure tests) NaOH Tank Level Monitoring
Tank	Pressure boundary	Carbon steel	Sodium hydroxide	Loss of material	ASME Section XI ISI-IWD (pressure tests) NaOH Tank Level Monitoring Wall Thinning Inspection
			External-ambient	Loss of material[(1)]	Maintenance Rule

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.3-7 Reactor Building Isolation System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves	Pressure boundary	Carbon Steel	Treated water	Loss of Material	ASME Section XI ISI-IWC Inspections Reactor Building Leak Rate Testing Wall Thinning Inspection Secondary Chemistry Monitoring Auxiliary Systems Chemistry Monitoring
			Gas-nitrogen	None	None
			Gas-air	Loss of material	Reactor Building Leak Rate Testing Wall Thinning Inspection
			External-ambient	Loss of material[1]	Maintenance Rule
Bolting	Pressure boundary	Carbon steel	Borated water[2]	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWC Inspections Reactor Building Leak Rate Testing Boric Acid Corrosion Prevention
Piping Valves	Pressure boundary	Stainless steel	Treated water Borated water	Cracking	ASME Section XI ISI IWC Inspections Augmented Inspections Reactor Building Leak Rate Testing Primary Chemistry Monitoring Secondary Chemistry Monitoring Auxiliary Systems Chemistry Monitoring
			Gas-nitrogen	None	None
			External-ambient	None	None

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.3-8 Hydrogen Control System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Valves	Pressure boundary	Stainless steel	Gas-air External-ambient	None	None
Recombiners	Pressure boundary	Stainless steel Incoloy-800	Gas-air External-ambient	None	None
Heat exchangers	Pressure boundary	Stainless steel	Gas-air	None	None
			External-ambient	None	None
	Heat transfer	Stainless steel	Gas-air(2)	None	None
			Gas-air(3)	Fouling	Preventive Maintenance
Sample stations	Pressure boundary	Stainless steel	Gas-air External-ambient	None	None
		Carbon steel	Gas-air	None	None
			External-ambient	Loss of material	Maintenance Rule

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

3.4 AUXILIARY SYSTEMS

The following systems are included in this section:

- Spent Fuel
- Fire Protection
- Emergency Diesel Generator
- Auxiliary Building Sump and Reactor Building Drains
- Alternate AC Diesel Generator
- Halon
- Fuel Oil
- Instrument Air
- Chilled Water
- Service Water
- Penetration Room Ventilation
- Auxiliary Building Heating and Ventilation
- Control Room Ventilation

Section 2.3.3 provides a description of these systems and identifies the components requiring aging management review for license renewal. The aging effects of specific material and environment combinations are described in Appendix C while the programs utilized to manage the aging effects are described in Appendix B. For the auxiliary systems, the specific materials and environments, the resulting aging effects, and the specific programs to manage those effects are listed in Table 3.4-1 through Table 3.4-13.

3.4.1 Materials and Environments

The auxiliary systems are exposed to borated water, raw water, treated water, air, halon, freon, nitrogen, carbon dioxide, fuel oil, lube oil, concrete, soil and groundwater, and ambient atmosphere. Pressure boundary components are constructed of steel, stainless steel, carbon steel, cast iron, brass, bronze, copper, aluminum, glass and admiralty. Components whose intended function is heat transfer are constructed of 90/10 copper-nickel, brass, bronze, admiralty, copper, and stainless steel. In addition, the spent fuel pool racks that provide structural support, and the reactor building sump anti-vortex device, which has the safety function of vortex elimination as well as the reactor building sump floor drains screens, which have a safety function of debris screening, are all constructed of stainless steel. The Boraflex neutron absorber material used in the spent fuel pool is a boron carbide dispersion in an elastomeric silicone.

The components and their intended functions, as well as the materials and environments for each auxiliary system, are summarized in Table 3.4-1 through Table 3.4-13. The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment/material combination are discussed in the following paragraphs and are summarized in the tables at the end of this section.

3.4.2 Aging Effects Requiring Management

The aging effects for carbon steel external parts (bolts, nuts, etc.) in the spent fuel system are a potential loss of material and loss of mechanical closure integrity if leakage of borated water occurs. Cracking is a potential aging effect in the pool liner. Boraflex is addressed as a time-limited aging analysis in Section 4.7.

The aging effect for cast iron or carbon steel components in the fire protection system is a loss of material. The stainless steel, brass and bronze components in the system are subject to a loss of material and cracking. Loss of mechanical closure integrity is an aging effect for the diesel fire pump intake and exhaust subsystem components and lubrication subsystem components. Diesel fire pump exhaust subsystem components are susceptible to a loss of material and cracking, and the heat exchangers are susceptible to a loss of material and fouling. Loss of material and loss of mechanical closure integrity are aging effects for the diesel fire pump cooling water subsystem.

Loss of material is an aging effect for the carbon steel components in the EDG starting air system, cooling water carbon steel components, the unpainted carbon steel internal surfaces, and the outer portion of the intake and exhaust components that could be exposed to rain. Loss of material and fouling are aging effects for the EDG intake air aftercoolers, the lube oil coolers, and the cooling water heat exchangers. The stainless steel components in the EDG system are susceptible to cracking. Since portions of the engine subsystems are exposed to high vibration, loss of mechanical closure integrity is an aging effect for the skid mounted and connected components.

The aging effects for the auxiliary building sump and reactor building drains include a loss of material, cracking of the stainless steel and brass portions of the system that are potentially exposed to chlorides, fluorides, or sulfates, and loss of mechanical closure integrity.

Loss of material and loss of mechanical closure integrity are aging effects for carbon steel in the intake and exhaust system components, the cooling water, and the starting air components in the alternate AC generator system. Loss of material, fouling, and loss of mechanical closure integrity are aging effects for the intake air aftercooler and lube oil cooler, and loss of material, cracking and loss of mechanical closure integrity are aging effects for the exhaust subsystem carbon steel and stainless steel components. Loss of mechanical closure integrity affects the lube oil subsystem components. Fouling and a loss of material are aging effects for the AAC radiator. The aging effect for the AAC building ventilation subsystem components is a loss of material from wetted portions of the exhaust fan housings.

The halon system discharge tube assembly and pilot header flexible tubing and fittings are susceptible to a loss of material or cracking due to frequent disconnecting of equipment.

The fuel oil tanks in the fuel oil system are susceptible to a loss of material from the inside bottom surface. The bulk fuel oil storage tank could also experience a loss of material from the outside surface. Loss of material is an aging effect for the external surface of the underground piping. Loss of mechanical closure integrity is an aging effect for components subjected to engine vibration from the EDGs, AAC diesel, or fire diesel. Fouling is an aging effect for the AAC diesel fuel oil return cooler.

No aging effects were identified for the passive components in the instrument air system due to the exposure to dry gases and internal building environments.

The auxiliary building chiller components are susceptible to a loss of material from carbon steel internal surfaces. The auxiliary building chiller evaporators and condensers are susceptible to a loss of material from the external tube surfaces. Fouling is an aging effect for the heat exchanger tubes. The reactor building penetrations in the chilled water system are susceptible to a loss of material from the internal carbon steel surfaces and from the uninsulated external carbon steel surfaces, as well as a loss of mechanical closure integrity, and cracking of the stainless steel components.

The aging effects for the service water side of the heat exchangers in the service water system as well as the stainless steel, brass and bronze components in this system are loss of material, cracking and fouling. Carbon steel components are susceptible to a loss of material and fouling. The sluice gates are susceptible to a loss of material for the cast iron sub-components and loss of material and cracking of the stainless steel sub-components. The aging effects for the SW pump casings is loss of material from the carbon steel sub-components and loss of material and cracking of stainless steel sub-components.

A loss of material is an aging effect for portions of the penetration room ventilation system exhaust stack exposed to the weather.

Fouling is an aging effect for the external heat transfer surfaces, and for the external surfaces of the tubes and fins of the cooling subsystems in the auxiliary building electrical rooms, switchgear rooms, and decay heat pump rooms. The EDG ventilation subsystem is susceptible to a loss of material from the external surface of the exhaust penthouse assembly and portions of the intake exposed to rain. The decay heat pump room cooling and make up pump room cooling subsystems are also susceptible to a loss of material from the carbon steel components that are adjacent to the cooling coils.

Loss of material is an aging effect for the wet portions of the cooling coils and areas adjacent to or below the cooling coils in the housings for the control room coolers and fouling is an aging effect for the external coil surface of these coolers.

3.4.3 Programs and Activities that Manage Aging Effects

- The Chemistry Control Programs, the Oil Analysis Program, the Instrument Air Quality Program, and Maintenance Rule Program will prevent aging effects from occurring.

Additionally, the programs and activities listed below will manage the aging effects identified in Section 3.4.2.

- Maintenance Rule Program will ensure piping and component integrity is maintained in the fuel oil, chill water, penetration room ventilation and auxiliary building heating and ventilation systems, the alternate AC generator system and the wetted external portions of the EDG exhaust.

- Boric Acid Corrosion Prevention Program is applicable to components in the spent fuel system, and the auxiliary building sump and reactor building drain systems.
- Reactor Building Leak Rate Testing Program is credited for managing the aging effects of the reactor building penetrations.
- ASME Section XI Inservice Inspection Program (IWC or IWD) is credited for managing aging effects in the spent fuel, chilled water, and service water systems.
- The ASME Section XI ISI Augmented Inspection will manage aging effects of components wetted by sump water.
- The Wall Thinning Inspection Program is applicable for the chilled water system.
- The Heat Exchanger Monitoring Program is applicable to the chilled water system for seismic qualification of heat exchangers, and to the EDG heat exchanger testing per GL 89-13.
- Service Water Integrity Program applies to service water testing, cleaning, and inspections per GL 89-13 commitments.
- The Fire Protection Program monitors fire protection system leakage, piping thickness and preventive maintenance and includes sprinkler testing or replacement.
- The Reactor Building Sump Closeout Inspection is credited with inspection of the reactor building sump screens and floor drain screens.
- Preventive Maintenance Program applies to the auxiliary building ventilation system, the fuel oil system, and the control room ventilation system.
- Spent Fuel Pool Monitoring and Spent Fuel Pool Level Monitoring Programs apply to the spent fuel pool liner plate.
- Buried Pipe Inspection Program applies to the service water and fuel oil systems.
- RCP Oil Collection System Inspection applies to the RCP oil collection system
- Alternate AC Diesel Generator Testing and Inspections Program applies to AAC diesel generator system.
- Control Room Ventilation Testing applies to the control room ventilation system.
- EDG Testing and Inspections applies to the EDG system.
- The Control Room Halon Fire System Inspection applies to the halon system.
- Diesel Fuel Monitoring Program applies to the fuel oil system.

3.4.4 Operating Experience

A review of operating history using NPRDS and a review of NRC generic communications was performed to validate the set of aging effects requiring management as described in Appendix C. The industry correspondence that was found applicable to the systems in this section includes the following:

- NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Bulletin 81-03, "Flow Blockage of Cooling Water to Safety System components by Corbicula Sp. (Asiatic Clam) and Mytilus Sp. (Mussel)"
- NRC Bulletin 89-02, "Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design"
- NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at Power Plants"
- NRC Information Notice 79-23, "Emergency Diesel Generator Lube Oil Coolers"
- NRC Information Notice 80-05, "Chloride Contamination of Safety-Related Piping and Components"
- NRC Information Notice 80-15, "Axial (Longitudinal) Oriented Cracking in Piping"
- NRC Information Notice 81-21, "Potential Loss of Direct Access to Ultimate Heat Sink"
- NRC Information Notice 83-51, "Diesel Generator Events"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in Pressurized Water Reactor Systems"
- NRC Information Notice 84-71, "Graphitic Corrosion of Cast Iron in Salt Water"
- NRC Information Notice 85-24, "Failures of Protective Coatings in Pipes and Heat Exchangers"
- NRC Information Notice 85-30, "Microbiologically Induced Corrosion of Containment Service Water System"
- NRC Information Notice 85-56, "Inadequate Environment Control for Components and Systems in Extended Storage or Layup"
- NRC Information Notice 86-73, "Recent Emergency Diesel Generator Problems"
- NRC Information Notice 86-96, "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems"
- NRC Information Notice 87-43, "Gaps in Neutron-Absorbing Material in High-Density Spent Fuel Storage Racks"

- NRC Information Notice 88-37, "Flow Blockage of Cooling Water to Safety System Components"
- NRC Information Notice 88-92, "Potential for Spent Fuel Pool Draindown"
- NRC Information Notice 89-01, "Valve Body Erosion"
- NRC Information Notice 89-07, "Failures of Small-Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Which Render Emergency Diesel Generators Inoperable"
- NRC Information Notice 89-76, "Biofouling Agent: Zebra Mussel"
- NRC Information Notice 90-26, "Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety-Feature Systems"
- NRC Information Notice 90-39, "Recent Problems with Service Water Systems"
- NRC Information Notice 93-70, "Degradation of Boraflex Neutron Absorber Coupons"
- NRC Information Notice 94-59, "Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion"
- NRC Information Notice 94-79, "Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping"
- NRC Information Notice 95-38, "Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks"
- NRC Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment"
- NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"
- NRC IE Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Piping Containing Boric Acid Solution at PWRs."

In addition, a review was performed at ANO to validate the accuracy and completeness of the list of aging effects requiring management based on site experience. From these reviews, no aging effects requiring management were identified beyond those discussed in this section.

Table 3.4-1 Spent Fuel System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Liner plate	Pressure boundary	Stainless steel	Borated water	Cracking	Primary Chemistry Monitoring
			External-Concrete	Cracking	Spent Fuel Pool Level Monitoring
Gates Racks	Structural support	Stainless steel	Borated water	Cracking[1]	Primary Chemistry Monitoring
Piping Valves	Pressure boundary	Stainless steel	Borated water	Cracking[1]	Primary Chemistry Monitoring
Fuel transfer tube blind flanges	Pressure boundary	Stainless steel	Borated water	Cracking[1]	Primary Chemistry Monitoring
Bolting External valve parts	Pressure boundary	Carbon steel	Borated water[2]	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI-IWD (pressure tests) Boric Acid Corrosion Prevention Reactor Building Leak Rate Testing

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.4-2 Fire Protection System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Pumps Piping Valves	Pressure boundary	Cast iron Carbon steel	Raw water	Loss of material	Fire Suppression Water Supply Surveillance Fire Water Piping Thickness Evaluation Reactor Building Leak Rate Testing Service Water Chemical Control
			External-ambient	Loss of material(1)	Maintenance Rule Fire Suppression Water Supply System Surveillance
Piping Valves	Pressure boundary	Stainless steel	Raw water	Loss of material(1) Cracking	Service Water Chemical Control Fire Suppression Water Supply System Surveillance
			External-ambient	None	None
Piping Valves	Pressure boundary	Brass Bronze	Raw water	Loss of material(1) Cracking	Service Water Chemical Control Fire Suppression Water Supply System Surveillance
			External-ambient	None	None
Diesel Fire Pump Subsystems and Components					
Intake air	Pressure boundary	Carbon steel Aluminum	Gas-air	Loss of mechanical closure integrity	Preventive Maintenance Fire Suppression Water Supply System Surveillance
			External-ambient	Loss of material(1)	Maintenance Rule
Exhaust air	Pressure boundary	Carbon steel	Gas-air	Loss of mechanical Closure integrity Cracking Loss of material	Preventive Maintenance Fire Suppression Water Supply System Surveillance
			External-ambient	None	None

Table 3.4-2 Fire Protection System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Lube oil	Pressure boundary	Carbon steel Cast iron	Lube oil	Loss of mechanical closure integrity	Preventive Maintenance Oil Analysis Fire Suppression Water Supply System Surveillance
			External-ambient	None	None
Cooling water	Pressure boundary	Carbon steel Cast iron	Treated water	Loss of mechanical closure integrity Loss of material(1)	Fire Suppression Water Supply System Surveillance
			External-ambient	Loss of material(1)	Maintenance Rule
Heat exchangers	Pressure boundary	Cast iron, Brass	Lube oil	Loss of material	Fire Suppression Water Supply System Surveillance Oil Analysis
			External-ambient	Loss of material	Preventive Maintenance
	Heat transfer	90/10 Cu-Ni Copper	Treated water(2) Lube oil(3)	Fouling	Fire Suppression Water Supply System Surveillance Oil Analysis

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-3 Emergency Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Starting Air Subsystem					
Valves Bolting External valve parts	Pressure boundary	Carbon steel	Gas-air	Loss of material	Emergency Diesel Generator Testing and Inspections
			External-ambient	Loss of material Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections Maintenance Rule
Piping Valves Tanks Strainers	Pressure boundary	Stainless steel	Gas-air	None	None
			External-ambient	None	None
Tubing	Pressure boundary	Copper	Gas-air	None	None
			External-ambient	None	None
Air Intake and Exhaust Subsystems					
Piping Filters Expansion joints Turbochargers	Pressure boundary	Carbon steel	Gas-air	Loss of material Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
			External-ambient	Loss of material(1)	Maintenance Rule
Valves	Pressure boundary	Brass, bronze	Gas-air	Cracking	Emergency Diesel Generator Testing and Inspections
			External-ambient	None	None
Heat exchangers	Pressure boundary	Carbon steel	Gas-air	Loss of material Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
			External-ambient	Loss of material(1)	Maintenance Rule

Table 3.4-3 Emergency Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
	Heat transfer	Copper with aluminum fins	Treated water[2])	Fouling	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Water Chemistry Monitoring
			Gas-air	Fouling	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Water Chemistry Monitoring
Lube Oil Subsystem					
Piping Valves Filters Pumps	Pressure boundary	Carbon steel	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections Maintenance Rule
				Loss of material[1]	Maintenance Rule
Valves	Pressure boundary	Stainless steel	Lube oil	Cracking[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
Filters	Pressure boundary	Aluminum	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
Valves	Pressure boundary	Brass, Bronze, admiralty	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
Sight glasses	Pressure boundary	Glass	Lube oil	None	None
			External-ambient	Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections

Table 3.4-3 Emergency Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Strainer	Pressure boundary	Cast iron	Lube oil	Loss of material(1)	Oil Analysis
			External-ambient	Loss of mechanical closure integrity Loss of material(1)	Emergency Diesel Generator Testing and Inspections Maintenance Rule
Heat exchangers	Pressure boundary	Carbon steel	Treated water	Loss of material(1) Fouling	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Chemistry Monitoring
	Heat transfer	Brass	Lube oil	Fouling	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Chemistry Monitoring
Cooling Water Subsystem					
Pipe Pumps Valves Tanks	Pressure boundary	Carbon steel	Treated water	Loss of material(1)	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Chemistry Monitoring
				Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections
			External-ambient	Loss of material(1)	Maintenance Rule
Valves Thermowells	Pressure boundary	Stainless steel	Treated water	Cracking	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Chemistry Monitoring
			External-ambient	None	None
Level Glass	Pressure boundary	Glass	Treated water	None	None
			External-ambient	None	None

Table 3.4-3 Emergency Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchangers	Pressure boundary	Carbon steel	Treated water	Loss of material(1)	Emergency Diesel Generator Testing and Inspections Auxiliary Systems Chemistry Monitoring
	Heat transfer	Admiralty	Treated water(2)	Fouling	Auxiliary Systems Chemistry Monitoring Emergency Diesel Generator Testing and Inspections
			Lube Oil(3)	Fouling Loss of material(1)	Oil Analysis
	Pressure Boundary	Carbon Steel	Lube Oil(3)	Loss of material(1) Loss of mechanical closure integrity	Emergency Diesel Generator Testing and Inspections Maintenance Rule Oil analysis

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-4 Auxiliary Building Sump and Reactor Building Drain System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves Bolting External valve parts	Pressure boundary	Carbon steel	Treated water, borated water	Loss of material Loss of mechanical closure integrity	Local Leak Rate Testing Primary Chemistry Monitoring Secondary Chemistry Monitoring
			External-ambient	None	None
Piping Valves Tanks Bolting	Pressure Boundary	Carbon Steel	Borated water(1) Oil	Loss of material Loss of mechanical closure integrity	Boric Acid Corrosion Prevention RCP Oil Leakage Collection System Inspection
Piping Valves	Pressure boundary	Stainless steel	Borated water Raw water Treated water	Loss of material Cracking Loss of mechanical closure integrity	ASME Section XI ISI-Augmented Inspections Reactor Building Leak Rate Testing
			External-ambient	None	None
Valves	Pressure boundary	Brass Bronze admiralty	Raw water, treated water, borated water	Loss of material Cracking	ASME Section XI ISI-Augmented Inspections
			External-ambient	None	None
Anti-vortex device	Vortex elimination	Stainless steel	External-ambient	None	None
Screens	Debris screening	Stainless steel	Borated water Treated water Raw water Oil	Loss of material Cracking	Reactor Building Sump Closeout Inspection

1) Component/system leakage

Table 3.4-5 Alternate AC Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Starting Air Subsystem					
Valves Tanks Filters Motor casing	Pressure boundary	Carbon steel	Gas-air	Loss of material	Alternate AC Diesel Generator Testing and Inspection
			External-ambient	Loss of mechanical closure integrity Loss of material(1)	Alternate AC Diesel Generator Testing and Inspection Maintenance Rule
Piping Valves	Pressure boundary	Stainless steel	Gas-air	None	None
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection
Valves	Pressure boundary	Brass, bronze or admiralty	Gas-air	None	None
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection
Valves Filter	Pressure boundary	Aluminum	Gas-air	None	None
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection
Air Intake and Exhaust Subsystems					
Piping Valves Muffler Turbocharger	Pressure boundary	Carbon steel	Gas-air	Loss of material Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection Maintenance Rule
			External-ambient	Loss of material (1)	Maintenance Rule
Valves Expansion joints	Pressure boundary	Stainless steel	Gas-air	Cracking(1)	Alternate AC Diesel Generator Testing and Inspection
			External-ambient	None	None
Filters	Pressure boundary	Aluminum	Gas-air External-ambient	None	None

Table 3.4-5 Alternate AC Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchanger	Pressure boundary	Cast iron	Gas-air	Loss of material Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection Maintenance Rule
			External-ambient	Loss of material [1]	Maintenance Rule
	Heat transfer	Copper admiralty	Treated water[2]	Fouling	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
			Gas-air[3]	Fouling	Alternate AC Diesel Generator Testing and Inspection
Lube Oil Subsystem					
Valves Pumps Heater	Pressure boundary	Carbon steel	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection
				Loss of material[1]	Maintenance Rule
Valves	Pressure boundary	Stainless steel	Lube oil	Cracking[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection
Valves	Pressure boundary	Brass Bronze Admiralty	Lube oil	Loss of material[1]	Oil Analysis
			External-ambient	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection

Table 3.4-5 Alternate AC Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchanger	Pressure boundary	Carbon steel	Treated water	Loss of material Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
	Heat transfer	Copper	Lube oil(2)	Loss of material(1) Fouling	Oil Analysis
			Treated water(3)	Fouling	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
Cooling Water Subsystem					
Piping Valves Pumps Tanks Heaters Orifices Filters	Pressure boundary	Carbon steel	Treated water	Loss of mechanical closure integrity	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
				Loss of material(1)	Auxiliary Systems Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
Valves Thermowells Expansion joints	Pressure boundary	Stainless steel	Treated water	Cracking(1)	Auxiliary Systems Chemistry Monitoring Alternate AC diesel Generator Testing and Inspection
			External-ambient	None	None
Valves	Pressure boundary	Brass Bronze Admiralty	Treated water	Loss of material(1)	Auxiliary Systems Chemistry Monitoring
			External-ambient	None	None

Table 3.4-5 Alternate AC Diesel Generator System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchanger	Pressure boundary	Carbon steel	Gas-air	Loss of material(1)	Maintenance Rule
			External-ambient	Loss of material	Alternate AC Diesel Generator Testing and Inspection
	Heat transfer	Brass Bronze admiralty	Treated water(2) Gas-air (3)	Fouling	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
	Pressure boundary	Brass Bronze admiralty	Treated water(2) Gas-air (3)	Loss of material	Alternate AC Diesel Generator Testing and Inspection Auxiliary Systems Chemistry Monitoring
Alternate AC Building Ventilation					
Fans	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Alternate AC Diesel Generator Testing and Inspection Maintenance Rule
Dampers/louvers	Pressure boundary	Aluminum	Gas-air External-ambient	None	None

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-6 Halon System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Valves	Pressure boundary	Brass	Gas-halon Gas-nitrogen	None	None
			External-ambient	None	None
Pipe	Pressure boundary	Steel	Gas-halon Gas-nitrogen	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Tanks	Pressure boundary	Carbon steel	Gas-halon Gas-nitrogen	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Discharge nozzles	Pressure boundary	Aluminum	Gas-halon Gas-nitrogen	Loss of material	Control Room Halon Fire System Inspection
			External-ambient	None	None
Discharge tube	Pressure boundary	Steel	Gas-halon Gas-nitrogen	Loss of material	Control Room Halon Fire System Inspection
			External-ambient	Loss of material(1) Cracking	Maintenance Rule
Pilot header discharge tube flexible connectors	Pressure boundary	Stainless steel	Gas-halon Gas-nitrogen	Loss of material	Control Room Halon Fire System Inspection
			External-ambient	Loss of material(1) Cracking	Maintenance Rule

1) Aging effect prevented by referenced program/activity

Table 3.4-7 Fuel Oil System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves Filters Pumps Tubing	Pressure boundary	Carbon steel	Fuel oil	Loss of material Loss of mechanical closure integrity	EDG Testing and Inspections Diesel Fuel Monitoring
			External-ambient	Loss of material[1]	Maintenance Rule
			External-buried	Loss of material	Buried Pipe Inspection
Valves Filters Thermowells	Pressure boundary	Stainless steel	Fuel oil	Loss of mechanical closure integrity	EDG Testing and Inspections Diesel Fuel Monitoring
			External-ambient	None	None
Tubing Valves	Pressure boundary	Brass Bronze Copper admiralty	Fuel oil	Loss of mechanical closure integrity	EDG Testing and Inspections Diesel Fuel Monitoring
			External-ambient	None	None
Pumps Strainers	Pressure boundary	Cast iron	Fuel oil	Loss of mechanical closure integrity	EDG Testing and Inspections Diesel Fuel Monitoring
			External-ambient	None	None
Tanks	Pressure boundary	Carbon steel	Fuel oil	Loss of material	EDG Testing and Inspections Diesel Fuel Monitoring
			External-ambient	Loss of material[1]	Maintenance Rule
Heat exchanger	Pressure boundary Heat transfer	Stainless steel	Fuel oil[2]	Fouling	Alternate AC Diesel Generator Testing and Inspections Diesel Fuel Monitoring
			Gas-air[3]	Fouling	Alternate AC Diesel Generator Testing and Inspections

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-8 Instrument Air System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Tubing	Pressure boundary	Stainless steel	Gas-air	Cracking(1)	Instrument Air Quality
			External-ambient	None	None
Tubing	Pressure boundary	Copper	Gas-air	Loss of material(1)	Instrument Air Quality
			External-ambient	None	None
Valves	Pressure boundary	Stainless steel	Gas-air	Cracking(1)	Instrument Air Quality
			External-ambient	None	None
Valves	Pressure boundary	Carbon steel	Gas-air	Loss of material(1)	Instrument Air Quality
			External-ambient	Loss of material(1)	Maintenance Rule
Valves	Pressure boundary	Brass Bronze admiralty	Gas-air	Loss of material(1)	Instrument Air Quality
			External-ambient	None	None
Piping Flanges	Pressure boundary	Carbon steel	Gas-air	Loss of material(1)	Instrument Air Quality
			External-ambient	Loss of material(1)	Maintenance Rule
Tanks	Pressure boundary	Carbon steel	Gas-air	Loss of material(1)	Instrument Air Quality
			External-ambient	Loss of material(1)	Maintenance Rule
Regulators	Pressure boundary	Aluminum	Gas-air	None	None
			External-ambient	None	None

1) Aging effect prevented by referenced program/activity

Table 3.4-9 Chilled Water System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves Thermowells Tanks Pumps	Pressure boundary	Carbon steel	Treated water	Loss of material	Reactor Building Leak Rate Testing ASME Section XI ISI –IWC (pressure tests) Auxiliary Systems Chemistry Monitoring Wall Thinning Inspection
			External-ambient	Loss of mechanical closure integrity	Maintenance Rule
Valves Tubing	Pressure boundary	Stainless steel	Treated water	Cracking(1)	Auxiliary Systems Chemistry Monitoring
			External-ambient	None	None
Valves Coils	Pressure boundary	Brass Bronze Copper	Treated water	Loss of material(1)	Auxiliary Systems Water Chemistry Monitoring
			External-ambient	None	None
Sight glasses	Pressure boundary	Glass	Treated Water	None	None
			External-ambient	None	None
Valves Filters Sight glasses Compressors Mufflers	Pressure boundary	Stainless steel Brass/bronze Carbon steel Glass	Gas-freon External-ambient	None	None
Valves	Pressure boundary	Stainless steel	Lube oil	Cracking(1)	Oil Analysis
			External-ambient	None	None

Table 3.4-9 Chilled Water System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchangers (evaporators)	Pressure boundary	Carbon steel	Treated water	Loss of material	Heat Exchanger Monitoring Auxiliary Systems Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
	Heat transfer	Copper Brass Bronze	Gas-freon(2) Treated water(3)	Fouling	Heat Exchanger Monitoring Auxiliary Systems Chemistry Monitoring
	Pressure boundary	Copper Brass Bronze	Gas-freon(2) Treated water(3)	Loss of material	Auxiliary Systems Chemistry Monitoring
Heat exchangers (condensers)	Pressure boundary	Carbon steel	External-ambient	Loss of material(1)	Maintenance Rule
	Heat transfer	Copper Brass Bronze	Gas-freon(2)	Fouling	
	Pressure boundary	Copper Brass Bronze	Gas-freon(2)	Loss of material	Heat Exchanger Monitoring

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-10 Service Water System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Pumps Strainers Valves	Pressure boundary	Carbon steel	Raw water	Loss of material	Service Water Integrity ASME Section XI ISI -IWC & IWD (pressure tests)
			External-buried	Loss of material	Buried Pipe Inspection
			External-ambient	Loss of material[1]	Maintenance Rule
Piping Pumps Valves Flow elements Thermowells	Pressure boundary	Stainless steel	Raw water	Loss of material Cracking	Service Water Integrity ASME Section XI ISI –IWC & IWD (pressure tests)
			External-ambient	None	None
Valves	Pressure boundary	Brass, bronze	Raw water	Loss of material Cracking	Service Water Integrity ASME Section XI ISI –IWC & IWD (pressure tests)
			External-ambient	None	None
Sluice gates	Pressure boundary	Cast iron	Raw water	Loss of material	Service Water Integrity
			External-ambient	Loss of material[1]	Maintenance Rule
		Stainless steel	Raw water	Loss of material Cracking	Service Water Integrity
			External-ambient	None	None

Table 3.4-10 Service Water System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Heat exchangers	Pressure boundary	Carbon steel	Raw water	Loss of material	Service Water Integrity ASME Section XI ISI –IWC & IWD (pressure tests) Heat Exchanger Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
		Stainless steel	Raw water	Loss of material Cracking	Service Water Integrity ASME Section XI ISI-IWD (pressure tests) Heat Exchanger Monitoring
			External-ambient	None	None
		Copper Stainless steel 90/10 Cu-Ni, admiralty	Raw water(2,3)	Loss of material	Service Water Integrity Heat Exchanger Monitoring
	Heat Transfer	Copper Stainless steel 90/10 Cu-Ni, admiralty	Raw water	Fouling	Service Water Integrity Heat Exchanger Monitoring

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.4-11 Penetration Room Ventilation System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Duct Dampers Valves Expansion joints	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Exhaust stack	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Penetration Room Ventilation System Testing Maintenance Rule
Tubing	Pressure boundary	Copper Brass	Gas-air External-ambient	None	None
Flow elements	Pressure boundary	Stainless steel	Gas-air External-ambient	None	None
Blowers Filters	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule

1) Aging effect prevented by referenced program/activity

Table 3.4-12 Auxiliary Building Heating and Ventilation System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Exterior ductwork, Louvers Fans	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(3)	EDG Testing and Inspections Preventive Maintenance Maintenance Rule
Ductwork Dampers	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Heat exchangers (Switchgear room coolers)	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
		Copper	Gas-air	None	None
	Heat transfer	Copper	Gas-air(2)	Fouling	Preventive Maintenance
Heat exchangers (Decay heat room coolers)	Pressure boundary	Carbon steel	Gas-air	Loss of material(3)	Preventive Maintenance
			External-ambient	Loss of material(1)	Maintenance Rule
		Copper	Gas-air	None	None
	Heat transfer	Copper	Gas-air(2)	Fouling	Service Water Integrity Preventive Maintenance
Heat exchangers (Make up pump room coolers)	Pressure boundary	Carbon steel	Gas-air	Loss of material(3)	Preventive Maintenance
			External-ambient	Loss of material(1)	Maintenance Rule
		90/10 CuNi	Gas-air	None	None

1) Aging effect prevented by referenced program/activity
2) Outside of tubes
3) On surfaces wetted by condensation

Table 3.4-13 Control Room Ventilation System					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Ductwork Dampers Heat exchangers Fans Filters	Pressure boundary	Carbon steel	Gas-air	None	None
			External-ambient	Loss of material(1)	Maintenance Rule
Tubing Valves	Pressure boundary	Copper Brass admiralty	Gas-air & CO_2 External-ambient	None	None
Heat exchangers (Evaporators)	Pressure boundary	Copper	Gas-freon External-ambient	None	None
		Carbon steel	Gas-air & CO_2	Loss of material(4)	Control Room Ventilation Testing Preventive Maintenance
			External-ambient	None	None
	Heat transfer	Copper	Freon(2)	None	None
			Gas-air	Fouling	Control Room Ventilation Testing Preventive Maintenance
Heat Exchanger (Condenser)	Pressure boundary	Carbon steel	External-ambient	Loss of material(1)	Maintenance Rule
			Lube oil	Loss of material(1)	Oil Analysis
	Heat transfer	90/10 CuNi	Freon(2)	None	None
Compressor	Pressure boundary	Carbon steel	Lube Oil	Loss of material(1)	Oil Analysis
			Freon	None	None
			External-ambient	Loss of material(1)	Maintenance Rule

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes
4) On surfaces wetted by condensation

3.5 STEAM AND POWER CONVERSION SYSTEMS

The following systems are included in this section.

- Main steam
- Main feedwater
- Emergency feedwater
- Condensate storage and transfer

Section 2.3.4 provides a description of these systems and identifies the components requiring aging management review for license renewal. The aging effects of specific material and environment combinations are described in Appendix C while the programs utilized to manage the aging effects are described in Appendix B. For the steam and power conversion systems, the specific materials and environments, the resulting aging effects and the specific programs to manage those effects are listed in Table 3.5-1 through Table 3.5-4.

3.5.1 Materials and Environment

The steam and power conversion systems are exposed to treated water, lube oil, nitrogen, air, and ambient atmosphere. The piping, tubing and associated components are constructed of carbon steel, stainless steel, and cast iron. Carbon steel bolting is used externally on valves, flanges, and tank manways. There is brass, bronze, copper and aluminum present in the steam supply and exhaust piping and the lube oil coolers in the EFW system. This is in addition to cast iron, carbon steel, stainless steel, and chrome-moly steel. The potential aging effects for the applicable environment and material combinations are discussed in the following sections.

The components, and their intended functions, as well as the materials and environments for each steam and power conversion system, are summarized in Table 3.5-1 through Table 3.5-4. The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are discussed in the following paragraphs and are summarized in the tables at the end of this section.

3.5.2 Aging Effects Requiring Management

The carbon steel and stainless steel piping and components in the main steam system are subject to cracking, loss of mechanical closure integrity, and loss of material.

The carbon steel piping and valves in the main feedwater system can be affected by a loss of material and cracking. A loss of material and subsequent loss of mechanical closure integrity is a potential aging effect for the bolted carbon steel bolting and closures.

Loss of material is an aging effect requiring management for the EFW pumps, discharge piping and valves, the EFW turbine steam supply and exhaust piping, the cooler housings, and the cooling and seal water piping and valves, which are primarily constructed from carbon steel. Fouling is an aging effect requiring management for the coolers. Loss of mechanical closure integrity is an aging effect for the EFW turbine steam supply piping.

The aging effect requiring management for the carbon steel piping and valves in the condensate storage system is loss of material. Additionally, the carbon steel bolting on the condensate storage tank manways can experience loss of material resulting in a loss of mechanical closure integrity.

3.5.3 Programs and Activities that Manage Aging Effects

The programs listed below will manage the aging effects identified in Section 3.5.2. Additionally, the Secondary Chemistry Monitoring Program, the Oil Analysis Program, and Maintenance Rule Program will prevent other aging effects from occurring.

- The ASME Section XI Inservice Inspection Program (IWC and IWD pressure testing and inspections) is applicable to the steam and power conversion systems.
- Flow Accelerated Corrosion Prevention Program is applicable to components in the main feedwater and main steam systems.
- The Wall Thinning Inspection Program is applicable to carbon steel piping in the main steam and condensate storage and transfer systems. This program will also provide verification of the EFW pressure boundary.
- The ASME Section XI Inservice Inspection Program (Augmented Inspections) will provide special inspection of safety-related stainless steel and carbon steel piping in the Main Steam System and safety-related carbon steel piping in the Main Feedwater System.
- The Heat Exchanger Monitoring Program will provide monitoring of coolers in the EFW tank.
- The Maintenance Rule Program is applicable to the exterior of the safety-related condensate storage tank.
- Leakage Detection in Reactor Building monitors leakage in the reactor building sump per ANO-1 Technical Specifications for components in the reactor building including main feedwater and main steam systems.
- EFW pump testing is applicable to components in the EFW system.

3.5.4 Operating Experience

A review of operating history using NPRDS and a review of NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was found applicable to the systems in this section includes the following:

- NRC Bulletin 79-13, "Cracking in Feedwater System Piping"
- NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Information Notice 80-29, "Broken Studs on Terry Turbine Steam Inlet Flanges"
- NRC Information Notice 81-04, "Cracking in Main Steam Lines"
- NRC Information Notice 84-87, "Piping Thermal Deflection Induced by Stratified Flow"
- NRC Information Notice 86-106, "Feedwater Line Break"
- NRC Information Notice 87-36, "Significant Unexpected Erosion of Feedwater Lines"
- NRC Information Notice 88-17, "Summary of Responses to NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Information Notice 91-18, "High-Energy Piping Failures Caused by Wall Thinning"
- NRC Information Notice 91-19, "Steam Generators Feedwater Distribution Piping Damage"
- NRC Information Notice 91-28, "Cracking in Feedwater System Piping"
- NRC Information Notice 91-38, "Thermal Stratification in Feedwater System Piping"
- NRC Information Notice 92-07, "Rapid Flow-Induced Erosion/Corrosion of Feedwater Piping"
- NRC Generic Letter 79-20, "Information Requested on PWR Feedwater Lines"
- NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning."

In addition, a review was performed at ANO to validate the accuracy and completeness of the list of applicable aging effects based on site experience. From these reviews, no aging effects requiring management were identified beyond those discussed in this section.

Table 3.5-1 Main Steam

Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Tubing Valves Steam traps	Pressure boundary	Carbon steel	Treated water	Loss of material Loss of mechanical closure integrity Cracking	ASME Section XI ISI -IWC Inspections Leakage Detection in Reactor Building Flow Accelerated Corrosion Prevention Wall-Thinning Inspection Secondary Chemistry Monitoring
			Gas-nitrogen	None	None
			External-ambient	Loss of material[1]	Maintenance Rule
Piping Valves Tubing	Pressure boundary	Stainless steel	Treated water	Loss of material Loss of mechanical closure integrity Cracking	ASME Section XI ISI -IWC Inspections Leakage Detection in Reactor Building Secondary Chemistry Monitoring Augmented ISI-special inspection of Q stainless steel piping
			Gas-nitrogen	None	None
			External-ambient	None	None

1) Aging effect prevented by referenced program/activity

Table 3.5-2 Main Feedwater					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Tubing Valves	Pressure boundary	Carbon steel	Treated water	Loss of material Cracking	ASME Section XI ISI -IWC Inspections Leakage Detection in Reactor Building Augmented Inspections Flow Accelerated Corrosion Prevention Secondary Chemistry Monitoring
			Treated water[(2)]	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI –IWC Inspections
			External-ambient	Loss of material[(1)]	Maintenance Rule

1) Aging effect prevented by referenced program/activity
2) Component/system leakage

Table 3.5-3 Emergency Feedwater					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Pumps and discharge piping					
Piping Tubing Valves Pump casings	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI ISI -IWC Inspections Wall Thinning Inspection Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
Orifice plates Valves	Pressure boundary	Stainless steel	Treated water	Cracking(1)	Secondary Chemistry Monitoring
			External-ambient	None	None
Steam supply and exhaust					
Piping Tubing Valves Steam traps Orifice plates Turbine casing	Pressure boundary	Carbon steel Chrome-moly	Treated water	Loss of material Loss of mechanical closure integrity	ASME Section XI –IWC & IWD (pressure tests) Wall Thinning Inspection Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule
Orifice plates Valves Expansion joints	Pressure boundary	Stainless steel	Treated water	Cracking(1)	Secondary Chemistry Monitoring
			External-ambient	None	None
Tubing Valves	Pressure boundary	Brass, bronze, copper	Treated water	Loss of material(1)	Secondary Chemistry Monitoring
			External-ambient	None	None

Table 3.5-3 Emergency Feedwater					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Lubricating oil					
Piping Filter Pump casing	Pressure boundary	Carbon steel	Lube oil	Loss of material(1)	Oil Analysis
			External-ambient	Loss of material(1)	Maintenance Rule
Tubing	Pressure boundary	Stainless steel	Lube oil	Cracking(1)	Oil Analysis
			External-ambient	None	None
Filter	Pressure boundary	Aluminum	Lube oil	Loss of material(1)	Oil Analysis
			External-ambient	None	None
Valve	Pressure boundary	Cast iron	Lube oil	Loss of material(1)	Oil Analysis
			External-ambient	None	None
Heat exchanger (Turbine lube oil)	Pressure boundary (shell, head)	Carbon steel	Lube oil, treated water	Loss of material	Heat Exchanger Monitoring Emergency Feedwater Pump Testing Oil Analysis
			External-ambient	Loss of material(1)	Maintenance Rule
	Pressure boundary (tubes)	Copper	Treated water(2)	Loss of material(1)	Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
			Lube oil(3)	Loss of material(1)	Oil Analysis
Cooling and seal water					
Piping Valves	Pressure boundary	Carbon steel	Treated water	Loss of material	Wall-Thinning Inspection Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
			External-ambient	Loss of material(1)	Maintenance Rule

Table 3.5-3 Emergency Feedwater					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Valves Orifices	Pressure boundary	Stainless steel	Treated water	Cracking(1)	Secondary Chemistry Monitoring
			External-ambient	None	None
Heat exchanger	Pressure boundary	Carbon steel	Treated water	Loss of material	Heat Exchanger Monitoring Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
	Heat transfer	Carbon steel	Treated water(2)	Fouling	Emergency Feedwater Pump Testing Secondary Chemistry Monitoring
			Lube oil(3)	Fouling	Oil Analysis

1) Aging effect prevented by referenced program/activity
2) Inside of tubes
3) Outside of tubes

Table 3.5-4 Condensate Storage and Transfer					
Component Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Piping Tubing Valves Appurtenances	Pressure boundary	Carbon steel	Treated water	Loss of material	ASME Section XI ISI-IWD (pressure tests) Condensate Storage Tank Level Monitoring Secondary Chemistry Monitoring Wall-Thinning Inspection
			External-ambient	Loss of material[1]	Maintenance Rule
Piping Tubing Valves Appurtenances	Pressure boundary	Stainless steel	Treated water	Cracking[1]	Secondary Chemistry Monitoring
			External-ambient	None	None
Tank Tank heater	Pressure boundary	Stainless steel	Treated water	Cracking[1]	Secondary Chemistry Monitoring
			Gas-air	None	None
			External-ambient	None	None
		Carbon steel	External-ambient	Loss of material Loss of mechanical closure integrity	ASME Section XI ISI–IWD (pressure tests) Condensate Storage Tank Level Monitoring Maintenance Rule

1) Aging effect prevented by referenced program/activity

3.6 STRUCTURES AND STRUCTURAL COMPONENTS

Structures and their structural components and commodities that are within the scope of license renewal and subject to aging management reviews, are discussed in Section 2.4 and summarized in Table 3.6-2 through Table 3.6-8. Intended functions and general notes are provided in Table 3.6-1.

Determination of the aging effects applicable to structures and their structural components and commodities begins with identification of the aging effects defined in industry literature. From this set of aging effects, the component and commodity materials and operating environments define the aging effects for each structural component or commodity that is subject to an aging management review. These aging effects are then validated by a review of industry and ANO-1 operating experience to provide reasonable assurance that the full set of aging effects are established for the aging management review.

Structural components and commodities have been grouped into the following construction materials.

- Steel
- Concrete
- Prestressed concrete
- Threaded fasteners
- Fire barriers
- Earthen embankments
- Elastomers and Teflon

3.6.1 Steel

Steel components and commodities are exposed to various service environments depending on location. They are either protected from weather, exposed to weather, exposed to raw water, or exposed to borated water. High temperature, humidity, and radiation play a role in the degradation of the components and commodities located in these environments. Examples of environmental conditions include the following.

- The reactor building liner plate and other steel components are exposed to the internal environment of the reactor building
- Embedments encased in concrete are protected from the external environment and the highly alkaline environment of the concrete protects the steel from corrosion
- Steel inside the auxiliary building may be exposed to elevated temperatures and humidity. Steel outside of the auxiliary building is exposed seasonally to hot and cold temperatures and at times, elevated humidity
- Steel in the intake structure is exposed to raw water
- Steel in the auxiliary building spent fuel pool and the reactor building internals is exposed to borated water

The spent fuel pool steel gates and liner, and the spent fuel steel racks are addressed in Sections 2.3.3 and 3.4. The steel sluice gates are also addressed in these sections.

The review to identify the aging effects for steel, including sub-materials (welds and thermal shields associated with pipe supports) in air or fluid environments considers the following potential aging effects based on available industry literature.

- Loss of material (due to general corrosion, galvanic corrosion, crevice corrosion, pitting corrosion, erosion/erosion-corrosion, MIC and boric acid corrosion)
- Cracking (due to fatigue, stress corrosion, and intergranular attack)
- Change in material properties (due to radiation embrittlement and intermetallic embrittlement)

Other potential aging effects and aging mechanisms do not apply to ANO-1 steel components and commodities due to the absence of susceptible material and environmental conditions. Aging effects for steel associated with the various in-scope structures consider ANO-1 construction materials and environments, and are described in the following subsections. The types of steel components and commodities (i.e., made of carbon steel, stainless steel or galvanized steel) that are subject to an aging management review and the results for ANO-1 are summarized in Table 3.6-1 through Table 3.6-8.

There are no structural steel components or commodities subject to an aging management review made of low-alloy steel. Stainless steel components and commodities are either exposed to interior ambient conditions or borated water. Therefore, aging effects for stainless steel in other environments are not discussed in this section. Referring to Table 3.6-4, the new fuel racks are made of aluminum and have been grouped with steel components and commodities. However, no aging effects were identified for aluminum in an air environment as it is highly resistant to corrosion in atmospheric conditions.

3.6.1.1 Loss of Materials

Loss of material in steel may be caused by corrosion of the steel. This may be seen as material dissolution, corrosion product build-up, and pitting and it may be uniform or localized. General corrosion is the result of a chemical or electrochemical reaction between a material and an aggressive environment. Both oxygen and moisture must be present. Relative humidity, temperature, sulfur dioxide, and chloride concentrations are among important variables. Protective coatings help to prevent the onset of this aging effect. Exposed steel is normally coated for corrosion protection. Therefore, loss of material due to corrosion is not an aging effect as long as the coatings are maintained.

Coatings for the reactor building liner plate, attachments to the liner plate, reactor building penetrations, and reactor building hatches are identified in SAR Section 5.2.1.3.5 and SAR Table 5-2. For the reactor building liner plate, behind miscellaneous welded attachments, loss of material due to corrosion is an aging effect if the cavity formed between the attachment and the liner plate is not sealed to protect against moisture intrusion. For steel encased in concrete, loss of material due to corrosion is not an aging effect because the adjacent concrete provides an alkaline environment that is an effective corrosion inhibitor. An exception to this conclusion may be the reactor building liner plate below the floor if the expansion joint sealant is not maintained.

Due to high humidity and elevated temperatures of the exterior and interior environments of ANO-1 structures (i.e., intake structure, auxiliary building), a loss of material due to general corrosion is an aging effect for carbon steel components and commodities exposed to or protected from weather. Loss of material due to general corrosion is also an aging effect for galvanized steel components and commodities exposed to weather. However, it is not an aging effect for galvanized steel and stainless steel components and commodities protected from weather.

Similarly, since carbon steel is susceptible to corrosion in systems using raw water, a loss of material due to general corrosion and other types of corrosion, is an aging effect applicable to the intake structure carbon steel components and commodities submerged in or wetted by raw water. However, it is not an aging effect for galvanized steel in raw water.

Some stainless steel components within the reactor building are in a borated water environment. Chloride levels in stagnant and low flow areas affect the corrosion of such. However, chloride levels for borated water within the reactor building do not exceed the threshold limit. Therefore, loss of material due to pitting corrosion is not an aging effect requiring management for stainless steel in borated water.

An aging effect requiring management for the control rod drive service structure is loss of material of the lower control rod drive service structure skirt due to corrosion from exposure to boric acid.

An aging effect requiring management for the reactor vessel support skirt is a loss of material of the reactor vessel support skirt, flange, anchor bolts, and shear pins also due to boric acid corrosion.

3.6.1.2 Cracking

Cracking of steel may be caused by fatigue. Cracking due to fatigue has been identified as a time-limited aging analysis for the reactor building liner plate and has been evaluated for the period of extended operation. The results of this evaluation are presented in Section 4.6. For the reactor building liner plate and penetrations, this evaluation has determined that the original fatigue analysis remains valid for the period of extended operation. Furthermore, the design and operation of the steel components and commodities will not exceed the fatigue loading of $2x10^6$ cycles as specified by the AISC.

Dissimilar metal welds are used in certain reactor building penetrations. Where dissimilar metals are used, appropriate welding techniques have been utilized. Bellows are not used in ANO-1 reactor building penetrations. Cracking of dissimilar metal reactor building penetration welds due to fatigue and thermal stresses during plant operations is not likely because the welds are located in a non-aggressive environment.

Therefore, cracking due to fatigue is not an aging effect requiring management for ANO-1 steel components and commodities, except for welds associated with the control rod drive service structure and reactor vessel support skirt.

The reactor building internals contain small amounts of stainless steel in borated water which are utilized in locations that are not necessary for structural integrity. Therefore, cracking of stainless steel components and commodities due to stress corrosion and intergranular attack is not considered to be a significant issue to the structural integrity of the reactor building internals and thus, it is not an aging effect requiring management.

3.6.1.3 Change in Material Properties

A change in material properties driven by radiation embrittlement (for steel inside the primary shield wall), or intermetallic embrittlement (for galvanized steel exposed to temperatures at or above 400°F) is manifested in steel as a reduction or increase in yield strength, reduction in modulus of elasticity, reduction in ultimate tensile ductility, and an increase in ductile-to-brittle transition temperature.

Change in material properties due to radiation exposure is not an aging effect because steel at ANO-1 will not experience radiation exposure above the threshold necessary to cause embrittlement. For the reactor building, the primary shield wall and the concrete pedestal under the reactor vessel provide adequate shielding. The distance between the steel components and commodities and reactor core provides a further reduction in the radiation levels at the steel components and commodities. Other steel components and commodities are not subject to radiation exposure above the threshold necessary to cause embrittlement.

Change in material properties due to intermetallic embrittlement is not an aging effect since galvanized steel components and commodities do not support or protect high temperature piping.

3.6.1.4 Conclusion of Aging Effects for Steel

In conclusion, as a result of the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section were identified.

The aging effect, loss of material, requires management for the following.

- the reactor building liner plate, hatches, and penetrations
- the control rod drive service structure and reactor vessel support skirt
- steel components and commodities

The aging effect, cracking, requires management for the following.

- the control rod drive service structure and reactor vessel support skirt

<u>Management of Aging Effects</u>

The above aging effects must be adequately managed so that the structural intended functions of steel components and commodities are maintained consistent with the current licensing basis for the period of extended operation.

These aging effects will be adequately managed by the following programs that are described in Appendix B.

- Maintenance Rule Program
- Reactor Building Leak Rate Testing Program
- ASME Section XI, Inservice Inspection Program (IWE and IWF)
- Inspection and Preventive Maintenance of the ANO-1 Polar Crane
- Service Water Chemical Control Program
- Battery Quarterly Surveillance
- Boric Acid Corrosion Prevention Program
- Fire Protection Program (Fire Barrier Inspections and Fire Hose Station Inspections)

3.6.2 Concrete

ANO-1 concrete components and commodities are designed in accordance with ACI 318-63 (Reference 3.6-1) and constructed in accordance with ACI 301 (Reference 3.6-2) using material designs conforming to ACI and ASTM standards which provide a good quality, dense, low permeability concrete.

The following discussion provides information on typical environments for concrete components and commodities at ANO-1.

Reactor Building

The reactor building and the reactor building internals concrete components and commodities are exposed to different service environments depending on their location. The top of the concrete floor of the reactor building is exposed to the internal environment of the reactor building. High temperature, humidity, and radiation play a role in the potential degradation of the components located within the reactor building. External surfaces of the reactor building dome and cylinder wall above grade are exposed to external atmospheric conditions. The cylinder wall above grade enclosed by adjacent buildings is exposed to a controlled environment that protects it from external weather. The reactor building concrete foundation slab and the portion of the external cylinder wall below grade are exposed to backfill and groundwater.

Auxiliary Building

Concrete within the auxiliary building may be exposed to elevated temperatures, humidity and radiation. Exterior concrete is exposed to hot and cold temperatures, and at times, elevated humidity. Above grade, exterior concrete is subjected to rainfall, snowfall, and wind. Concrete that is below grade is exposed to chemicals in the groundwater and may also be in direct contact with backfill materials.

Intake Structure

Concrete within the intake structure may be exposed to elevated temperatures and humidity. Exterior concrete is subjected to hot and cold temperatures and, at times, elevated humidity. Above grade, exterior concrete is subjected to rainfall, snowfall, and wind. Concrete that is below grade is exposed to chemicals in raw water (i.e., groundwater, Lake Dardanelle, emergency cooling pond) and may also be in direct contact with backfill materials.

Q-Condensate Storage Tank (Q-CST) Foundation

The foundation of the Q-CST is supported on 42" diameter drilled concrete piers embedded in bedrock. The drilled piers for this foundation are subject to the same, or similar environment as the auxiliary building concrete below grade.

Environments of the other structures, which have concrete components or commodities, are within the parameters of the above structures and, therefore, are not described.

The review to identify the aging effects requiring management for concrete, including sub-materials (non-shrink grout, epoxy grout, embedments, and reinforcement), considers the following potential aging effects based on available industry literature.

- Loss of material (due to abrasion and cavitation or elevated temperature)
- Cracking (due to elevated temperature or restraint against free contraction)
- Change in material properties (due to elevated temperature)

Other potential aging effects and aging mechanisms do not apply to ANO-1 concrete components and commodities due to the absence of susceptible material and environmental conditions. Aging effects for concrete associated with the various in-scope structures consider ANO-1 construction materials and environments and are described in the following subsections. The types of concrete components and commodities (i.e., reinforced concrete, masonry) that are subject to an aging management review and the results for ANO-1 are summarized in Table 3.6-1 through Table 3.6-8

3.6.2.1 Loss of Material

Loss of material is manifested in concrete as scaling, spalling, pitting, and erosion. It may be uniform or localized.

Loss of material due to abrasion and cavitation is limited to concrete that is continuously exposed to running water. The intake structure exterior concrete wall, at the lake level, is an example of concrete exposed to running water (i.e., wave action). Therefore, a loss of material due to abrasion is an aging effect requiring management for the intake structure. However, the highest average water velocity in the intake structure does not exceed the threshold for cavitation damage. Therefore, a loss of material due to cavitation is not an aging effect.

Loss of material due to elevated temperatures may cause concrete surface scaling and cracking. ACI 318-63 provided a maximum temperature limit of 150°F and the ASME Code, Section III, Division 2, Subsection CC, indicates that aging is not significant for concrete temperatures less than 150°F. ACI-349 (Reference 3.6-3) allows local area temperatures to reach 200°F prior to requiring special provisions. Since plant controls maintain temperatures of concrete components and commodities below the established threshold temperature limits, a loss of material due to elevated temperature is not an aging effect.

3.6.2.2 Cracking

Cracking is manifested in concrete as a separation of the concrete into two or more parts. Cracking may occur in concrete as general cracking, map cracking, hairline cracking, pitting, and erosion. The aging mechanism that can lead to cracking of concrete components and commodities is elevated temperature.

As stated above, concrete components and commodities are not exposed to temperatures that exceed the established thresholds for degradation due to elevated temperature as identified in ACI 318-63. Therefore, cracking due to elevated temperature is not an aging effect for concrete components and commodities at ANO-1. However, based on past findings, cracking due to restraint against free contraction is considered an aging effect for masonry block walls. Since there are no exterior block walls associated with in-scope structures at ANO-1, the freezing of water in masonry wall joints does not apply.

3.6.2.3 Change in Material Properties

A change in material properties is manifested in concrete as increased permeability, increased porosity, reduction in pH, reduction in tensile strength, reduction in compressive strength, reduction in modulus of elasticity, and reduction in bond strength. The aging mechanism that could lead to change in material properties of concrete components and commodities is elevated temperature.

As stated above, concrete components and commodities are not exposed to temperatures that exceed the thresholds for degradation identified in ACI 318-63. Change in material properties due to elevated temperature is not an aging effect because concrete is not exposed to temperatures above the threshold limits.

3.6.2.4 Conclusion of Aging Effects for Concrete

In conclusion, as a result of the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section have been identified. This review concludes that the following aging effects for concrete require management for the period of extended operation.

- a loss of material for the intake structure exterior concrete wall at the normal lake level
- cracking for masonry block walls

No aging effects were found to be applicable to the other in-scope concrete components and commodities at ANO-1.

<u>Management of Aging Effects</u>

The programs credited for the management of the identified aging effects for concrete components and commodities are the following.

- Maintenance Rule Program
- Fire Protection Program (Fire Barrier Inspections)

3.6.3 Prestressed Concrete

Reactor building structural components within the scope of license renewal that require aging management reviews and their intended functions are discussed in Section 2.4 and summarized in Table 3.6-2. The ANO-1 reactor building design incorporates a post-tensioning system that provides prestress forces to counteract forces resulting from design loads. Prestressed concrete components for the ANO-1 reactor building considered within the scope of license renewal and subject to aging management review are the following.

- Tendon wires
- Tendon anchorage
- Dome
- Cylinder walls

The prestressed concrete design places the cylinder and dome concrete in compression for normal loading conditions over the current and extended periods of operation. The compression minimizes the number and width of cracks induced by shrinkage, temperature, or load. The prestressed concrete components are designed in accordance with ACI 318-63 and mixed in accordance with ACI 301 (Reference 3.6-2) using ingredients conforming to ACI and ASTM standards, which provide a good quality, dense, low permeability concrete.

The post-tensioning system components are not exposed to external atmospheric conditions with the exception of the tendon end caps. The anchorage system on the bottom of the vertical tendons is exposed to the moist environment of the tendon gallery. The tendon wires are encased in bulk fill grease. The tendon anchors are enclosed in sealed end caps.

The codes and standards used for the reactor building design and fabrication, including the applicable edition, are identified in the ANO-1 SAR Section 5.2. The design of the reactor building post-tensioning buttresses and anchorage zone complies with ACI 318-63 (Reference 3.6-1). The review to identify the aging effects for prestressed concrete components considers the following potential aging effects based on industry literature.

- Loss of material (due to general corrosion)
- Cracking (due to fatigue)
- Change in material properties (due to elevated temperature or radiation embrittlement)
- Loss of prestress (due to material strain)

Other potential aging effects and aging mechanisms do not apply to ANO-1 prestressed concrete components due to the absence of susceptible material and environmental conditions. The aging effects for the reactor building post-tensioning system consider ANO-1 construction materials and environments and are discussed below. The results as they apply to the reactor building post-tensioning system are summarized in Table 3.6-2.

3.6.3.1 Loss of Material

The aging effect that could potentially result in loss of the ability of the post-tensioning system to impose compressive forces on the concrete reactor building structure is loss of material due to general corrosion. Corrosion must be considered for both the carbon steel tendon wires within the grease-filled conduits and for the carbon steel anchorage providing the tendon wire terminations. Stressed components of the post-tensioning system are normally well protected against corrosion. The tendon and the anchorage are enclosed within the ducts and end caps that are filled with bulk fill grease. Although the vertical tendon bottom anchorage is exposed to the moist environment of the tendon gallery, the end caps are coated for corrosion protection, the anchorage is encased in grease, and they are not in direct contact with water. Corrosion at the bottom anchorage of the vertical tendons has not been identified at ANO-1. However, potential grease leakage could occur and would most likely be at the tendon anchorage. Therefore, loss of material due to general corrosion is an aging effect requiring management for the tendon wires and anchorage.

3.6.3.2 Cracking

Cracking due to fatigue could lead to loss of the ability of the post-tensioning system to impose compressive forces on the reactor building structure. The post-tensioning system is not subjected to cyclical loads over the life of the plant. Therefore, cracking due to fatigue is not an aging effect.

However, minor concrete cracking has been observed on a few exposed concrete surfaces of the ANO-1 reactor building. Thus, cracking is an aging effect requiring management for the dome and cylinder wall. Engineering review of these locations has determined that the cracking will not challenge the intended functions of the reactor building prestressed concrete components under design basis loads.

3.6.3.3 Change in Material Properties

A change in material properties is manifested in concrete as increased permeability, increased porosity, reduction in pH, reduction in tensile strength, reduction in compressive strength, reduction in modulus of elasticity, and reduction in bond strength. Aging mechanisms that can lead to change in material properties include elevated temperature or radiation embrittlement.

Prestressed concrete components are not exposed to temperatures that exceed the thresholds for degradation identified in ACI 318-63. Therefore, change in material properties due to elevated temperature is not an aging effect. Change in material properties due to radiation exposure is also not an aging effect because the reactor building prestressed concrete components will not experience sufficient radiation to cause embrittlement.

However, based on ANO-1 operating experience, some leaching (i.e., change in material properties) has been observed on a few exposed concrete surfaces of the reactor building. Thus, change in material properties is an aging effect requiring management for the dome and cylinder wall. Engineering review of these locations has determined that the leaching will not challenge the intended functions of the reactor building prestressed concrete components under design basis loads.

3.6.3.4 Loss of Prestress

Loss of prestress due to material strain occurring under constant stress has been identified as a time-limited aging analysis and is evaluated in Section 4.5.

3.6.3.5 Conclusion of Aging Effects for Prestressed Concrete

As a result of the review of industry information and NRC generic communications, no additional aging effects requiring management beyond those discussed in this section have been identified. Loss of material due to general corrosion was determined to be an aging effect requiring management for the period of extended operation for the tendon wires and anchorage. Material loss at the tendon anchorage can ultimately lead to tendon failure if the corrosion progresses to the point of cracking of the tendon anchorage. Cracking and change in material properties are also aging effects requiring management.

<u>Management of Aging Effects</u>

The programs credited for the management of the identified and observed aging effects for prestressed concrete components are the following.

- ASME Section XI Inservice Inspection Program–IWL Inspections
- Maintenance Rule Program

3.6.4 Threaded Fasteners

As indicated in Table 3.6-1 through Table 3.6-8, in-scope threaded fasteners are made of the same materials as other steel components and commodities. The environmental conditions for threaded fasteners are the same as those for steel. Refer to the discussion in Section 3.6.1.

High strength fasteners used in seismic category 1 areas are ASTM-A325 (Reference 3.6-4) or ASTM-A490 (Reference 3.6-5). Other fasteners in seismic category 1 areas are ASTM-A307 (Reference 3.6-6). ASTM-A325 and ASTM-A307 fasteners are made of carbon steel. ASTM-A490 fasteners are made of alloy steel. However, threaded fastener materials, such as ASTM-A307, may be zinc-coated. Therefore, aging effects for galvanized steel threaded fasteners are also evaluated, in addition to those for stainless steel threaded fasteners.

Except for embedded bolts, fasteners associated with the spent fuel pool gates and liner, the spent fuel racks, and sluice gates are addressed in Sections 2.3.3 and 3.4. Embedded bolts are addressed in Section 3.6.2.

Based on available industry literature, the potential aging effects for threaded fasteners, including sub-materials (structural bolts, expansion anchors, and undercut anchors), are as follows.

- Loss of material (due to boric acid wastage, general corrosion and other forms of corrosion)
- Cracking of bolting material (due to stress corrosion and intergranular attack)
- Change in material properties (due to radiation embrittlement and intermetallic embrittlement)

Other potential aging effects and aging mechanisms do not apply to ANO-1 threaded fasteners due to the absence of susceptible material and environmental conditions. Aging effects for threaded fasteners associated with the various in-scope structures consider ANO-1 construction materials and environments and are described in the following subsections. The types of threaded fasteners subject to an aging management review and the results for ANO-1 are summarized in Table 3.6-1 through Table 3.6-8.

3.6.4.1 Loss of material

Loss of material due to boric acid wastage is generally found in closures of reactor coolant systems. Structural steel connections may be exposed to boric acid if the closures leak. Loss of material due to boric acid wastage is an aging effect for non-boron treated (i.e., those other than A325 low carbon martensitic) threaded fasteners in the vicinity of the spent fuel pool since it contains borated water.

Loss of material due to general corrosion is typically attributed to leaking joints. Loss of material due to general corrosion is an aging effect for carbon steel and low-alloy steel threaded fasteners protected from or exposed to weather, and in raw water. It is also an aging effect for galvanized steel threaded fasteners exposed to weather.

Stainless steel is susceptible to a loss of material due to general corrosion if chlorides are present. It is considered to be an aging effect for stainless steel threaded fasteners since ANO-1 raw water contains chlorides (i.e., applicable to the intake structure). Loss of material due to other forms of corrosion (i.e., crevice corrosion, pitting corrosion, MIC) is also an aging effect requiring management for stainless steel threaded fasteners in raw water. However, loss of material is not an aging effect requiring management for stainless steel threaded fasteners in borated water.

3.6.4.2 Cracking

Cracking of bolting material may be attributed to stress corrosion and intergranular attack. Reported failures have been limited to high strength or ultra-high strength bolting. However, since the specified yield strengths for ANO-1 high strength bolts (i.e., ASTM-A325 and ASTM-A490) do not exceed the threshold, cracking is not an aging effect.

Stress corrosion cracking is not an aging effect for stainless steel threaded fasteners protected from weather because the maximum yield strength for austenitic stainless steel is less than that for reported degradation. However, the chloride content of raw water affects the cracking of stainless steel. Therefore, stress corrosion cracking is an aging effect requiring management for stainless steel threaded fasteners in a raw water environment (i.e., those associated with the intake structure). Since materials susceptible to stress corrosion are also susceptible to intergranular attack, cracking due to intergranular attack is an aging effect requiring management for stainless steel threaded fasteners in raw water. However, cracking is not an aging effect for stainless steel threaded fasteners in borated water.

3.6.4.3 Change in Material Properties

For a general description of a change in material properties, refer to Section 3.6.1.

As discussed for steel components and commodities in Section 3.6.1.3, a change in material properties due to radiation embrittlement is not an aging effect for threaded fasteners at ANO-1. A change in material properties due to intermetallic embrittlement is also not an aging effect since galvanized steel fasteners are not used on high temperature piping systems.

3.6.4.4 Conclusion of Aging Effects For Threaded Fasteners

In order to validate the aging effects, industry literature and ANO-1 operating experience were also reviewed. These documents did not identify other age-related degradation issues.

Similarly, the results of ANO-1 structural-related walkdowns, performed in response to NRC Bulletins 79-02 and 79-14, indicated less than a one percent deficiency rate at support anchorage points. During a more recent walkdown, no deteriorated threaded fasteners were found. Additionally, since the ANO-1 design considers adequate preload of bolted connections and adequate installation, self-loosening by vibration is not an aging effect.

In conclusion, as a result of the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section have been identified.

Management of Aging Effects

Considering that the materials, environments, and aging effects requiring management for threaded fasteners are similar to or the same as those for steel components and commodities, the same programs are credited for the management of their aging effects. Refer to Section 3.6.1.

3.6.5 Fire Barriers

Fire barrier commodities include fire wraps and fire stops associated with 10CFR50.48-required fire barrier walls and floors and are located within the reactor building, auxiliary building, diesel fuel vault, and some areas of the turbine building. Fire wraps may be spray applied, trowelled on, or wrapped onto members. Fire stops are materials used to close gaps in penetrations.

Fire barriers comprise a variety of materials and are exposed to internal ambient environments. Based on available information, the following are potential aging effects for fire barrier commodities.

- Loss of material (due to flaking and abrasion)
- Cracking, delamination, and separation (due to vibration, movement and shrinkage)
- Change in material properties (due to radiation)

Other potential aging effects and aging mechanisms do not apply to ANO-1 fire barriers due to the absence of susceptible material and environmental conditions. Aging effects for fire barrier commodities associated with the various in-scope structures consider ANO-1 construction materials and environments and are described in the following subsections. The types of fire barrier commodities subject to an aging management review and the results for ANO-1 are summarized in Table 3.6-8.

3.6.5.1 Loss of Material

Loss of material decreases the material's fire rating over time. Flaking may occur as fire wrap fibers become free due to force, gravity, airflow, and vibration. Since spray-applied fireproofing may become loose or airborne, loss of material due to flaking is an aging effect for fire wraps (excluding rigid types). Abrasion may occur if the fire barrier experiences continuous movement or interfaces with a moving item. Considering that there is vibrating equipment within the various structures, loss of material may also occur due to abrasion and is an aging effect for both fire wraps and fire stops.

3.6.5.2 Cracking, Delamination, and Separation

Cracking and delamination may occur in fire barrier commodities due to vibrations. As a result of vibrating equipment within the various structures, cracking and delamination are aging effects for ANO-1 fire wraps and fire stops. In addition, vibration may destroy the adhesion between a fire stop and an adjacent surface resulting in separation. Separation of fire stops, as well as cracking and delamination, may also be due to movement and shrinkage. Although movement is not expected to increase during the period of extended operation, ANO-1 fire stops may be exposed to differential movement. Therefore, cracking, delamination, and separation due to movement are aging effects requiring management for fire stops. Cracking, delamination, and separation due to shrinkage are also aging effects requiring management for sealant used at floor and wall piping penetrations, in contact with piping.

3.6.5.3 Change in Material Properties

Change in material properties due to gamma radiation may occur above a radiation exposure of 10^6 rads. Radiation exposure in the reactor building and in some rooms of the auxiliary building may exceed the established threshold limit. However, the threshold is not exceeded in other structures that have fire barriers. Therefore, a change in material properties due to radiation is an aging effect requiring management for ANO-1 fire barrier commodities within the reactor building and some rooms of the auxiliary building.

3.6.5.4 Conclusion of Aging Effects For Fire Barriers

In conclusion, as a result of the review of industry information, NRC generic communications, and ANO-1 operating experience, no additional aging effects beyond those discussed in this section have been observed. These reviews support that loss of material, cracking, delamination, separation, and change in material properties are aging effects requiring management for fire barrier commodities.

Management of Aging Effects

These aging effects must be managed during the period of extended operation so that the structural intended function of fire barriers is maintained. The Fire Protection Program-Fire Barrier Inspections is credited for managing these aging effects and is described in Appendix B.

3.6.6 Earthen Embankments

The emergency cooling pond and intake and discharge canals were evaluated for the aging effects of loss of material, loss of form, and loss of material properties. The design of the emergency cooling pond and intake and discharge canals minimizes the potential for occurrence of detrimental aging effects. Loss of form is the aging effect requiring management for the period of extended operation for the emergency cooling pond as reflected in Table 3.6-6. Frost action, wind erosion, and change in material properties due to desiccation are precluded based on the original design and the absence of an aggressive environment.

Loss of form due to sedimentation of the emergency cooling pond and intake and discharge canals is an aging effect. However, loss of form due to sedimentation effects for the intake and discharge canals is limited because of the engineered features for maintaining maximum flow. This design feature is controlled through power operations to ensure that sediment build-up does not affect safety systems. As the likelihood of buildup is minimized, an aging management program is not required for the intake and discharge canals. The aging management program being credited with managing the potential loss of form for the emergency cooling pond is the Annual Emergency Cooling Pond Sounding.

3.6.7 Elastomers and Teflon

Elastomers associated with ANO-1 structures and their components and commodities are made of rubber or neoprene, or have similar properties. Elastomers are exposed to various air conditions, fluids, and radiation. The use of Teflon (or polytetrafluoroethylene materials) is typically used at sliding surfaces; however, its use is limited at ANO-1. Based on application, Teflon is exposed to the interior environments of structures.

The following are potential aging effects for elastomers.

- Cracking (due to ultraviolet radiation [rubber only], thermal exposure and ionizing radiation)
- Change in material properties (due to ultraviolet radiation [rubber only], thermal exposure and ionizing radiation)

The potential aging effect for Teflon is a change in material properties due to radiation exposure.

Other potential aging effects and aging mechanisms do not apply to ANO-1 elastomeric and Teflon components and commodities due to the absence of susceptible material and environmental conditions. Aging effects for elastomers and Teflon consider ANO-1 construction materials and environments and are described in the following subsections. The types of elastomers (i.e., waterstops) and Teflon, which are subject to an aging management review, and the results for ANO-1 are summarized in Table 3.6-8.

3.6.7.1 Cracking

Ultraviolet radiation (i.e., sunlight) can cause cracking in rubber elastomers. Cracking, due to ultraviolet radiation is not an aging effect for rubber elastomers (i.e., rubber waterstops) since they are concealed in the exterior walls of ANO-1 structures and not exposed to sunlight.

Cracking due to thermal exposure may occur if the ambient temperature is 95°F or above. Cracking due to thermal exposure is not an aging effect for elastomers associated with the exterior environment (i.e., waterstops at construction joints within exterior walls, most of which are located below grade) since the threshold temperature will not be exceeded.

Cracking due to ionizing radiation may alter the molecular structure of elastomers if exposed to 10^6 rads or greater. However, cracking due to ionizing radiation is not an aging effect for elastomers in exterior walls (waterstops) since the radiation threshold will not be exceeded.

3.6.7.2 Change in Material Properties

As for cracking, change in material properties due to ultraviolet radiation, thermal exposure, and ionizing radiation is not an aging effect for elastomers in exterior walls (waterstops).

Change in material properties for Teflon results in a decrease in tensile strength, ultimate elongation, and Young's modulus. The flexure modulus increases. Exposure to a radiation dose of 10^4 rads may cause scission (i.e., breaking of chemical bonds). Since radiation exposures within ANO-1 structures containing Teflon materials (i.e., the reactor building and auxiliary building) may exceed the radiation threshold dose, this is an aging effect requiring management.

3.6.7.3 Conclusion on Aging Effects for Elastomers and Teflon

No additional aging effects beyond those discussed above were identified for elastomers or Teflon in the Entergy Operations' review of industry correspondence and ANO-1 operating experience. Therefore, although no aging effects requiring management were identified for elastomeric components, change in material properties is an aging effect requiring management for Teflon.

Management of Aging Effects

The management of aging effects for Teflon will be performed under the following programs.

- Maintenance Rule Program
- ASME Section XI Inservice Inspection Program-IWF

3.6.8 References for Section 3.6

3.6-1 ACI 318-63, "*Building Code Requirements for Reinforced Concrete*," American Concrete Institute.

3.6-2 ACI 301, "*Specifications for Structural Concrete for Buildings*," American Concrete Institute.

3.6-3 ACI 349, "*Code Requirements for Nuclear Safety-related Concrete Structures*," American Concrete Institute.

3.6-4 ASTM A325, "*Standard Specification for Structural Bolts, Steel, Heat Treated, 120/105 ksi Minimum Tensile Strength*," American Society for Testing and Materials.

3.6-5 ASTM A490, "*Standard Specification for Heat-Treated Steel Structural Bolts, 150 ksi Minimum Tensile Strength*," American Society for Testing and Materials.

3.6-6 ASTM A307, "Standard Specification for Carbon Steel Bolts and Studs, 60,000 PSI Tensile Strength," American Society for Testing and Materials.

Table 3.6-1 Intended Functions and General Notes for Tables 3.6-2 through 3.6-8

LIST OF INTENDED FUNCTIONS:

1) Provide essentially leak tight barriers to prevent uncontrolled release of radioactivity.
2) Provide structural support or functional support to safety-related equipment.
3) Provide shelter or protection to safety-related equipment (including radiation shielding).
4) Provide rated fire barriers to confine or retard a fire from spreading to, or from, adjacent areas.
5) Serve as missile (internal or external) barriers.
6) Provide structural or functional support to nonsafety-related equipment, failure of which could directly prevent satisfactory accomplishment of required safety-related functions.
7) Provide protective barriers for internal flood event.
8) Provide protective barriers for external flood event.
9) Provide for storage of spent fuel assemblies.
10) Provide a heat sink during design basis accidents or station blackout.

GENERAL NOTES:

* Denotes commodity

A) The spent fuel pool steel gates and liner, the spent fuel steel racks, and their associated fasteners (excluding embedded bolts) are addressed in Sections 2.3.3 and 3.4. Some of the threaded fasteners within the auxiliary building may be galvanized steel; however, no aging effects were identified for such.
B) Embedments include plates and bolts below the concrete surface. Reinforcement includes embedded bars, wires, and strands.
C) The steel sluice gates and their associated fasteners (excluding embedded bolts) are addressed in Sections 2.3.3 and 3.4.
D) For steel or threaded fasteners associated with the intake structure that are normally submerged in water, Maintenance Rule walkdowns will be coordinated with the inspection and cleaning of the service water and circulating water bays.
E) For steel or threaded fasteners normally submerged in water, the Service Water Chemical Control Program supplements the management of aging effects.
F) Aging effect applies to wall at the normal lake level (approx. El. 338').
G) Includes mounting brackets for snubbers, but excludes snubbers since they are active commodities and not subject to an aging management review.

Table 3.6-1 Intended Functions and General Notes for Tables 3.6-2 through 3.6-8
H) Fire damper curtains and trap doors are active commodities and not subject to an aging management review. I) Although the turbine building is not a structure within the scope of license renewal, there are 10CFR50.48-required fire components and commodities within it that are in-scope and subject to aging management review. Environmental conditions for the turbine building are within the parameters of the auxiliary building. J) Associated with 10CFR50.48-required fire walls or floors. Penetration sealant used as a fire stop is fire rated. K) 10CFR50.48-required floors and walls provide a fire barrier function. L) For fireproof hatches, those associated with 10CFR50.48-required fire barrier floors are within the scope of license renewal and subject to aging management review. M) Bulk commodities support or protect various in-scope system components or equipment, and are common to two or more structures. N) For seismic category 1 areas, low-alloy threaded fasteners (ASTM-A490) may have been used in addition to carbon steel threaded fasteners in association with carbon steel components and commodities. Since the aging effects for the operating environments are the same for carbon steel and low-alloy steel fasteners, only carbon steel is noted as the fastener material. O) Banding by itself is not considered a fire barrier. However, in conjunction with 10CFR50.48-required fire wraps, it also fulfills intended function number 4. P) Includes reactor building internals. Q) Except piping and equipment integral attachments. R) Applies to the decay heat vaults. S) Applies to the intake structure. T) Refer to associated steel commodity grouping for applicable structure, environment, and program or activity. U) Applies to the reactor building and auxiliary building.

Table 3.6-2 Reactor Building					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL (Sub-materials: Welds)					
Liner plate Anchorage/embedment/ attachment Threaded fasteners[N] Personnel hatch Emergency personnel hatch Equipment hatch Mechanical penetrations Electrical penetrations Fuel transfer tube	1,2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWE Reactor Building Leak Rate Testing
CONCRETE (Sub-materials: Non-Shrink Grout, Epoxy Grout, Embedments[B], and Reinforcement[B])					
Dome Cylinder wall	2,3,4,5,6, 10	Prestressed concrete	Exposed to weather	Cracking Change in material properties	Maintenance Rule ASME Section XI ISI-IWL
Floor	2,3,4,5,6, 10	Reinforced concrete	Protected from weather	None	None
Foundation	2,3,4,5,6, 10	Reinforced concrete	Exposed to weather	None	None
POST TENSIONING SYSTEM					
Tendon wires Tendon anchorage	2	Carbon steel	Protected from weather	Loss of material	ASME Section XI ISI-IWL

Table 3.6-3 Reactor Building Internals					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL (Sub-materials: Welds)					
Anchorage/embedment/ attachment Threaded fasteners[N]	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWF[Q]
Structural shapes	5,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWF[Q] Boric Acid Corrosion Prevention
		Stainless steel	Protected from weather Borated water	None	None
OTSG support steel Pressurizer support steel	5,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWF[Q] Boric Acid Corrosion Prevention
Main fuel handling bridge Jib cranes ANO-1 polar crane	6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule Inspection and Preventive Maintenance of ANO-1 Polar Crane
Control rod drive service structure Reactor vessel support skirt	2,3	Carbon steel	Protected from weather	Loss of material Cracking	Boric Acid Corrosion Prevention ASME Section XI ISI-IWF[Q]
CONCRETE (Sub-materials: Non-shrink Grout, Epoxy Grout, Embedments[B] and Reinforcement[B])					
Primary and secondary shield walls	2 to 6	Reinforced concrete	Protected from weather	None	None
Reinforced concrete	2,3,4,5,6, 10		Protected from weather	None	None

Table 3.6-3 Reactor Building Internals					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Columns Other walls Hatches	2,6	Reinforced concrete	Protected from weather	None	None
Reactor missile shield	2,5	Reinforced concrete	Protected from weather	None	None
Fuel transfer canal	3	Reinforced concrete	Protected from weather	None	None

Table 3.6-4 Auxiliary Building					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL[A] (Sub-materials: Welds)					
Control room extension substructure	5	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Tornado missile shield wall, El. 354'	5	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Boron holdup tank vault beams (top of steel El. 353'-3 7/8")	2	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Spent fuel pool superstructure	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Fire doors (10CFR50.48-required)[I, J]	4	Carbon steel	Protected from weather	Loss of material	Fire Protection • Fire Barrier Inspections
Watertight/flood doors	7	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
HELB doors	3	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Missile/impingement doors	3,5	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
*New fuel racks	2	Aluminum	Protected from weather	None	None
*Main steam line support structure (El. 341' to El. 354')	2	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
*Fuel storage bridge assembly (H3) framing	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
*Battery racks (i.e., associated with Battery banks D06 and D07)	2	Carbon steel	Protected from weather	Loss of material	Battery Quarterly Surveillance
*Exterior louvers (i.e., EDG stack venting)	2	Carbon steel	Exposed to weather	Loss of material	Maintenance Rule
*Exhaust stack supports (i.e., EDGs and EFW turbine)	2	Carbon steel	Protected from weather Exposed to weather	Loss of material	Maintenance Rule

Table 3.6-4 Auxiliary Building					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
*Control room panel supports	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
*Control room halon system supports and bottle racks	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
THREADED FASTENERS[A,N] (Sub-materials: Structural Bolts, Expansion Anchors, and Undercut Anchors)					
Threaded fasteners for: Control room Tornado missile shield wall Boron holdup tank vault beams Spent fuel pool superstructure Watertight/flood doors HELB doors Missile/impingement doors	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Threaded fasteners for: Fire doors (10CFR50.48-required)	2,6	Carbon steel	Protected from weather	Loss of material	Fire Protection • Fire Barrier Inspections
* Threaded fasteners for: New fuel racks	2,6	Aluminum	Protected from weather	None	None
* Threaded fasteners for: Main steam line support structure Fuel storage bridge assembly (H3) framing Control room panel supports Control room halon system supports and bottle racks	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule

Table 3.6-4 Auxiliary Building					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Threaded fasteners for: Battery racks	2,6	Carbon steel	Protected from weather	Loss of material	Battery Quarterly Surveillance
* Threaded fasteners for: Exterior louvers (i.e., EDG stack venting)	2,6	Carbon steel	Exposed to weather	Loss of material	Maintenance Rule
* Threaded fasteners for: Exhaust stack supports (i.e., EDGs and EFW turbine)	2,6	Carbon steel	Protected from weather Exposed to weather	Loss of material	Maintenance Rule
CONCRETE (Sub-materials: Non-shrink Grout, Epoxy Grout, Embedments[B], and Reinforcement[B])					
PASS building sub-structure[K]	4,6,7	Reinforced concrete	Protected from weather	None	None
Building foundation mat (El. 317', El. 335')	2,6,8	Reinforced concrete	Exposed to weather	None	None
Floor slabs[I, K] (El. 335', El. 354', El. 372', El. 386', El. 404')	2,4,6	Reinforced concrete	Protected from weather	None	None
Exterior walls, below grade[K] (El. 317' to approx. El. 354')	2,4,6,8	Reinforced concrete	Exposed to weather	None	None
Exterior walls, above grade[K] (approx. El. 354' and above)	2,4,5,6	Reinforced concrete	Exposed to weather	None	None
Columns and beams (all floors)	2,6	Reinforced concrete	Protected from weather	None	None
Roof slabs	3	Reinforced concrete	Exposed to weather	None	None
Interior walls[I, K] (load bearing)	1[R],2,4,5,6,7	Reinforced concrete	Protected from weather	None	None
	2,4,5,6,7	Masonry blockwalls	Protected from weather	Cracking	Maintenance Rule Fire Protection: • Fire Barrier Inspections

Table 3.6-4 Auxiliary Building					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Boron holdup tank vault (slabs at El. 327' and El. 355'-4" and vault room walls)	2	Reinforced concrete	Protected from weather	None	None
Main steam line tunnel (El. 341' to El. 354')	3	Reinforced concrete	Protected from weather	None	None
Spent fuel pool bottom slab and walls	9	Reinforced concrete	Protected from weather	None	None
Small pipe chase at approx. El. 341'	2	Reinforced Concrete	Protected from weather	None	None
Sump at El. 317'	2	Reinforced concrete	Protected from weather	None	None

Table 3.6-5 Intake Structure					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL[C] (Sub-materials: Welds)					
Beams in service water bays (top of steel El. 351'-7 ½")	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Louvered doors	2	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
*Supports for roof hatch Nos. 75, 76, and 77	2,5,6	Carbon steel	Protected from weather Exposed to weather	Loss of material	Maintenance Rule
*Submerged pump shaft supports	2,6	Carbon steel	Raw water	Loss of material	Maintenance Rule [D] Service Water Chemical Control[E]
*Supports for fire pump diesel storage tank	2	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
THREADED FASTENERS[C,N] (Sub-materials: Structural Bolts, Expansion Anchors, and Undercut Anchors)					
Threaded fasteners for steel beams in service water bays	2, 6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
Threaded fasteners for louvered doors	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
* Threaded fasteners for above indicated roof hatch supports	2, 6	Carbon steel	Protected from weather Exposed to weather	Loss of material	Maintenance Rule
* Threaded fasteners for submerged pump shaft supports	2, 6	Carbon steel	Raw water	Loss of material	Maintenance Rule [D] Service Water Chemical Monitoring[E]
* Threaded fasteners for fire pump diesel storage tank supports	2, 6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule

Table 3.6-5 Intake Structure					
Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
CONCRETE (Sub-materials: Non-shrink Grout, Epoxy Grout, Embedments[B], and Reinforcement[B])					
Building foundation (El. 322'-6")	2,6,8	Reinforced concrete	Exposed to weather	None	None
Floor slabs (El. 354' category 1 portion & El. 366')	2,6	Reinforced concrete	Protected from weather	None	None
Exterior walls, below grade (El. 322'-6" to approx. El. 354')	2,6,8	Reinforced concrete	Exposed to weather	None	None
Exterior walls, above grade (El. 354' to El. 378')	2,3,5,6	Reinforced concrete	Exposed to weather	Loss of material[F]	Maintenance Rule
Interior walls (El. 322'-6" to El. 378')	2,6	Reinforced concrete	Protected from weather	None	None
Columns and beams (El. 354' to El. 378')	2,6	Reinforced concrete	Protected from weather	None	None
Roof slab (El. 378')	3	Reinforced concrete	Exposed to weather	None	None
H&V equipment penthouse walls and roof slab (El. 378' to El. 387')	2,6	Reinforced concrete	Protected from weather Exposed to weather	None	None

Table 3.6-6 Earthen Embankments					
Component / Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Emergency cooling pond	10	Natural soils	Raw water	Loss of form	Annual Emergency Cooling Pond Sounding
Intake canal	10	Natural soils	Raw water	None	None
Discharge canal	10	Natural soils	Raw water	None	None

Table 3.6-7 Aboveground/Underground Yard Structures						
Component / Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL (Sub-materials: Welds)						
Manhole covers including threaded fasteners[N]	Category 1 electrical manholes	2,5,6	Carbon steel	Exposed to weather	Loss of material	Maintenance Rule
CONCRETE (Submaterials: Non-shrink Grout, Epoxy Grout, Embedments[B] and Reinforcement[B])						
Slab/drilled piers	Q-Condensate storage tank foundation valve & pipe trench)	2,3,5,6	Reinforced concrete	Exposed to weather	None	None
Slab	Fuel oil tank foundation	6	Reinforced concrete	Exposed to weather	None	None
Walls Floor slab Columns	Emergency diesel fuel oil storage tank vault	2 to 7	Reinforced concrete	Protected from weather	None	None
Slab	BWST foundation	2,3	Reinforced concrete	Exposed to weather	None	None
Slab	AAC diesel generator building foundation	6	Reinforced concrete	Protected from weather	None	None
Manhole covers	Category 1 electrical manholes	2,5,6	Reinforced concrete	Exposed to weather	None	None
Walls Slab	Category 1 electrical manholes	2,4,6	Reinforced concrete	Protected from weather	None	None

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
STEEL (Submaterials: Thermashield [associated with pipe supports] and Welds)						
*Piping and tubing supports[G]	Reactor building[P] Auxiliary building Intake structure Diesel fuel vault Pipe trenches	2,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule [D] ASME Section XI ISI-IWF[Q] Service Water Chemical Control[E,S]
*Pipe whip restraints	Reactor building [P] Auxiliary building	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWF[Q]
* Motor operated valve supports	Reactor building [P] Auxiliary building Intake structure Diesel fuel vault	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule ASME Section XI ISI-IWF[Q]

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Hatch frames/covers[L] (i.e., associated with HELB, watertight/flood, missile, impingement, and/or fireproof hatches)	Auxiliary building Intake structure	3,4,5, and/or 7	Galvanized steel	Protected from weather Raw water[S]	None	None
	Auxiliary building	3,4,5, and/or 7	Carbon steel	Protected from weather	Loss of material	Maintenance Rule Fire Protection • Fire Barrier Inspections
	Intake structure	3,4,5, and/or 7	Carbon steel	Protected from weather Exposed to weather Raw water	Loss of material	Maintenance Rule [D] Service Water Chemical Control[E]
	Q-CST foundation (valve pit)	3,4,5, and/or 7	Carbon steel Galvanized steel	Exposed to weather	Loss of material	Maintenance Rule
* Conduit supports	Reactor building[P] Auxiliary building Intake structure Diesel fuel vault Pipe trenches	2,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule [D] Service Water Chemical Control[E,S]

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Cable trays and supports	Reactor building[P] Auxiliary building Intake structure	2,3,6	Galvanized steel	Protected from weather Raw water[S]	None	None
	Reactor building[P] Auxiliary building Intake structure	2,3,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule Service Water Chemical Control[E,S]
* H&V duct supports	Reactor building[P] Auxiliary building	2,6	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
* Cabinets, electrical panels and supports	Reactor building[P] Auxiliary building Intake structure	2,3,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule [D] Service Water Chemical Control[E,S]
* Equipment supports	Reactor building [P] Auxiliary building Intake structure	2,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule [D] ASME Section XI ISI-IWF[Q] Service Water Chemical Control[E,S]

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Hazard barrier curbs	Auxiliary building Intake structure	7	Carbon steel	Protected from weather	Loss of material	Maintenance Rule
* Banding for 10CFR50.48-required fire wraps[O]	Reactor building [P] Auxiliary building Turbine building [I]	2,6	Carbon steel	Protected from weather	Loss of material	Fire Protection: • Fire Barrier Inspections
	Reactor building[P] Auxiliary building Turbine building [I]	2,6	Galvanized steel	Protected from weather	None	None
* Fire damper mountings[H, J] (10CFR50.48-required)	Auxiliary building Intake structure Diesel fuel vault Turbine building[I]	4	Galvanized steel	Protected from weather	None	None

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Fire hose reels (10CFR50.48-required)	Reactor building[P] Auxiliary building Intake structure Turbine building[I]	2,6	Carbon steel	Protected from weather	Loss of material	Fire Protection : • Fire Hose Station Inspections
	Reactor building[P] Auxiliary building Intake structure Turbine building[I]	2,6	Galvanized steel	Protected from weather	None	None
THREADED FASTENERS [N](Sub-materials: Structural Bolts, Expansion Anchors, and Undercut Anchors)						
*Threaded fasteners[T] on: Piping and tubing supports Pipe whip restraints MOV supports Conduit supports H&V duct supports Cabinets, electrical panels and supports Equipment supports Hazard barrier curbs	Reactor building[P] Auxiliary building Intake structure Diesel fuel vault Pipe trenches	2,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule[D] Service Water Chemical Control[E,S] ASME Section XI ISI-IWF[Q]

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
*Threaded fasteners[T] for: hatch frames/covers	Auxiliary building Intake structure Q-CST foundation (valve pit)	2,6	Carbon steel	Protected from weather Exposed to weather Raw water[S]	Loss of material	Maintenance Rule[D] Fire Protection : • Fire Barrier Inspections Service Water Chemical Control[E,S]
			Galvanized steel	Protected from weather Raw water[S]	None	None
				Exposed to weather	Loss of material	Maintenance Rule
* Pipe lugs	Reactor building[P] Auxiliary building Intake structure Diesel fuel vault Pipe trenches	2,6	Stainless steel	Protected from weather	None	None
	Intake structure	2,6	Stainless steel	Raw water	Loss of material Cracking	Maintenance Rule[D] ASME Section XI ISI-IWF[Q] Service Water Chemical Control[E]

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Tubing clips	Reactor building[P] Auxiliary building Intake structure Diesel fuel vault Pipe trenches	2,6	Stainless steel	Protected from weather	None	None
	Intake structure	2,6	Stainless steel	Raw water	Loss of material Cracking	Maintenance Rule [D] ASME Section XI ISI-IWF[Q] Service Water Chemical Control[E]
* Threaded fasteners for: Cable trays and supports	Reactor building[P] Auxiliary building Intake structure	2,6	Carbon steel	Protected from weather Raw water[S]	Loss of material	Maintenance Rule [D] Service Water Chemical Control[E,S]
			Galvanized steel	Protected from weather Raw water[S]	None	None
* Threaded fasteners for: Fire damper mountings	Auxiliary building Intake structure Diesel fuel vault Turbine building[I]	2,6	Galvanized steel	Protected from weather	None	None

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
* Threaded fasteners for: Fire hose reels	Reactor building[P] Auxiliary building Intake structure Turbine building[I]	2,6	Carbon steel	Protected from weather	Loss of material	Fire Protection: • Fire Hose Station Inspections
			Galvanized steel	Protected from weather	None	None
CONCRETE (Sub-materials: Non-shrink Grout, Epoxy Grout, Embedments[B], and Reinforcement[B]						
* Equipment pads and foundations	Reactor building[P] Auxiliary building Intake structure	2,6	Reinforced concrete	Protected from weather	None	None
* Hatch covers/plugs[L] (i.e., associated with HELB, watertight/flood, missile, impingement, and/or fireproof hatches)	Auxiliary building Intake structure Diesel fuel vault BWST foundation	3,4,5 and/or 7	Reinforced concrete	Protected from weather Exposed to weather[S]	None	None

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
FIRE BARRIERS						
* 10CFR50.48-required Fire wraps[J] (spray-applied, trowelled-on, or wrapped onto members)	Reactor building[P] Auxiliary building Turbine building[I]	4	3M-wrap Monokote coating Pyrocrete coating Metal lathe and plaster Ceramic fiber blanket	Protected from weather	Loss of material Cracking/ delamination Change in material properties[U]	Fire Protection: • Fire Barrier Inspections
* 10CFR50.48-required Fire stops[J] (penetration sealant)	Reactor building[P] Auxiliary building Diesel fuel vault Turbine building[I]	4	Silicone foam Grout Boot	Protected from weather	Loss of material Cracking/ delamination/ separation Change in Material properties[U]	Fire Protection : • Fire Barrier Inspections

Table 3.6-8 Bulk Commodities						
Component/ Commodity Grouping	Structure	Intended Function	Material	Environment	Aging Effect	Program/Activity
ELASTOMERS						
Waterstops at construction joints of exterior concrete walls	Reactor building Auxiliary building Diesel fuel vault Q-CST foundation (valve pit & pipe trench)	8	Rubber Polyvinyl-chloride Neoprene	Protected from weather	None	None
TEFLON						
* Piping support restraints	Reactor building[P] Auxiliary building	2,6	Polytetra-fluoroethylene	Protected from weather	Change in material properties	Maintenance Rule ASME Section XI ISI-IWF[Q]
* Equipment pad/ foundation plates	Reactor building[P] Auxiliary building	2,6	Polytetra-fluoroethylene	Protected from weather	Change in material properties	Maintenance Rule ASME Section XI ISI-IWF[Q]

3.7 Electrical and Instrumentation and Controls

This section discusses the passive electrical component types that were initially scoped and met the screening criteria of Section 2.5. The potential aging effects are evaluated to determine their applicability to the components subject to aging management review. Table 3.7-1 lists the aging effects for passive electrical components that require aging management.

3.7.1 Aging Management Review Methodology

This review follows the "plant spaces" approach and methodology as described in Sandia Report SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations" (Reference 3.7-1). As described in this report, Sandia evaluated aging mechanisms and consolidated historical maintenance and industry operating information into one source. The report contains the following primary conclusions.

- Cables and terminations that are included in the scope of aging management review are highly reliable and can be expected to perform their safety function during the initial license term and for license renewal.
- Based on the analysis of failure data, the number of cable and termination failures that have occurred throughout the industry is extremely low in proportion to the general population.
- The stressors and aging mechanisms affecting cables and terminations are generally well understood and characterized.
- Cable aging can be evaluated on an on-going basis, using theoretical techniques, measurement of physical properties, and periodic inspection.

The Sandia report concluded that detailed component level review was only required for those passive electrical components which are located near heat or radiation sources, are subject to continuous or near continuous loading at a significant percentage of the cable ampacity limits, are exposed to wetting (medium voltage only) or adverse chemical environments, or are subject to repeated or damaging mechanical stress. Low voltage instrument circuits that are sensitive to small variations in impedance were also determined to be potentially affected by oxidation of connector or termination contacts. The Sandia report also recommended that special consideration should be given to the possibility of installation damage to cables and electrical equipment.

Heat stress can cause accelerated aging for some passive electrical components and is primarily a concern for cable insulation. The Sandia report recommended the identification of a service-limiting temperature threshold that does not exceed the 60-year service-limiting temperature applicable to the materials of concern. For ANO-1, temperature thresholds of 105^0F outside of the reactor building and 120^0F inside the reactor building have been chosen in the ANO-1 EQ program for the ambient temperatures assumed in aging analyses. For the purposes of license renewal evaluations, ANO-1 has also chosen the service-limiting temperature thresholds of 105^0F outside of the reactor building and 120^{0}F inside the reactor building to be consistent with the ambient temperature assumptions in the ANO-1 EQ program.

The EQ system component evaluation worksheets represent a broad database of material evaluations and provide a qualified source for verification of material properties. Therefore, as long as the temperature of an area remains below these thresholds, further evaluation of the heat stress and thermal aging of the passive electrical components in that area is not required to support license renewal. As noted in the Sandia report, the service-limiting temperature threshold is not meant to be an absolute maximum since small, short term temperature excursions above the service-limiting temperature (such as during particularly hot summer days) will not significantly affect material aging.

Cables subject to aging management review that are not in the ANO EQ program are similar to those that are covered by the EQ program. The majority of EQ cables at ANO-1 have been tested and qualified to at least 2.0×10^8 rads. For the license renewal evaluation, a total integrated dose of 1.0×10^8 rads will be established as the radiation dose threshold level of concern for cables and cable terminations that are not in the EQ program scope.

Cables that are operated continuously near their current carrying capacity will operate closer to their temperature limits due to ohmic heating. This is an important concern for power cables only and does not affect instrumentation or low voltage control cables due to their low operating currents. For ANO-1, cables are sized with conservative margins for their current carrying capacities, insulation properties, and mechanical construction. The ANO-1 base capacity rating of cable is normally as conservative or more conservative than that established in published IPCEA standards. Only a small portion of the major "Q" equipment is continuously in service during normal plant operation. Cables that are operated continuously at a significant percentage of their current carrying capacity during normal plant operation have been identified and are evaluated in Section 3.7.6

The majority of the cables at ANO-1 are located in dry locations inside plant structures and are not exposed to an adverse chemical environment. ANO-1 is located on a fresh water inland lake and is not exposed to saltwater. The cables that are potentially exposed to wet conditions or chemical environments have been identified and are evaluated in Section 3.7.6.

The passive electrical components that are exposed to repeated mechanical stress are those cables and connectors that must be periodically moved or disconnected from equipment for plant outages or surveillance testing. These have been identified and are evaluated in Sections 3.7.4, 3.7.5, and 3.7.6.

Low-voltage instrument cables and connectors that operate at low currents or are otherwise sensitive to small variations in impedance have been identified and are evaluated in Sections 3.7.4 and 3.7.6.

3.7.2 Review of ANO-1 Plant Spaces

The main structures that house passive electrical equipment within the scope of license renewal are the reactor building, the auxiliary building, the turbine building, and the intake structure. There are also a limited number of passive electrical components in specialized structures such as the fuel oil storage vault and duct banks and manholes. The following discusses the ambient conditions in each of these structures.

3.7.2.1 ANO-1 Reactor Building

The "Q" equipment housed in the reactor building that is required to function under accident conditions includes the reactor, the reactor coolant system, the reactor building coolers, and hydrogen recombiners. A wide variety of instrumentation systems have sensors inside the reactor building which are required to be available under accident conditions. During normal plant operation the reactor building is cooled by recirculating air through coolers located inside the reactor building.

In response to elevated reactor building temperatures identified at ANO-1 in 1987, a thermal aging assessment was completed for the electrical equipment in the reactor building. This evaluation documented the impact of increased reactor building temperatures at various elevations and locations. The reactor building temperature has since decreased with the installation of additional insulation on the RCS and a new reactor building cooling unit. The corrective actions taken have returned reactor building general area temperatures back to 120^0F, or less.

Since ambient temperature in portions of the reactor building are above the 120^0F threshold value chosen for evaluation of thermal aging, passive electrical components in those areas of the reactor building have been identified and are evaluated in Sections 3.7.4 through 3.7.6.

3.7.2.2 ANO-1 Auxiliary Building

The auxiliary building houses nearly all of the major "Q" electrical switchgear and electrical "Q" components (station batteries, inverters, transformers, chargers, etc.) as well as the majority of the "Q" pumps and valves. During normal plant operation, the majority of the auxiliary building is supplied with outside air from the supply fans that is cooled or heated as necessary and exhausted by the area exhaust fans. Separate ventilation systems are provided for potentially radioactive areas. A number of individual room exhaust fans and cooling units are provided. This equipment is designed to maintain the general auxiliary building areas (not including the EDG room, SFP/fuel handling area, or control room) less than 105^0F during the summer.

The EDG rooms are equipped with exhaust fans that provide once through cooling to ensure the room temperature does not become excessive when the diesel generators are running. The service water system cools the EDG jacket water system. The room cooling only has to remove the EDG heat load. Since the EDGs are normally not running, room temperatures are normally low.

The spent fuel pool and fuel handling area has its own ventilation equipment that supplies outside air for cooling as required. The SFP area air temperature is not expected to increase significantly above the outdoor temperature, therefore excessive temperatures do not occur in this area.

The control room cooling units maintain a comfortable environment for the operators and cool the control room equipment. The temperature in the control room is normally maintained well below 105^{0}F, therefore this is a very mild environment for passive electrical equipment.

Walkdowns were performed in the ANO-1 auxiliary building to determine if the general area temperatures in the auxiliary building are normally maintained at less than 105^{0}F. Thermography surveys were completed for the rooms in the auxiliary building to collect additional data on the ambient temperatures and to detect areas with elevated temperatures. Cable trays were also surveyed. Components located in areas where the temperature exceeds 105^{0}F have been identified and are evaluated in Sections 3.7.4 through 3.7.6.

3.7.2.3 ANO-1 Turbine Building

The turbine building primarily houses non-Q equipment associated with electrical generation and not necessary for plant safety. The turbine building is cooled by supply and exhaust fans to provide once through cooling by the outside air. The lower levels of the turbine building are relatively cool. The upper portions of the turbine building and portions near the steam and feedwater piping can have elevated temperatures. In a few areas, Q cables in conduit are mounted in the turbine building or pass through the lower levels of the turbine building in their routing to the intake structure.

Walkdowns were performed in the ANO-1 turbine building to determine if the general area temperatures in the turbine building are normally maintained at less than 105^{0}F. Thermography surveys were completed for the turbine building to collect additional data on the ambient temperatures and to detect areas with elevated temperatures. Cable trays were also surveyed. Components in ambient temperatures above the 105^{0}F threshold have been identified and are evaluated in Sections 3.7.4 through 3.7.6.

3.7.2.4 ANO-1 Intake Structure

The intake structure houses the service water pumps and motors, the disconnect switchgear for the swing SW pump, the SW discharge header valves, several "Q" motor control centers, the fire pumps and their associated controls, a non-Q lighting panel, a non-Q power panel, and a non-Q cathodic protection rectifier. The intake structure is cooled by exhaust fans during normal plant operation to provide once through cooling by the outside air. The lower level of the intake structure has few heat loads, and is expected to remain at essentially the outdoor ambient temperature during summer operation due to the high flow rate of outside air through this level.

The intake structure ventilation system has been sized to maintain the maximum upper level area temperature at less than 105^{0}F with an outside air temperature of 95^{0}F. Although, under accident conditions, the exhaust fan could be lost and temperatures could be temporarily elevated (natural convection has been shown to provide adequate cooling), this accident condition does not impact the normal equipment aging environmental conditions. The outside air temperature can also exceed 95^{0}F during summer operation, but the duration is not significant when evaluating the average yearly conditions.

Walkdowns were performed in the ANO-1 intake structure to determine if the general area temperatures in the intake structure are normally maintained at less than 105^0F. Thermography surveys were completed for areas within the intake structure to collect additional data on the ambient temperatures and to detect areas with elevated temperatures. Cable trays were also surveyed. Components that have ambient temperatures above the 105^0F threshold have been identified and are evaluated in Sections 3.7.4 through 3.7.6.

3.7.2.5 Fuel Oil Storage Vaults

The underground fuel oil storage vaults contain the safety grade fuel oil storage tanks and the fuel oil transfer pumps for the emergency diesel generators. The vaults have no significant heat loads and are provided with exhaust fans to provide fresh air ventilation. The vault temperature remains cool year round due to the heat transfer to the ground and the lack of significant heat loads. Walkdowns have been performed in the fuel oil storage vaults to determine if the general area temperatures are maintained at less than 105^0F. Thermography surveys confirmed this to be the case. Therefore, the fuel oil storage vaults do not expose equipment to an excessive temperature and are not expected to have any passive electrical components in the scope of license renewal that are above the 105^0F threshold value chosen for evaluation of thermal aging.

3.7.2.6 ANO-1 Main Steam Line Area (Penthouse)

The main steam line area is cooled by two exhaust fans to provide once through cooling by outside air. The main steam line area (Room 170), located on elevation 404', comprises the main steam isolation valve room and the main steam safety valve room. Within the main steam safety valve room, higher equipment elevations are accessible only by ladder. Thermography surveys were conducted in these areas during plant walkdowns. For the components in these areas that are exposed to temperatures that exceed 105^0F, further evaluation is provided in Sections 3.7.4 through 3.7.6.

3.7.2.7 AAC Diesel Generator Building

The equipment purchased for the AAC diesel generator was specified to have a design life of 40 years, which will envelope the extended license period. Nevertheless, walkdowns of the AAC generator building were performed and thermography surveys of the area were conducted. No areas with elevated temperatures were detected in the AAC diesel generator building.

3.7.3 Summary of the Plant Spaces Screening

Passive electrical components in the portions of the reactor building, where the ambient temperature is above the 120^{0}F license renewal threshold value, or the high radiation threshold value is exceeded, are evaluated. The auxiliary building and intake structure are controlled environments that are mostly benign spaces for the passive electrical equipment in the scope of license renewal. For the few areas in the auxiliary building that have equipment temperatures above the 105^{0}F threshold value, the passive electrical components are evaluated. The passive electrical components in the turbine building that are above the 105^{0}F threshold value are evaluated. Therefore, using the plant spaces approach, the Sandia selection of significant stressors, and NEI 95-10 (Reference 3.7-2) passive component categorization, the following subsets of passive electrical components within the scope of license renewal and subject to aging management review require component specific evaluation.

- Passive electrical equipment in elevated temperature locations
- Passive electrical equipment in areas of the reactor building that are above the threshold radiation level
- Wetted medium voltage power cables and cables exposed to potentially hazardous chemicals
- Power cables loaded above a significant fraction of their ampacity rating (significant fraction is defined as 50% of the ampacity rating)
- Cables and connectors subject to frequent manipulation (frequent is defined as being disconnected/reconnected more than once per refueling cycle)
- Low voltage instrument cables and connectors that operate at low currents or are otherwise sensitive to small variations in impedance

3.7.4 Connectors

Potential aging mechanisms that were considered for ANO-1 connectors include corrosion of metals, electrical stresses, water or humidity effects, mechanical stresses (including wear), and thermal or radiation aging of the organic components. During normal plant operation, the plant connectors are exposed primarily to dry conditions, and significant corrosion is not expected. The connectors do not provide any substantial mechanical support, and therefore mechanical stresses are not significant. The electrical stress of most connectors is insignificant, since the connectors are large in relation to the actual current carrying capacity. The organic portions of connectors (such as insulating materials, O-rings, filler materials, cases, etc.) are susceptible to aging from both thermal and radiation exposure. Frequent manipulation can cause wear on the surfaces in contact and loosen the sealing material or the cases.

A small number of splices have been identified as being subject to the aging effects discussed in the Sandia report. Moisture and elevated temperatures are the stressors for the splices identified. In order to manage the aging effects on these splices and demonstrate acceptable performance during the extended license term, an Electrical Component Inspection Program will be established to inspect and monitor the condition of the identified splices. This program is described in detail in Appendix B.

Connectors that are subject to frequent manipulation have been identified. The connector types identified consist of terminal blocks, multi-pin connectors, screw terminals, and battery terminal posts. Terminal blocks are addressed in the next section. For the other connector types, ANO-1 will rely on good maintenance practices to ensure that frequent manipulation does not unacceptably degrade connectors during the extended license term. Inspections of connectors are completed during the reconnection of connectors following any maintenance that required the connector to be disconnected. The effects of frequent manipulation (wear, loose fittings, cracking, etc.) are easily detected by visual inspections. Electrical checks of many vital functions are performed after reconnection of connectors to verify continuity. Therefore, no additional measures are necessary to manage aging for these connectors.

Connectors that are terminating impedance sensitive circuits have been identified. This group consists of coaxial and triaxial connectors. Oxidation or corrosion of the connector pins could interfere with the operation of these circuits. In order to ensure this does not happen, an Electrical Component Inspection Program will be established to periodically inspect these connectors. This program will ensure the proper operation of these circuits during the period of extended operation. This program is described in Appendix B.

3.7.5 Terminal Blocks

Potential aging mechanisms that were considered for ANO-1 terminal blocks include corrosion of exposed metal surfaces, electrical stresses, mechanical stresses, and thermal or radiation aging. Corrosion of an exposed metal surface is possible, especially in a high humidity environment, at the terminal lug to cable interface and on the terminal block. At ANO-1, no terminal blocks subject to aging management review are located in a high humidity environment and thus corrosion of terminal blocks is not a significant aging effect. No deterioration from electrical stresses is expected in terminal blocks since the current carrying capability is typically much larger that the actual current. The terminal blocks are not utilized as structural members and the mechanical stresses are too low to cause significant aging effects. Organic portions of the terminal blocks (such as insulating materials, filler materials, etc.) can be susceptible to aging from both thermal and radiation exposure. Phenolic material is very resistant to aging from elevated temperature or radiation. For example, terminal block manufacturer, Buchanan, lists 302^0F as a maximum continuous service temperature. The EPRI Data Bank qualifications for radiation for the General Electric or the Buchanan terminal blocks are over 10^8 rads. It can be concluded that thermal or radiation aging is not a significant aging effect for the phenolic terminal blocks at ANO-1.

Numerous terminal blocks subject to aging management review and subject to various aging effects have been identified. One terminal block was found in an area where it would be exposed to elevated temperatures. The aging effect for the remaining terminal blocks is damage due to frequent manipulation of the wires connected to the blocks.

As noted previously, terminal blocks are highly resistant to aging from elevated temperature. Testing of terminal blocks of the type used at ANO-1 demonstrates a qualified life significantly longer than the license renewal term. The terminal block identified above is only exposed to elevated temperature and not exposed to moisture or hazardous chemicals. Therefore, no additional actions are necessary to demonstrate the integrity of this terminal block through the period of license renewal.

The terminal blocks that are subject to frequent manipulation have been identified. Periodic maintenance and surveillance procedures call for the lifting of leads from terminal blocks for testing purposes. These same procedures require that the leads are reconnected and an independent verification performed. Good maintenance practices are relied upon at ANO-1 to ensure that frequent manipulation of the connections does not degrade any terminal block during the license renewal term. Therefore, no additional measures are necessary to manage the aging of terminal blocks.

3.7.6 Cables

Cable aging effects considered include corrosion of conductors, electrical stresses, water and humidity effects, thermal and radiation aging, and mechanical stresses. Corrosion of conductors is not expected since the conductors are covered by insulation. Deterioration of low voltage cables from electrical stress is not expected since the electrical stresses on the insulation are very low with respect to the material capabilities.

Ohmic heating can be significant for those cables that are routinely or continuously operated with high currents relative to their ampacity limits. The majority of the emergency equipment loads are only placed in operation following the initiation of an accident, therefore the "Q" switchgear cables, load center transformers, load centers and motor control centers are normally loaded to a small percentage of their rating. The essential 4.16 kV switchgear is normally energized from a non-Q supply and the "Q" supply from the emergency diesel generators is not normally in service.

Exposure to a wetted environment can be a significant aging effect for medium or high voltage cables. Water and humidity effects are not a concern for the majority of the cables at ANO-1 because they are located in dry environments. The cables that are buried underground could be exposed to a wetted environment. The aging effects of moisture intrusion, water treeing, or contamination could result in the effect of a reduced insulation resistance to ground and a potential electrical failure.

Chemical attack of organic materials used in cables may occur due to the exposure to hydraulic fluids, fuel oils, and lubricating oils or other chemicals. Significant differences exist between the chemical resistance of different types of insulation. Details on the compatibility of cables with chemical agents can be found in Table 4-6 of the Sandia Report. The cables are most likely to be exposed to the chemicals through leaks or spills. The effects of exposure to chemicals could be a softening, flowing, cracking, or discoloration of the insulation or jacket that could result in the effect of a reduced insulation resistance to ground and a potential electrical failure of the circuit.

Thermal aging of cables affects the organic materials in the insulation and can cause embrittlement, cracking, or discoloration of the insulation through thermal oxidation. This could result in the effect of a reduced insulation resistance to ground and a potential electrical failure.

Radiation stress is only significant for cables exposed to cumulative exposures of greater than the selected threshold of $1x10^8$ rads. Radiation exposure of cables will affect the organic materials in the insulation and can cause embrittlement, cracking, swelling, or discoloration of the insulation through thermal oxidation. This could result in the effect of a reduced insulation resistance to ground and a potential electrical failure. Cables subject to aging management review will not reach the radiation threshold, and thus, radiation aging is not a significant aging effect for ANO-1 cables.

Mechanical stresses in the cable systems will not change significantly during the license renewal period. Installation practices at ANO-1 and operating experience indicates that insulation cut through is not a concern. The Bechtel cable installation procedures in place during initial plant construction and the current ANO cable installation procedures should prevent cable damage during installation. Therefore, mechanical stress is not considered an aging effect requiring management for ANO-1 except for those cables that are frequently manipulated. Cutting, chafing abrasion, or splitting could occur and result in the effect of a reduced insulation resistance to ground and a potential electrical failure. In order to determine the cables and connectors that are frequently manipulated, a review of the maintenance procedures and interviews with maintenance personnel were completed. The cables that are frequently manipulated are primarily those with connectors, although some terminate on terminal blocks.

Low voltage control and instrument circuits degrade primarily because of environmental influences. Circuit electrical loading is not an aging effect in these applications due to the extremely low currents. Oxidation of connector or termination contacts may have an impact on the impedance sensitive circuits. The effect would be an increase in the circuit resistance and a reduction in the signal strength.

Cables that are in the scope of license renewal and are exposed to the various aging effects have been identified. To ensure that the aging effects due to these various conditions do not degrade the ability of these cables to function, an Electrical Component Inspection Program will be established in order to monitor the condition of the cables for the period of extended operation. The program will periodically inspect the cables and document the results for trending purposes. This program is described in detail in Appendix B.

Cables that are in the scope of license renewal and subject to frequent manipulation have been identified. The connectors and terminal blocks to which these cables are terminated are discussed in previous sections. This discussion on managing aging effects for connectors also applies to the cables that are frequently manipulated. Inspections of these cables are completed during the reconnection process. The effects of frequent manipulation are easily detected by visual inspections. Therefore, no additional measures are necessary to manage aging of these cables.

The cables used in impedance sensitive circuits have been identified. The aging effect that needs to be considered for impedance sensitive circuits is corrosion of the connectors. The connectors in this category were discussed in a previous section. The cables do not have an aging effect that can impact the operation of the circuit in terms of impedance changes. Therefore, there is no need to consider these cables further.

3.7.7 Industry and Operating Experience

Industry and operating experience have been reviewed to ensure no additional aging effects exist beyond those discussed herein. This review was performed for cables, connectors, splices, and terminal blocks. No unique aging effects for these components were identified from this review.

3.7.8 References for Section 3.7

3.7-1 SAND 96-0344, *"Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations,"* Sandia National Laboratories for the U.S. Department of Energy, September 1996.

3.7-2 NEI 95-10, *"Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule,"* Revision 0, Nuclear Energy Institute, March 1996.

Table 3.7-1 Passive Electrical Components					
Component / Commodity Grouping	Intended Function	Material	Environment	Aging Effect	Program/Activity
Splices	Connect cable conductors to other cables.	Raychem splice kit, Raychem cable splices, Okonite insulating tape, Raychem heat shrink tape sealant	Moisture, Elevated Temperature	Reduced insulation resistance, embrittlement, and cracking	Electrical Component Inspection
Connectors	Connect cable conductors to other cables or electrical devices.	Polysufone, Kapton, EPDM, CSPE	Moisture, Elevated Temperature	Reduced insulation resistance, embrittlement, cracking, and electrical failure	Electrical Component Inspection
Terminal Block	Connect cable conductors to electrical devices.	Phenolic	Elevated temperature	NA	NA
Cables	Provide electrical connection between two sections of an electrical circuit.	XLPE, EPR, FR-EP, CPE, CSPE, FR-EPDM, Okoprene, Okoguard, Okolon, Okonite-FMR, SR	Moisture, Elevated Temperature, Ohmic Heating, Corrosive Chemicals	Reduced insulation resistance, embrittlement, cracking, and electrical failure	Electrical Component Inspection

4.0 TIME LIMITED AGING ANALYSES

As discussed in Section 1.0, two areas of technical reviews are required to support an application for a renewed operating license. The first area of technical review is the ANO-1 Integrated Plant Assessment, which is described in Sections 2.0 and 3.0. The second area of technical review required for license renewal is the identification and evaluation of plant-specific time-limited aging analyses and exemptions, which are provided in this section. The identification and evaluations contained in this section meet the requirements contained in 10CFR54.21(c) and allow the NRC to make the finding contained in 10CFR54.29(a)(2).

4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

4.1.1 Process Overview

10CFR54.21(c) requires an evaluation of time-limited aging analyses be provided as part of the application for a renewed license. Time-limited aging analyses are defined in 10CFR54.3 as those licensee calculations and analyses that meet six specific criteria. The process used to identify the ANO-1 specific time-limited aging analyses is consistent with the guidance provided in NEI 95-10 (Reference 4.1-1

To assure that the ANO-1 time-limited aging analyses were identified, several document sets were searched. ANO-1 specific documents that were reviewed for time-limited aging analyses include the ANO-1 licensing correspondence file, the ANO-1 SAR, B&W topical reports referenced in correspondence and in the SAR, and ASME Section XI Summary Reports.

The identified calculations and analyses were reviewed to determine those that meet the six criteria of 10CFR54.3. The analyses and calculations that meet the six criteria are the ANO-1 specific time-limited aging analyses, which are listed in Table 4.1-1. The reactor vessel neutron embrittlement analyses are evaluated in BAW-2251A and is discussed in Section 4.2. Metal fatigue is applicable to Class 1 components and is discussed in Section 4.3. Environmental qualification is discussed in Section 4.4. Reactor building tendon prestress is discussed in Section 4.5. Fatigue of the reactor building liner plate and reactor building penetrations is addressed in Section 4.6. Boraflex is discussed in Section 4.7. Other time-limited aging analyses are discussed in Section 4.8.

As required by 10CFR54.21(c)(1), an evaluation of ANO-1 specific time-limited aging analyses must be performed to demonstrate that

- the analyses remain valid for the period of extended operation, or
- the analyses have been projected to the end of the period of extended operation, or
- the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.1.2 Identification of Exemptions

10CFR Part 54 also requires that the application for a renewed license include a list of current plant-specific exemptions granted pursuant to 10CFR50.12 that are based on time limited aging analyses as defined in 10CFR54.3. No 10CFR50.12 exemptions involving a time-limited aging analysis as defined in 10CFR54.3 are required during the period of extended operation.

4.1.3 References for Section 4.1

4.1-1. NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10CFR Part 54 – The License Renewal Rule," Revision 0, Nuclear Energy Institute, March 1996.

Table 4.1-1 List of ANO-1 Time-limited Aging Analyses		
Component/Subject	**TLAA**	**Section of ANO-1 LRA where TLAA is addressed**
Reactor Vessel	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
	BAW-1511 (USE)	Section 4.2
	BAW-1895 (RT_{PTS})	Section 4.2
	BAW-2143P (USE & RT_{PTS})	Section 4.2
	BAW-2148 (USE)	Section 4.2
	BAW-2166 (USE & RT_{PTS})	Section 4.2
	BAW-2178 (USE)	Section 4.2
	BAW-2192 (USE)	Section 4.2
	BAW-2222 (USE & RT_{PTS})	Section 4.2
	BAW-2257 (USE)	Section 4.2
	BAW-10013 (Intergranular Separations)	Section 4.8
	BAW-10018 (Thermal Shock)	Section 4.2 No Longer Applicable—See BAW-2251A
	BAW-10051 (FIV Analysis)	Section 4.8
RCS Piping	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
	BAW-1847 (Leak Before Break Analysis)	Section 4.8
	BAW-2127 (final evaluation of surge line thermal stratification)	Section 4.3
	BAW-2085 (preliminary evaluation of surge line thermal stratification)	Section 4.3
Reactor Vessel Internals	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
	BAW-10051 (FIV Analysis)	Section 4.8
	BAW-10008 (Stress and Deflection Analyses)	Section 3.5, Appendix B
Reactor Coolant Pumps	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3

Table 4.1-1 List of ANO-1 Time-limited Aging Analyses		
Component/Subject	**TLAA**	**Section of ANO-1 LRA where TLAA is addressed**
Steam Generator	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
	BAW-1823 (for sleeves) related to metal fatigue	Section 4.3
	BAW-2120 (for sleeves) related to metal fatigue	Section 4.3
	BAW-2005 (for sleeves) related to metal fatigue	Section 4.3
	BAW-10146 (originally BAW-1588) (for tube thickness) related to metal fatigue	Section 4.3
	BAW-10027--related to metal fatigue	Section 4.3
Control Rod Drive	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
	BAW-10047 (Sandvik flaw evaluation)	Section 4.3
Pressurizer	Metal Fatigue	Section 4.3
	Analytical Evaluation of Flaws	Section 4.3
Concrete Reactor Building Tendon Prestress	ACI 318-63 ANO-1 SAR, Section 5.2.4.2.1.	Section 4.5
Reactor Building Liner Plate and Penetrations-Fatigue	The ANO-1 SAR Section 5.2.1.4.7.3 describes the fatigue review that was performed for the ANO-1 reactor building liner plate and penetrations	Section 4.6
Spent Fuel Racks Boraflex	Boraflex Degradation	Section 4.7
Environmental Qualification of Electrical Equipment	Qualified Life	Section 4.4
Reactor Coolant Pump Motor Flywheels	Analytical Evaluations of Flaws	Section 4.8

4.2 Reactor Vessel Neutron Embrittlement

Entergy Operations participated in a BWOG effort that developed a series of topical reports to demonstrate that the aging effects for reactor coolant system components are adequately managed for the period of extended operation. One of the BWOG topical reports is BAW-2251A, "Demonstration of the Management of Aging Effects for the Reactor Vessel" (Reference 4.2-1). This topical report addresses the reactor vessel. Time-limited aging analyses applicable to the reactor vessel are addressed within BAW-2251A.

The process used by Entergy Operations to incorporate BAW-2251A by reference is discussed in Section 2.3.1.2. In addition, Entergy Operations' responses to the Applicant Action Items listed in the NRC SER of BAW-2251A are provided in Table 2.3-4 of the ANO-1 LRA.

The following time-limited aging analyses are applicable to the reactor vessel.

- Thermal fatigue evaluation addressed in Section 4.3.4;
- Flaw growth acceptance under ASME Boiler and Pressure Code Section XI (Reference 4.2-2) addressed in Section 4.3.6 ;
- Neutron embrittlement of the beltline region, including pressurized thermal shock and Charpy upper-shelf energy reduction addressed in this section; and
- Intergranular separation in the heat affected zone of low alloy steel under austenitic stainless steel weld cladding addressed in Section 4.8.

The ANO-1 Reactor Vessel Integrity Program as described in Appendix B is being utilized to ensure that the time dependent parameters used in the time-limited aging analysis evaluations reported in BAW-2251A are tracked such that the time-limited aging analysis remains valid through the period of extended operation for ANO-1.

4.2.1 Pressurized Thermal Shock

10CFR50.61(b)(1) provides rules for protection against pressurized thermal shock for pressurized water reactors. Licensees are required to perform an assessment of the projected values of reference temperature whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility. For license renewal, RT_{PTS} values are calculated for 48 EFPY for ANO-1.

10CFR50.61(c) provides two methods for determining RT_{PTS}: (Position 1) for material that does not have surveillance data available, and (Position 2) for material that has surveillance data. Availability of surveillance data is not the only measure of whether Position 2 may be used. The data must also meet tests of sufficiency and credibility.

RT_{PTS} is the sum of the initial reference temperature (IRT_{NDT}), the shift in reference temperature caused by neutron irradiation (ΔRT_{NDT}), and a margin term (M) to account for uncertainties.

IRT_{NDT} is determined using the method of Section III of the ASME Boiler and Pressure Vessel Code (Reference 4.2-3). That is, IRT_{NDT} is the greater of the drop weight nil-ductility transition temperature or the temperature that is 60°F below that at which the material exhibits Charpy test values of 50 ft-lbs. and 35 mils lateral expansion. For a material for which test data is unavailable, generic values may be used if there are sufficient test results for that class of material. For Linde 80 weld material with the exception of WF-70, the IRT_{NDT} is taken to be the currently NRC accepted values of -7°F or -5°F. The ANO-1 reactor vessel does not contain any Linde 80 WF-70 weld material. For forgings and plate material, measured values are used where appropriate data is available. Where not available, the generic value of +3°F is used for forgings and +1°F is used for plate material.

For Position 1 material (surveillance data not available), ΔRT_{NDT} is defined as the product of the chemistry factor (chemistry factor) and the fluence factor. Chemistry factor is a function of the material's copper and nickel content expressed as weight percent. "Best estimate" copper and nickel contents are used which are the means of measured values for the materials. For ANO-1, best estimate values were obtained from BAW-2251A. The value of chemistry factor is directly obtained from tables in 10CFR50.61. The fluence factor value is calculated using end-of-life peak fluence at the inner surface at the material's location. Fluence values were obtained by extrapolation to 48 EFPY from the current 32 EFPY values.

For Position 2 material (surveillance data available), the discussion above for Position 1 applies except for determination of chemistry factor, which in this instance is a material-specific value calculated as follows.

- Multiply each ΔRT_{NDT} value by its corresponding fluence factor
- Sum these products
- Divide this sum by the sum of the squares of the fluence factors

The margin term (M) is generally determined as follows.

$$M = 2\,(\sigma_I^2 + \sigma_\Delta^2)^{0.5}$$

where σ_I is the standard deviation for IRT_{NDT}

and σ_Δ is the standard deviation for ΔRT_{NDT}.

For Position 1, $\sigma_I = 0$ if measured values are used. If generic values are used, σ_I is the standard deviation of the set of values used to obtain the mean value. For ΔRT_{NDT}, σ_Δ=28°F for welds and 17°F for base metal (plate and forgings), except that σ_Δ need not exceed one-half of the mean value of ΔRT_{NDT}. For Position 2, the same method for determining the σ values are used except that σ_Δ values are halved (14°F for welds and 8.5°F for base metal).

10CFR50.61(b)(2) establishes screening criteria for RT_{PTS}: 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The values for RT_{PTS} at 48 EFPY for ANO-1 are provided in Appendix A, Table A-1, of BAW-2251A. The projected RT_{PTS} values are within the established screening criteria for 48 EFPY.

By letter dated July 1, 1998 [1CAN079801 (Reference 4.2-4)], Entergy Operations submitted a response to a request for additional information for ANO-1 regarding Supplement 1 to Generic Letter 92-01, Revision 1, "Reactor Vessel Structural Integrity." The information was also contained in the BWOG topical report BAW-2325 (Reference 4.2-5). After reviewing BAW-2325, the NRC noted changes in transition temperature shift data for certain surveillance capsules and issued the BWOG several requests for additional information. Subsequent interaction between the BWOG and the staff resulted in the publication of Revision 1 to BAW-2325 (Reference 4.2-6) in February of 1999. Since BAW-2251A was completed prior to the staff's approval of BAW-2325, Revision 1, an assessment was performed relative to the staff's findings regarding chemistry factors reported in BAW-2251A. The chemistry factors reported in BAW-2251A are equivalent to or exceed the chemistry factors reported in BAW-2325, Revision 1, for the limiting beltline welds at ANO-1. In addition, ANO-1 has recalculated 48 EFPY fluence for the beltline region using the methodology described in BAW-2251A, Appendix D, and BAW-2241AP (Reference 4.2-7) and has determined that the 48 EFPY fluence estimates reported in BAW-2251A remain conservative. Therefore, the 48 EFPY RT_{PTS} values for the limiting beltline welds reported in BAW-2251A, Table A-1, remain conservative for ANO-1 since both the chemistry factors and fluence estimates remain conservative.

In order to avoid exceeding the pressurized thermal shock screening criteria at ANO-1 during the period of extended operation, Entergy Operations utilizes low leakage core designs. In addition, Entergy Operations is involved in various industry activities that provide new information or new analysis techniques associated with the reactor vessel beltline region.

4.2.2 Charpy Upper-Shelf Energy

Appendix G of 10CFR Part 50 requires that reactor vessel beltline materials "have Charpy upper-shelf energy ... of no less than 75 ft. lb. initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft. lb....." The BWOG position on upper-shelf energy for 32 EFPY is documented in responses to NRC Generic Letter 92-01, Revision 1, "Reactor Vessel Structural Integrity," as reported in BAW-2166 (Reference 4.2-8) and BAW-2222 (Reference 4.2-9). The BWOG position on upper-shelf energy for 48 EFPY is documented in BAW-2275 (Reference 4.2-10), which is included in BAW-2251A as Appendix B.

Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides two methods for determining Charpy upper-shelf energy (C_VUSE). Position 1 for material that does not have surveillance data available and Position 2 for material that does have surveillance data. For Position 1, the percent drop in C_VUSE, for a stated copper content and neutron fluence, is determined by reference to Figure 2 of Regulatory Guide 1.99, Revision 2. This percentage drop is applied to the initial C_VUSE to obtain the adjusted C_VUSE. For Position 2, the percent drop in C_VUSE is determined by plotting the available data on Figure 2 and fitting the data with a line drawn parallel to the existing lines that upper bounds all the plotted points.

The 48 EFPY C_VUSE values determined for the reactor vessel beltline materials for ANO-1 are reported in Table 4-4 of BAW-2251A. The T/4 fluence values reported in this table were calculated in accordance with the ratio of inner surface to T/4 values (i.e., neutron fluence lead factors at T/4) determined in the latest Reactor Vessel Surveillance Program report. As shown in this table, the C_VUSE is maintained above 50 ft-lb for base metal (plates and forgings); however, the C_VUSE for weld metal drops below the required 50 ft-lb. at 48 EFPY. Appendix G of 10CFR Part 50 provides for this by allowing operation with lower values of C_VUSE if "... it is demonstrated ... that the lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code."

This equivalent margin analysis was performed for 48 EFPY and the results are reported in Appendix B to BAW-2251A for service levels A, B, C, and D. The analysis used conservative materials models and load combinations, e.g., treating thermal gradient stress as a primary stress. For service levels A and B, the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code (1995 Edition). For service levels C and D, the most limiting transient was evaluated, and again the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code. The evaluations for all service levels conclusively demonstrate the adequacy of safety against fracture for the ANO-1 reactor vessel for 48 EFPY.

As discussed in the previous section, Entergy Operations submitted a response to a request for additional information for ANO-1 regarding Supplement 1 to Generic Letter 92-01, Revision 1 (Ref. 4.2-6). The copper composition reported in BAW-2251A is equivalent to or exceeds the copper content reported in BAW-2325, Revision 1. In addition, the 48 EFPY fluence estimates were redone. It was determined the fluence estimates listed in BAW-2251A remain conservative. Therefore, the C_VUSE in Table 4-4 of BAW-2251A remains conservative.

4.2.3 References for Section 4.2

4.2-1 BAW-2251A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel*," The B&W Owners Group Generic License Renewal Program, June 1996.

4.2-2 ASME Boiler and Pressure Vessel Code, Section XI, "*Rules for In-Service Inspection of Nuclear Power Plant Components*," American Society of Mechanical Engineers.

4.2-3 ASME Boiler and Pressure Vessel Code, Section III, "*Rules for Construction of Nuclear Power Plant Components*," American Society of Mechanical Engineers.

4.2-4 1CAN079801, Letter from D. James (ANO) to the NRC, "*Generic Letter 92-01, Supplement 1, Reactor Vessel Structural Integrity, Request for Additional Information*," dated July 1, 1998.

4.2-5 BAW-2325, "*Response to Request for Additional Information (RAI) Regarding Reactor Pressure Vessel Integrity – Generic Letter 92-01, Revision 1, Supplement 1*," B&W Owners Group, May 1998.

4.2-6 BAW-2325, "*Response to Request for Additional Information (RAI) Regarding Reactor Pressure Vessel Integrity*," Revision 1, B&W Owners Group, January 1999.

4.2-7 BAW-2241AP, "*Fluence and Uncertainty Methodologies*," The B&W Owners Group, April 1997.

4.2-8 BAW-2166, "*Response to Generic Letter 92-01*," B&W Nuclear Service Company, June 1992.

4.2-9 BAW-2222, "*Response to Closure Letters to Generic Letter 92-01, Revision 1*," B&W Nuclear Technologies, June 1994.

4.2-10 BAW-2275, T. Wiger and D. Killian, "*Low Upper-Shelf Toughness Fracture Mechanics Analysis of B&W Designed Reactor Vessels for 48 EFPY*," Framatome Technologies, Inc.

4.3 METAL FATIGUE

4.3.1 Background

The thermal fatigue analysis of reactor coolant components has been identified as a time-limited aging analysis for ANO-1. Specific RCS components have been designed considering transient cycle assumptions, as listed in vendor specifications and the ANO-1 SAR. For ANO-1, B&W designed the main reactor coolant system and piping. Bechtel designed the ASME Class 1 portions of the ancillary systems attached to the B&W scope of supply. The evaluation of each vendor's piping design is performed separately.

4.3.2 B&W Scope of Supply

The B&W scope of supply includes major components in the RCS and the associated interconnecting piping. Vessels were designed in accordance with ASME Section III (Reference 4.3-1), 1965 Edition, with Addenda through Summer 1967.

Reactor coolant pumps were designed in accordance with ASME Section III, 1968 edition. RCS piping supplied by B&W was designed to Nuclear Piping Code, USAS B31.7 Class 1 (Reference 4.3-2).

4.3.3 Bechtel Scope of Supply

Bechtel supplied piping includes the Class 1 portions of the ancillary systems attached to the B&W scope of supply and miscellaneous vents, drains and instrumentation lines. Ancillary systems include core flood, low pressure injection/decay heat removal, high pressure injection/makeup and purification, pressurizer auxiliary spray, pressurizer surge line low point drain, reactor coolant letdown, reactor coolant high point vent and other miscellaneous vents, drains and instrumentation piping. Bechtel supplied piping was designed to Class 1 standards of Nuclear Piping Code USAS B31.7, dated February 1968, and as corrected for Errata under date of June 1968, or later appropriate ASME Section III Code sections, provided they have been reconciled.

4.3.4 Thermal Fatigue

10CFR54.21(c) requires an evaluation of fatigue to demonstrate that either the analyses remain valid for the period of extended operation, have been projected to the end of the extended operation period, or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. ANO-1 addresses fatigue by ensuring that its effects are adequately managed for the period of extended operation. This method comprises the following activities:

- Design documentation defines the transient cycles to be monitored and the number of allowable cycles. Available documentation reflects the current plant configuration.
- Appropriate actions are taken to address significant industry fatigue concerns that were not considered in the original design. This includes issues like thermal stratification fatigue and environmentally-assisted fatigue. The ANO-1 specific review of industry experience is provided in this section.

- The actual plant transient cycles are tracked and documented to ensure the allowable number of cycles is not exceeded. The ANO-1 transient cycle monitoring program is reviewed in Section 4.3.5.

4.3.4.1 ANO-1 Fatigue Design Documentation

Fatigue evaluations were required in the design of the ANO-1 Class 1 components in accordance with the requirements specified in the applicable design codes (i.e., ASME Section III and USAS B31.7). For Class 1 components, separate discussions of fatigue are provided for the B&W-supplied components and for the Bechtel-supplied components.

4.3.4.2 B&W-Supplied Components

Design cyclic loadings and thermal conditions for the B&W-designed reactor coolant system Class 1 components are defined by the component design specifications. The RCS functional specification provides the set of transients that were used in the design of the B&W-supplied components and are included as part of each component design specification. The component design specification defines the transient cycle assumptions used in the fatigue evaluations for each component.

As a part of the GLRP effort, a review was performed to determine which Class 1 components were more sensitive to fatigue (environmentally-assisted fatigue effects were not considered in this study) and which transients caused the greatest impact in terms of fatigue stress on those components. Based on the fatigue usage factor-design transient matrices, the transients used to calculate fatigue usage factors for the B&W-supplied Class 1 components were identified. For this set of design transients, the number of transients accrued was compiled and a conservative projection was made to determine if the number of design cycles would be exceeded in the period of extended operation. In no instance, for ANO-1, did the extrapolation exceed the allowable number of design cycles prior to 60 years of operation. The existing usage factor calculations remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).

4.3.4.3 Bechtel-Supplied Piping

Design cyclic loading and thermal conditions for the Bechtel-supplied piping are defined in a Bechtel Class 1 piping design specification. Existing cumulative usage factors and analyzed thermal transients documented in thermal fatigue calculations for the Bechtel-supplied piping have been reviewed. Based on the number of transient cycles accrued for ANO-1 and the rate these cycles have been accumulated, the number of transient cycles that were originally projected for the current license of 40 years envelopes the number of cycles projected for the end of the 60-year operation.

As allowed by ASME NB-3630, for the Class 1 piping of pipe size of 1" NPS or less, ASME Subsection NC-3600 rules have generally been applied for Code qualification, using the stress range reduction factor of 1.0 for thermal fatigue stress allowables, as long as the location does not exceed 7000 full temperature thermal cycles during its operation. In order to identify the specific locations where extended operation could invalidate the existing stress range reduction factor in the piping analysis, the design temperatures and operating conditions of the ANO-1 mechanical systems were considered. These mechanical systems were reviewed to determine those likely to see 7,000 equivalent full temperature thermal cycles during plant operation. This review determined that the assumption of less than 7,000 equivalent full temperature thermal cycles is valid for the period of extended operation. The Bechtel-supplied piping has been Code qualified for the original number of design cycles which envelopes the predicted number of cycles for 60 year operation. The existing fatigue calculations remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i)

4.3.4.4 ANO-1 Response to Industry Experience on Fatigue

Industry experience has identified thermal conditions that would result in thermal fatigue stresses that were not considered in the original design evaluations. The following section discusses industry-wide thermal fatigue issues and how they have been addressed for ANO-1.

Environmentally Assisted Fatigue (NRC GSI-190)

Historically, the ASME fatigue design curves have been obtained from the results of fatigue tests on small specimens, conducted under a laboratory (air) environment. Recent laboratory test results indicate that the effects of light water reactor environments can reduce the fatigue life of RCS components. Interim fatigue curves based on this test data have been published in NUREG/CR-5999.

In a study funded by the NRC, the impacts of these interim fatigue curves on various nuclear power plant components (including ANO-1) were assessed. The results of the assessment were published in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." Based on the results of NUREG/CR-6260, the NRC initiated GSI-190, to address concerns regarding the environmental effects on operation beyond the current license term (i.e. from 40 years to 60 years).

In December 1999, in closing GSI-190 (Ref.43), the NRC concluded:

"The results of the probabilistic analyses, along with the sensitivity studies performed, the interactions with the industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is resolved. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 year to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe leaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10CFR54.21, licensees should address the effects of the coolant environment on component fatigue life as aging management programs are formulated in support of license renewal."

In summary, environmental effects have negligible impact on core damage frequency, and no generic regulatory action is required. However, environmental effects can increase the frequency of pipe leaks and licensees who apply for license renewal should address the effects of coolant environment on component fatigue life as part of their aging management programs.

An effective approach to manage this issue is to identify ANO-1 specific locations that are the most susceptible to failure from thermal fatigue, and other degradation mechanisms, and include these locations in the augmented inservice inspection program.

Section 5.3 of NUREG/CR-6260 provides the following critical component locations in B&W plants that are applicable to ANO-1.

1) Reactor vessel shell and lower head
2) Reactor vessel inlet and outlet nozzles
3) Pressurizer surge line
4) Makeup/high pressure injection (HPI) nozzles
5) Reactor vessel core flood nozzle
6) Decay heat removal system Class 1 piping

An environmentally assisted fatigue analysis for the reactor vessel was completed by the BWOG and documented in BAW-2251A (Reference 4.3-3). This study derived environmental fatigue factors based on the model described in NUREG/CR-6335, "Fatigue Strain-Life Behavior of Carbon and Low-Alloy Steels, Austenitic Stainless Steels, and Alloy 600 in LWR Environments." These factors were applied to the reactor vessel items studied in NUREG/CR-6260 (the reactor vessel shell and lower head, the vessel inlet and outlet nozzles, and the core flood nozzles). The conclusion of this analysis was that after accounting for environmentally assisted fatigue, the reactor vessel fatigue usage factors remain acceptable for the period of extended operation. Therefore, locations 1, 2, and 5 above have been resolved by analysis.

The remaining three locations (locations 3, 4, and 6) are included in the risk-informed inservice inspection (RI-ISI) program which has been recently approved by the NRC as an alternative to requirements of ASME Section XI Inservice Inspection (Reference 4.3-4). This RI-ISI program was a pilot program developed using methodology consistent with ASME Code Case N-560, "Alternative Examination Requirements for Class 1, Category B-J Piping Welds Section XI, Division 1."

The primary objective of this program was to identify the "risk important" piping segments for inspection based on analysis of the probability and the consequences of piping failures. Implementing the RI-ISI program will ensure inspections take place where degradation mechanisms (including thermal fatigue) would be most likely at ANO-1.

In summary, three of the six locations listed in NUREG/CR-6260 as most susceptible to environmentally assisted fatigue, are resolved by the BWOG engineering report BAW-2251A. The potential environmental assisted fatigue damage to the remaining three locations (pressurizer surge line, HPI nozzles and decay heat removal suction line) will be managed by the RI-ISI program through the extended operation period. Note that the ANO-1 decay heat removal suction line has been shown in NUREG/CR-6260 to be acceptable with the environmental factors applied.

<u>NRC Bulletin 88-08, Thermal Stresses in Piping Connected to Reactor Coolant Systems</u>

In response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," and Supplements 1 and 2 to this bulletin, ANO-1 reviewed 23 different piping configurations connected to the RCS. Each line was reviewed to determine susceptibility to thermal stresses. It was determined that three HPI lines and the pressurizer auxiliary spray line met the criteria of the Bulletin. During refueling outage 1R8, portions of the pressurizer auxiliary spray line were modified or replaced to eliminate the condition of thermal stratification. Additionally, a combination of dye penetrant testing, ultrasonic testing, and visual examinations of the relevant welds from the check valve to the RCS nozzle were conducted for the three HPI lines, in refueling outage 1R8. No detrimental effects of thermal stratification were found.

In addressing Supplement 3 to NRC Bulletin 88-08, ANO-1 participated with the BWOG to fund EPRI Program 3153, "Thermal Stratification in Horizontal Lines." Additional evaluation of the 23 lines was performed to consider flow from the RCS. Based on this evaluation, ANO-1 included the fourth HPI line in the NDE scope. This fourth HPI line was examined in 1R9 using the enhanced ultrasonic testing method from Supplement 2 of the bulletin. No detrimental conditions were found. A design change package was implemented to add temperature-monitoring instrumentation on the HPI lines. The decay heat system suction line from the RCS also required monitoring and evaluation due to packing leaks on an isolation valve. These actions meet the requirements of Bulletin 88-08.

Because of stratified flows in lines monitored on ANO-2, the ANO-1 systems were reviewed again, to identify systems with attributes similar to the ANO-2 stratified lines. Four lines were found to require monitoring and evaluation. They were pressurizer main spray, decay heat drop leg, reactor coolant system drains, and reactor coolant system letdown drains. Temperature monitoring and evaluations have demonstrated that these ANO-1 lines are qualified for their service conditions.

In response to Bulletin 88-08, ANO-1 committed to performing enhanced ultrasonic examinations of 17 HPI welds and visual inspection of two segments of HPI piping, as part of the ANO-1 10-year interval Inservice Inspection Plan. Subsequently, the scope of ISI inspections for the HPI lines and pressurizer surge line was modified based on an ANO-1 risk analysis performed consistent with the requirements of ASME Code Case N-560, "Alternative Examination Requirements for Class 1, Category B-J Piping Welds Section XI, Division 1". This commitment will continue through the extended period of operation of ANO-1. This issue has therefore been resolved for the extended period of operation.

<u>NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification</u>

The review of the pressurizer surge line thermal stratification concern was performed in several stages. Entergy Operations participated in a BWOG effort to review data from a B&W plant in Germany and an extensive data collection program at Oconee Unit 1. Inspections of the ANO-1 surge line determined that only snubbers were used and no rigid or whip restraints existed on the pipe that could restrict the pipe thermal movement. An elevation survey of the pressurizer surge line was performed in 1989 and the survey results indicated no bowing. Visual inspection of a vertical snubber found no damage or defect, and there was no evidence of thermal movements exceeding the travel of the snubber. A BWOG report was prepared to justify continued plant operation and present a bounding analysis. The final report was later submitted to complete the actions requested in NRC Bulletin 88-11. Based on this BWOG report, revisions of the RCS functional specification were completed to add restrictions on operating conditions for the surge line. A reanalysis was completed of the stress in the surge line drain.

The NRC has reviewed the ANO-1 responses and determined the actions taken met the requirements of the bulletin. The identified thermal stresses are now considered in the appropriate stress and fatigue calculations and this concern has been resolved.

Originally, ANO-1 committed to performing enhanced ultrasonic examinations of two elbows of the pressurizer surge line as part of ANO-1 10-year interval Inservice Inspection Plan in response to Bulletin 88-11. Subsequently, the scope of ISI inspections of the pressurizer surge line has been modified based on a ANO-1 risk analysis performed consistent with the requirements of ASME Code Case N-560, "Alternative

Examination Requirements for Class 1, Category B-J Piping Welds Section XI, Division 1". This commitment will continue through the extended period of operation of ANO-1. This issue has therefore been resolved for the extended period of operation.

<u>HPI/MU Nozzle Cracking in B&W Plants</u>

(NRC Information Notice 82-09, Cracking in Piping of Makeup Coolant Lines at B&W Plants; NRC Generic Letter 85-20, Resolution of Generic Issue 69: High Pressure Injection/Make-Up Nozzle Cracking in Babcock and Wilcox Plants; and NRC Information Notice 97-46, Unisolable Crack in High-Pressure Injection Piping)

A BWOG task force addressed potential high pressure injection/makeup nozzle cracking problems which affected B&W plants. The task force determined that the root cause of the nozzle cracking was loose thermal sleeves and that the cracks were propagated by thermal fatigue. The cracked safe-ends were MU nozzles with loose thermal sleeves. Based on the recommendations made by the task force, actions taken by ANO-1 included repair of nozzles with loose of damaged thermal sleeves, maintenance of adequate minimum flow, institution of an augmented inspection program for the nozzles, and performance of stress analysis with the modified thermal sleeves. The augmented ISI inspection of the HPI/MU nozzles is consistent with the methodology and scope of inspection recommended by the BWOG Safe-End Task Force. Ultrasonic testing of the knuckle region of the HPI nozzles every fifth refueling cycle, and radiography of the thermal sleeves will continue through the period of extended operation. These issues have, therefore, been resolved for the period of extended operation.

4.3.5 Review of ANO-1 Transient Cycle Logging Program

ANO-1 has a process to log transient history and operating transient cycles. Applicable site procedures contain the responsibilities, logging requirements, reporting requirements and transient type definitions. Guidance is provided for collection of the necessary plant data and for projection of the number of transient cycles to the end of plant life. The ANO-1 operating transient cycle logs are retained for the duration of the license, per site procedures and ANO-1 Technical Specifications.

The operational history of ANO-1 is consistent with the assumption in the GLRP reports that only evaluated level A and B events. Entergy Operations will maintain the ANO-1 Transient Cycle Logging Program through the license renewal period.

4.3.6 Flaw Growth Acceptance For ASME Section XI Inservice Inspection Program

Inservice inspections at ANO-1 have, in some cases, identified crack-like indications, primarily in welds. Indications detected during ISI that exceed acceptance criteria are either repaired, replaced or analytically evaluated to demonstrate the indications can be accepted as they are. Analytical evaluations include a crack growth analysis, based on fracture mechanics techniques, to determine the service life of the affected component. Indications that are determined not to grow beyond an acceptable limit are justified for continued operation. These crack growth analyses consider the same design transient cycle assumptions used in the original design. Since these crack growth analyses are performed using the full number of design transients cycles, which have been demonstrated to be applicable for 60 years of operation, these flaw growth calculations remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).

A relief request for successive inspection of the RCP weld flaws was written by ANO. It relied on the evaluation conducted with Code Case N-481 to provide justification. The NRC contracted the Idaho National Engineering Laboratory to evaluate the request and granted relief on January 4, 1995.

The Code Case N-481 flaw tolerance evaluation was reviewed to determine if the evaluation is acceptable for the period of extended operation. The evaluation demonstrated that the ANO-1 reactor coolant pump casings meet the safety and serviceability requirements of ASME Code Case N-481. Fatigue flaw growth and thermal embrittlement were considered in the assessment. A fatigue crack growth calculation was performed, which included an assumption of 240 heatup and cooldown cycles. Since ANO-1 has not increased the number of design transients for license renewal, the flaw growth evaluation for the pump casing is acceptable for the period of extended operation.

It has, therefore, been demonstrated that the existing results for flaw evaluations performed under the ASME Section XI Inservice Inspection program remain valid for the period of extended operation in accordance with 10CFR54.21(c)(1)(i).

4.3.7 References for Section 4.3

4.3-1 ASME Boiler and Pressure Vessel Code, Section III, *"Rules for Construction of Nuclear Power Plant Components,"* American Society of Mechanical Engineers.

4.3-2 USAS B31.7, *"Nuclear Power Piping,"* USA Standards Institute.

4.3-3 BAW-2251A, *"Demonstration of the Management of Aging Effects for the Reactor Vessel,"* The B&W Owners Group Generic License Renewal Program, June 1996.

4.3-4 1CNA089904, Letter from the NRC to C. Randy Hutchinson, *"Risk-Informed Alternative to Certain Requirements of ASME XI, Table IWB-2500-1 at Arkansas One, Unit 1 (TAC MA 2023)"*, Docket No. 50313 , dated August 25, 1999.

4.3-5 ASME Boiler and Pressure Vessel Code, Section XI, *"Rules for In-Service Inspection of Nuclear Power Plant Components,"* American Society of Mechanical Engineers.

4.3-6 W.D. Travers memorandum to A.C. Thadani, closeout of Generic Safety Issue 190, *"Fatigue Evaluation of Metal Components for 60-year plant life,"* dated December 26, 1999

4.4 ENVIRONMENTAL QUALIFICATION

Originally installed electrical equipment at ANO-1 was required to be environmentally qualified to the requirements of NRC IE Bulletin 79-01B, "Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors," commonly referred to as the Division of Operating Reactors Guidelines. ANO's Environmental Qualification Program complies with the scope of 10CFR50.49 (the EQ rule) requirements. ANO was "grandfathered" by 10CFR50.49 to allow qualification in accordance with DOR Guidelines. Therefore, the current licensing basis for the ANO EQ Program is the DOR Guidelines, as "grandfathered" by 10CFR50.49. The ANO EQ Program includes three main elements identifying applicable equipment and environmental requirements, establishing the qualification, and maintaining (or preserving) that qualification.

The first element involves establishment and control of the EQ Master List of equipment and the service conditions for the harsh environment plant areas. The second element involves establishment and control of the equipment's EQ documentation, including vendor test reports, vendor correspondence, calculations, evaluations of equipment tested conditions to plant required conditions, and determinations of configuration and maintenance requirements. The third element includes preventive maintenance processes (for replacing parts and the equipment at specified intervals), design control processes (ensuring changes to the plant are evaluated for impact to the EQ Program), procurement processes (ensuring new and replacement equipment is purchased to applicable EQ requirements), and corrective action processes (to identify and correct problems).

As a normal part of the ANO EQ process, when the EQ documentation process establishes that equipment or parts thereof, have a limited life, the preventive maintenance process ensures the equipment or parts are replaced prior to the expiration of the qualified life. If excess conservatism exists in the original qualified life determination, then reanalysis could be performed to extend the qualified life. The reanalysis utilizes standard EQ techniques (such as Arrhenius methodology), and it becomes part of the EQ documentation. Parameter conservatisms may exist in the ambient temperature of the equipment, in unrealistically low activation energy, and in the application of the equipment. The primary method used for reanalysis is reducing excess conservatism in the equipment service temperatures by using temperature values closer to an actual temperature measured in the area around the equipment being reanalyzed.

For EQ equipment with a qualified life less than the required design life of the plant, "ongoing qualification" is a method of long-term qualification involving additional testing. Ongoing qualification or retesting, as described in IEEE Std. 323-1974 (Reference 4.4-1), Section 6.6(1) or (2), is not currently considered by Entergy Operations to be a viable option, and there are no plans to implement such an option. If this option becomes viable in the future, ongoing qualification or re-testing would be performed in accordance with accepted industry and regulatory standards.

ANO-1 has some equipment that was qualified to the DOR Guidelines and other equipment that was qualified in accordance with 10CFR50.49.

The license renewal review preserves the CLB for the component. That is, if the device was originally qualified to the DOR Guidelines, the review will evaluate the extension into the license renewal period utilizing the DOR Guidelines. Each generic equipment EQ documentation file currently lists the qualification criteria applicable to the device, and this qualification criteria is assumed to be the basis of review for the evaluation of the license renewal period.

Pursuant to 10CFR54.21, methods of managing identified aging mechanisms need to be developed and implemented to provide reasonable assurance of preserving intended function(s) that may be degraded by aging. The EQ regulations from the DOR Guidelines to 10CFR50.49 contain requirements for addressing significant aging mechanisms. Therefore, EQ programs meeting these regulations are adequate for managing significant aging mechanisms for the equipment governed by the program. The ANO EQ Program addresses significant aging mechanisms.

Equipment covered by the ANO EQ Program has been evaluated to determine if existing EQ aging analyses can be projected to the end of the period of extended operation by re-analysis or additional analysis. Qualification into the license renewal period will be treated the same as equipment currently qualified at ANO for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding its qualified life in accordance with the ANO EQ Program.

EQ equipment has been reevaluated for the environmental service conditions that are applicable to the equipment (i.e., 60 years of exposure versus 40 years). The environmental service conditions are divided into two basic areas; normal and accident. For electrical equipment exposed to a harsh environment, 10CFR50.49 requires consideration of all significant effects from normal service conditions. This would include the expected thermal aging effects from the temperature to which the device is normally exposed and any radiation effects during normal plant operation. 10CFR50.49 also requires an evaluation of the effects from any harsh environments to which the equipment could be exposed under accident conditions. In general, the harsh environments that have been analyzed as part of the EQ Program were initiated by a LOCA, HELBs inside of the reactor building, and HELBs outside of the reactor building.

The evaluation of the environmental service conditions for the license renewal period requires a reevaluation of only the normal aging effects only. Therefore, the normal effects from operation for a 60-year period instead of a 40-year period will be evaluated. Radiation effects, thermal aging effects, and wear/cycle aging effects, as applicable, are analyzed for the period of extended operation. The following sections describe each of these considerations in more detail.

Radiation Considerations:

The evaluation of the license renewal period addresses radiation aging qualification. An assumption is made that the normal dose for the license renewal period will be 1.5 times (i.e., 60 years/40 years) the established dose for the 40-year period. The dose values used are based on equipment locations, applying either an inside reactor building value, outside reactor building value or application specific value. The total integrated dose for the 60-year period is determined by adding the established accident dose to the newly determined 60-year normal dose for the device. If the device was qualified for this total integrated dose, no additional review is required.

If the increase in the normal dose by this methodology results in a total integrated dose above the qualified dose for the component, a location specific review may be required to determine the specific component's total dose. Other options include requiring component or part replacement prior to exceeding the qualified total dose or performing radiation surveys to determine actual operating dose and evaluating against this value.

Some components have been installed under a plant modification, and will not experience 60 years of radiation aging by the end of the license renewal period. In some of these cases, credit may be taken for less than 60 years of aging.

Thermal Considerations:

The design temperature for the auxiliary building is 105°F except where equipment walkdowns or temperature monitoring have determined localized elevated temperatures exist. Many components in the auxiliary building are exposed to a much lower temperature than 105°F, for example below 90°F. Temperature monitoring can be utilized to confirm lower than design temperatures exist in these areas, and on that basis, extend qualified lives into the license renewal period.

The ANO-1 reactor building has experienced elevated temperatures in the past and the EQ reviews at one time used temperatures based on limited monitoring and analysis that identified increasing temperatures at the higher elevations. These temperature values have been refined by the collection of additional operating temperature data. Engineering reports are utilized to summarize this data and provide the basis for refining temperature values and equipment service lives.

If extension of the current 40-year life were chosen rather than component replacement, it would be based upon re-evaluation of current aging analysis. The aging analysis will be revised, as applicable, to identify the maximum service life based on traditional EQ techniques such as Arrhenius methodology as determined by the ANO EQ Program.

Some components have been installed under a plant modification, and will not experience 60 years of thermal aging by the end of the license renewal period. In some of these cases, credit may be taken for less than 60 years of aging.

Wear/Cycles Considerations:

The EQ evaluation of the license renewal period will address wear/cycle aging qualification. For most components, this aging does not apply; however, for electromechanical equipment like solenoid valves there would be an associated number of cycles over 40 years. An assumption is made that the number of cycles for the license renewal period would be 1.5 times (i.e., 60 years/40 years) the established number for the 40-year period.

Some components have been installed under a plant modification, and will not experience 60 years of cycling by the end of the license renewal period. In some of these cases, credit may be taken for less than 60 years of aging.

4.4.1 Allis Chalmers Motors

Four small Allis Chalmers motors are installed on the DH room coolers, located in the decay heat pump rooms.

4.4.1.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is still much less than the qualified value of 1×10^8 rads.

4.4.1.2 Thermal Considerations

The motors only experience temperatures that produce significant aging when they are in operation. Per thermal endurance analysis, the motors were shown to be qualified for 20 years of continuous operation (runtime). This is greater than the expected maximum of 12 accumulated years of operation and 28 years of non-operation at 105^0F. The 12 years of operation is sufficiently conservative to allow the units to be extended through the license renewal period since they are only operated for extended periods of time during plant shutdowns. The motors are qualified for greater than 12 years of operation (runtime) and 48 years of shutdown (non-runtime).

4.4.1.3 Wear/Cycles Considerations

The original assumption for the total number of cycles is adequately conservative to allow the device to extend through the license renewal period.

4.4.1.4 Conclusion

Allis Chalmers motor EQ aging analyses have been projected to the end of the period of extended operation.

4.4.2 Anaconda Instrumentation Cable, FR-EP Insulation

Anaconda type FR-EP instrumentation, control and power cable is used in various applications at ANO.

4.4.2.1 Radiation Considerations

The post accident dose of $4x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.2.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 160°F or 60 years at 154°F. ANO-1's high point vent valves utilize this cable with an average service temperature of 153.6°F (maximum average for these applications), while other EQ equipment using this cable is at 120°F, or below. The high point vent valves were installed in 1982 (less than 53 years needed through the end of the license renewal period).

4.4.2.3 Wear/Cycles Considerations

Not applicable to cable.

4.4.2.4 Conclusion

Anaconda instrumentation cable with FR-EP insulation EQ aging analyses have been projected to the end of the period of extended operation.

4.4.3 Anaconda Control and Power Cable, EP Insulation

Anaconda type EP low and medium voltage control and power cable is used in various applications at ANO.

4.4.3.1 Radiation Considerations

The post accident dose of $4x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.3.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 188°F or 60 years at 183°F. For ANO-1, EQ equipment using this cable is at 120°F, or below.

4.4.3.3 Wear/Cycles Considerations

Not applicable to cable.

4.4.3.4 Conclusion

Anaconda, low and medium voltage, control and power cable with EP insulation EQ aging analyses have been projected to the end of the period of extended operation.

4.4.4 Anaconda EPR Insulated Instrumentation, Control/Power Cable

Anaconda type EPR, instrumentation, control and power cable is used in various applications at ANO.

4.4.4.1 Radiation Considerations

The post accident dose of $4x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.4.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 188°F or 60 years at 183°F. For ANO-1, EQ equipment using this cable is at 120°F, or below.

4.4.4.3 Wear/Cycles Considerations

Not applicable to cable.

4.4.4.4 Conclusion

Anaconda, instrumentation, control and power cable with EPR insulation EQ aging analyses have been projected to the end of the period of extended operation.

4.4.5 ASCO Solenoid Valves, Outside Reactor Building

ASCO solenoid valves outside the reactor building are used on the air supplies to the MSIVs, the decay heat cooler bypass valves, and the service water supply valves to the decay heat and reactor building spray pump coolers.

4.4.5.1 Radiation Considerations

The accident dose for the ANO-1 applications of these components is no higher than 1.3695×10^7 rads. Adding to that the normal aging 60-year life dose of 7.95×10^3 rads results in a 1.3703×10^7 rads TID, which is still less than the qualified value of 2×10^7 rads.

4.4.5.2 Thermal Considerations

These solenoids are normally de-energized. The solenoids that are in the decay heat rooms are qualified for greater than 60 years at their normal temperature of 105°F. The solenoids for the MSIVs have a life shorter than 40 years at their temperature of 125°F, and will be replaced prior to exceeding the established life as a normal course of the ANO EQ Program.

4.4.5.3 Wear/Cycles Considerations

The devices are qualified for 40,000 cycles, which is much greater than the 3432 cycles expected over 60 years.

4.4.5.4 Conclusion

ASCO solenoid valves outside reactor building EQ aging analyses have been projected to the end of the period of extended operation for some applications while others are scheduled for replacement prior to exceeding their qualified life. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.6 ASCO Solenoid Valves, Inside Reactor Building

ASCO solenoid valves inside reactor building are used on the air supplies to the building purge valves.

4.4.6.1 Radiation Considerations

The accident dose for the ANO-1 applications of these components is 4.0×10^7 rads. Since these were just installed in 1996 we conservatively add to that the normal aging 40-year life dose of 1.0×10^7 rads which results in a 5.0×10^7 rads TID and this is still less than the qualified value of 2×10^8 rads.

4.4.6.2 Thermal Considerations

These solenoids are normally de-energized and have a life shorter than 40 years at 120°F; therefore, they will be replaced prior to exceeding the established life as a normal course of the ANO EQ Program.

4.4.6.3 Wear/Cycles Considerations

The devices are qualified for 40,000 cycles, which is much greater than the 3432 cycles expected over a 60-year period.

4.4.6.4 Conclusion

The ASCO solenoid valves inside reactor building are scheduled to be replaced prior to exceeding their qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.7 Boston Insulated Wire, Instrumentation, Control, and Power cable

Boston insulated wire, type Bostrad7 instrumentation, control, and power cable is used in various applications at ANO.

4.4.7.1 Radiation Considerations

The post accident dose of $4x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $1.0x10^8$ rads.

4.4.7.2 Thermal Considerations

The EQ documentation shows that this cable is qualified for greater than 40 years at 140°F based on separate effects tests and analysis. These cables will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program or will be re-evaluated using typical EQ techniques. ANO-1 EQ equipment using this cable is at 140°F, or below.

4.4.7.3 Wear/Cycles Considerations

Not applicable to cable.

4.4.7.4 Conclusion

The Boston insulated wire cables will be replaced prior to exceeding their qualified life or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.8 Buchanan Terminal Blocks, Outside Reactor Building

Buchanan terminal blocks are installed in various applications outside the reactor building.

4.4.8.1 Radiation Considerations

The post accident dose of $1.48x10^7$ rads plus the normal aging 60-year life dose of $5.25x10^6$ rads results in a $2.005x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.8.2 Thermal Considerations

These terminal blocks have a qualified life of 60 years at 120°F. The ANO-1 applications are at, or below, 120°F.

4.4.8.3 Wear/Cycles Considerations

Not applicable to terminal blocks.

4.4.8.4 Conclusion

Buchanan terminal blocks, outside reactor building, EQ aging analyses have been projected to the end of the period of extended operation.

4.4.9 Buchanan Terminal Blocks, Inside Reactor Building

Buchanan terminal blocks are installed in various applications inside the reactor building, typically inside Limitorque motor operated valve actuators.

4.4.9.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.04x10^8$ rads.

4.4.9.2 Thermal Considerations

These terminal blocks have a qualified life of 62 years at 120°F. The ANO-1 applications are at, or below, 120°F.

4.4.9.3 Wear/Cycles Considerations

Not applicable to terminal blocks.

4.4.9.4 Conclusion

Buchanan terminal blocks, inside reactor building, EQ aging analyses have been projected to the end of the period of extended operation.

4.4.10 Conax Thermocouples

Conax thermocouples are installed on the decay heat system to monitor decay heat return temperatures as NRC Regulatory Guide (RG) 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Category 2 variables.

4.4.10.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is much less than the qualified value of 2.27×10^8 rads.

4.4.10.2 Thermal Considerations

The EQ documentation shows that the thermocouples are qualified for 40 years at a maximum service temperature of 179°F. However, using the 1.27 eV activation energy, 300-302°F test temperatures and 470.25 hour test duration, the equivalent qualified life at 105°F service temperature, for the ANO-1 specific applications, is well in excess of 60 years.

4.4.10.3 Wear/Cycles Considerations

Not applicable to Conax thermocouples.

4.4.10.4 Conclusion

Conax thermocouples EQ aging analyses have been projected to the end of the period of extended operation.

4.4.11 Conax Resistance Temperature Detectors

Conax Resistance Temperature Detectors monitor temperatures for a RG 1.97 Category 1 variable.

4.4.11.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.2×10^8 rads.

4.4.11.2 Thermal Considerations

The EQ documentation shows that the resistance temperature detectors are qualified for 40 years at a maximum service temperature of 250°F. However, using the 3.91 eV activation energy, 302°F test temperatures and 168 hour test duration, the equivalent qualified life at 180°F service temperature, for the ANO-1 specific applications, is well in excess of 60 years.

4.4.11.3 Wear/Cycles Considerations

Not applicable to Conax Resistance Temperature Detectors.

4.4.11.4 Conclusion

Conax Resistance Temperature Detectors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.12 Conax Multipin Connector

Conax multipin connectors have been used in limited applications.

4.4.12.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.25x10^8$ rads.

4.4.12.2 Thermal Considerations

The EQ documentation shows that the connectors are qualified for 40 years at a maximum service temperature of 227°F. However, using the 3.81 eV activation energy, 276°F test temperatures and 168 hour test duration, the equivalent qualified life at 180°F service temperature, for the ANO-1 specific applications, is in excess of 60 years.

4.4.12.3 Wear/Cycles Considerations

These devices were installed in 1986 and refueling outages are once every 18 months. Assuming they are mated and unmated every refueling outage, the total number of mating and unmating operations is (2034 - 1986)/1.5 = 32 cycles. The devices were tested for 50 mating and unmating cycles. This is adequate to allow the devices to extend through the license renewal period.

4.4.12.4 Conclusion

Conax multipin connectors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.13 Conax Electrical Penetration Assemblies

ANO-1 has a total of 59 Conax electrical canister type penetrations of which, currently, 19 are spares and 40 are in use.

4.4.13.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 8.7×10^7 rads.

4.4.13.2 Thermal Considerations

The EQ documentation shows that the assemblies are qualified for 43 years at 140°F. However, using the 1.04 eV activation energy, 302°F test temperatures and 171 hour test duration, the equivalent qualified life at 120°F service temperature, for the ANO-1 applications, is in excess of 60 years.

4.4.13.3 Wear/Cycles Considerations

Not applicable to Conax Electrical Penetration Assemblies.

4.4.13.4 Conclusion

Conax Electrical Penetration Assemblies EQ aging analyses have been projected to the end of the period of extended operation.

4.4.14 Conax Electrical Connection Seal Assembly

ANO-1 utilizes Conax electrical connection seal assemblies in various applications to provide a sealed feedthrough of circuits to the end device, such as Rosemount transmitters.

4.4.14.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.28×10^8 rads.

4.4.14.2 Thermal Considerations

The EQ documentation shows that the Conax electrical connection assemblies are qualified for 60 years at 180°F. The ANO-1 applications are at, or below, 180°F.

4.4.14.3 Wear/Cycles Considerations

Not applicable to Conax Electrical Connection Seal Assembly.

4.4.14.4 Conclusion

Conax Electrical Connection Seal Assembly EQ aging analyses have been projected to the end of the period of extended operation.

4.4.15 Conax Electrical Feedthrough Adapters

ANO-1 utilizes these Conax feedthrough adapters in limited applications.

4.4.15.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.15.2 Thermal Considerations

The EQ documentation shows that the adapters are qualified for 60 years at 180°F. The ANO-1 applications are at, or below, 180°F.

4.4.15.3 Wear/Cycles Considerations

Not applicable to Conax feedthrough adapters.

4.4.15.4 Conclusion

Conax feedthrough adapters EQ aging analyses have been projected to the end of the period of extended operation.

4.4.16 Eaton Flame Retardant Ethylene Propylene Diene Monomer Insulated Cable

ANO-1 utilizes Eaton (Samuel-Moore) cable with insulation and a Hypalon jacket (Dekoron).

4.4.16.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.16.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 194°F or 60 years at 186°F. For ANO-1, EQ equipment using this cable is at 180°F, or below.

4.4.16.3 Wear/Cycles Considerations

Not applicable to Eaton cable.

4.4.16.4 Conclusion

Eaton cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.17 Gems DeLaval Level Sensors

For ANO-1, these are the reactor building sump and flood level detectors that are RG 1.97 qualified. They are located inside of the reactor building.

4.4.17.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.17.2 Thermal Considerations

The EQ documentation shows that the sensors are qualified for 40 years at 120°F. These devices are located at the bottom level of the reactor building. Actual operating temperature in this area is typically less than 90° F. Using the 0.78 eV activation energy, 120°C test temperatures and 2161.3 hour test duration, the equivalent qualified life, at a conservative 110°F service temperature, is in excess of 60 years.

4.4.17.3 Wear/Cycles Considerations

Not applicable to Gems/DeLaval level sensors.

4.4.17.4 Conclusion

Gems/DeLaval level sensors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.18 General Atomic Radiation Detectors

The reactor building high range radiation detectors that are RG 1.97 qualified. These devices are located inside of the reactor building.

4.4.18.1 Radiation Considerations

The radiation detectors have no organic materials and are not affected by radiation.

4.4.18.2 Thermal Considerations

The radiation detectors have no organic materials and are not affected by thermal aging.

4.4.18.3 Wear/Cycles Considerations

Not applicable to General Atomic radiation detectors.

4.4.18.4 Conclusion

General Atomic radiation detectors EQ aging analyses remain valid for the period of extended operation.

4.4.19 General Electric Terminal Blocks

General Electric terminal blocks have been qualified for use inside the reactor building for ANO-1, typically in Limitorque motor operated valve actuators.

4.4.19.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.59×10^8 rads.

4.4.19.2 Thermal Considerations

The EQ documentation shows that the terminal blocks are qualified for 60 years at 180°F. The ANO-1 applications are at, or below, 180°F.

4.4.19.3 Wear/Cycles Considerations

Not applicable to General Electric terminal blocks.

4.4.19.4 Conclusion

General Electric terminal blocks EQ aging analyses have been projected to the end of the period of extended operation.

4.4.20 ITT/General Controls Electro-hydraulic Actuators

These are ITT/General Controls electro-hydraulic actuators installed on the penetration room ventilation dampers located outside the reactor building.

4.4.20.1 Radiation Considerations

The post accident dose of $3.3x10^5$ rads plus the normal aging 60-year life dose of $1.32x10^3$ rads results in a $3.3132x10^5$ rads TID, which is much less than the qualified value of $2.0x10^6$ rads.

4.4.20.2 Thermal Considerations

The EQ documentation shows that the actuators are qualified for 40 years at 105°F with specific part replacements at intervals less than 40 years. These will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program. The ANO-1 applications are at, or below, 105°F.

4.4.20.3 Wear/Cycles Considerations

These ITT/General Controls electro-hydraulic actuators are cycled once a month, and over 60 years, would be exposed to 792 cycles. The devices were tested for 1250 cycles, which exceeds the required cycles with significant margin.

4.4.20.4 Conclusion

The ITT/General Controls electro-hydraulic actuator parts are scheduled to be replaced prior to exceeding their qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.21 Limitorque Motor Operated Valve Actuators; Alternating Current/Inside Reactor Building

Limitorque type SMB motor operated valve actuators with alternating current powered motors are installed inside the reactor building in various applications.

4.4.21.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.21.2 Thermal Considerations

The EQ documentation shows that the actuators are qualified for greater than 60 years at 140°F. Most applications are at, or below, 120°F. Applications at temperatures above 140°F have been evaluated separately and replacements are identified as a normal part of the ANO EQ Process.

4.4.21.3 Wear/Cycles Considerations

Most of these motor operated valves will be exposed to an expected 792 cycles over 60 years, while a few (like the sampling valves) are conservatively assumed to be cycled once a week over the 60 years (+ 10%) for a total of 3432 cycles. Limitorque motor operated valves have been tested to 4195 cycles which exceeds the required with significant margin.

4.4.21.4 Conclusion

Limitorque motor operated valves alternating current applications inside reactor building EQ aging analyses have been projected to the end of the period of extended operation for most applications while others have scheduled replacements prior to exceeding their qualified life. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.22 Limitorque Motor Operated Valve Actuators; Alternating Current/Outside Reactor Building

Limitorque type SMB motor operated valve actuators with alternating current powered motors are installed outside the reactor building in various applications.

4.4.22.1 Radiation Considerations

The highest combination of post accident dose and normal aging 60-year life dose for the areas involved is 1.37×10^7 rads TID, which is less than the qualified value of 2.0×10^7 rads.

4.4.22.2 Thermal Considerations

The EQ documentation shows that the actuators are qualified for greater than 60 years at 140°F. The ANO-1 alternating current applications outside reactor building are at, or below, 140°F.

4.4.22.3 Wear/Cycles Considerations

These Limitorque motor operated valves are cycled once a month, or less, and over 60 years would be exposed to 792 cycles. The devices were tested for at least 1993 cycles, which exceeds the required with significant margin.

4.4.22.4 Conclusion

Limitorque motor operated valves alternating current applications outside reactor building EQ aging analyses have been projected to the end of the period of extended.

4.4.23 Limitorque Motor Operated Valve Actuators; Direct Current/Outside Reactor Building

Limitorque type SMB motor operated valve actuators with direct current powered motors are installed outside the reactor building in various applications. The current EQ documentation conservatively evaluates these devices for inside reactor building applications.

4.4.23.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.23.2 Thermal Considerations

The EQ documentation shows that the actuators are qualified for greater than 60 years at 140°F. The ANO-1 applications are at, or below, 120°F.

4.4.23.3 Wear/Cycles Considerations

These Limitorque motor operated valves are cycled once a month, or less, and over 60 years would be exposed to 792 cycles. The devices were tested for 2004 cycles, which exceeds the required with significant margin.

4.4.23.4 Conclusion

Limitorque motor operated valves direct current applications outside reactor building EQ aging analyses have been projected to the end of the period of extended operation.

4.4.24 NAMCO EA-170 Limit Switches

NAMCO EA-170 Series limit switches are used to provide position indication.

4.4.24.1 Radiation Considerations

The post accident dose of 1.48×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.005×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.24.2 Thermal Considerations

These switches have a life shorter than 40 years at their service temperature of 105°F. They will be replaced prior to exceeding the established life as a normal course of the ANO EQ Program.

4.4.24.3 Wear/Cycles Considerations

The devices are qualified for 100,000 cycles, which is much greater than the 792 cycles expected over a 60-year period.

4.4.24.4 Conclusion

The NAMCO EA-170 Series limit switches are scheduled to be replaced prior to exceeding their qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.25 NAMCO EA-180 Limit Switches

NAMCO EA-180 Series limit switches are used to provide position indication.

4.4.25.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.2x10^{10}$ rads.

4.4.25.2 Thermal Considerations

These switches have a life shorter than 40 years at their service temperature of 120°F. They will be replaced prior to exceeding the established life as a normal course of the ANO EQ Program.

4.4.25.3 Wear/Cycles Considerations

The devices are qualified for 100,300 cycles, which is much greater than the 3432 cycles expected over a 60-year period.

4.4.25.4 Conclusion

The NAMCO EA-180 Series limit switches are scheduled to be replaced prior to exceeding their qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.26 NAMCO EA-740 Limit Switches with NAMCO Connectors

NAMCO EA-740 Series limit switches with NAMCO connectors are used to provide position indication. The switch and connector are qualified by the same report. The ANO-1 applications of these grouped devices are currently limited to outside the reactor building.

4.4.26.1 Radiation Considerations

The post accident dose of 1.48×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.005×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.26.2 Thermal Considerations

These switches have a life of 47.1 years at their service temperature of 105°F. The current applications were installed in 1986, therefore, a life of 48 years is needed (2034 - 1986 = 48) to extend through the renewal period. Therefore, they will be replaced prior to exceeding the established life as a normal course of the ANO EQ Program, or will be re-evaluated using typical EQ techniques such as reducing the assumed service temperature by using actual plant operating temperature data.

4.4.26.3 Wear/Cycles Considerations

The devices are qualified for 100,000 cycles, which is much greater than the 3,432 cycles expected over a 60-year period.

4.4.26.4 Conclusion

The NAMCO EA-740 Series limit switches with NAMCO connectors will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.27 NAMCO EA-740 Limit Switches

NAMCO EA-740 Series limit switches are used to provide position indication.

4.4.27.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.27.2 Thermal Considerations

The ANO-1 switches have a life of 53 years at their service temperature of 106°F. The applications were installed no earlier than December 1984 (2034 – 1984 = 50 years needed). Therefore, EQ Documentation shows that the life will extend through the renewal period.

4.4.27.3 Wear/Cycles Considerations

The devices are qualified for 100,322 cycles, which is much greater than the 792 cycles expected over a 60-year period.

4.4.27.4 Conclusion

The NAMCO EA-740 Series limit switches EQ aging analyses have been projected to the end of the period of extended operation.

4.4.28 NAMCO Quick Connectors

NAMCO connectors are used in various applications to provide a sealed feedthrough of circuits to the end device, such as Rosemount transmitters.

4.4.28.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.04×10^8 rads.

4.4.28.2 Thermal Considerations

These connectors have a life greater than 60 years at 120°F. The ANO-1 applications are at or below 120°F.

4.4.28.3 Wear/Cycles Considerations

Not applicable to NAMCO connectors.

4.4.28.4 Conclusion

The NAMCO connectors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.29 Okonite 5 kV Power Cable with EPR insulation and an Okolon jacket

ANO-1 utilizes Okonite 5 kV power cable in limited EQ applications.

4.4.29.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.29.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 60 years at 150°F. EQ equipment using this cable is at 120°F, or below.

4.4.29.3 Wear/Cycles Considerations

Not applicable to Okonite cable.

4.4.29.4 Conclusion

The Okonite 5 kV power cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.30 Okonite 2 kV Power and Control Cable with Okonite or Okoguard insulation and Okoprene or Okolon jackets

ANO-1 utilizes Okonite 2 kV Power and Control cable in various applications.

4.4.30.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.30.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 60 years at 150°F. EQ equipment using this cable is at 120°F, or below.

4.4.30.3 Wear/Cycles Considerations

Not applicable to Okonite cable.

4.4.30.4 Conclusion

The Okonite 2 kV power cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.31 Okonite 600V power cable with Okonite insulation and an Okolon jacket

ANO-1 utilizes Okonite 600V power cable with Okonite insulation and an Okolon jacket in various applications.

4.4.31.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.31.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 158°F or 60 years at 150°F. EQ equipment using this cable is at 156°F, or below. Cables currently identified at temperatures above 150°F will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program or re-evaluated using standard EQ techniques.

4.4.31.3 Wear/Cycles Considerations

Not applicable to Okonite cable.

4.4.31.4 Conclusion

For most applications of this Okonite 600V cable, the EQ aging analyses have been projected to the end of the period of extended operation. Specific applications will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.32 Okonite 600V power cable with FMR insulation

ANO-1 utilizes Okonite 600V power cable with FMR insulation in various applications.

4.4.32.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.32.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 158°F or 60 years at 150°F. Additional analyses are used to compute a life in excess of 40 years at 180°F. Most EQ equipment using this cable is at 120°F, or below. Specific applications of this cable are at an average temperature of 165°F. Cables currently identified at temperatures above 150°F will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.32.3 Wear/Cycles Considerations

Not applicable to Okonite cable.

4.4.32.4 Conclusion

For most applications of this Okonite 600V cable, the EQ aging analyses have been projected to the end of the period of extended operation. Specific applications will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.33 Okonite T-95 and No. 35 Splicing Tapes

ANO-1 utilizes Okonite tape splices made of the T-95 and No. 35 tapes in various applications.

4.4.33.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.33.2 Thermal Considerations

Thermal aging test conditions qualify the tape splices for 40 years at 165°F, or 60 years at 158°F. Additional analyses are used to establish a life of 40 years at 90°C (194°F). Most applications are at, or below, 150°F. For those above 158°F, replacement is required prior to exceeding the qualified life.

4.4.33.3 Wear/Cycles Considerations

Not applicable to Okonite tape splices.

4.4.33.4 Conclusion

The Okonite tape splice EQ aging analyses have been projected to the end of the period of extended operation, for most applications, while others have scheduled replacements prior to exceeding their qualified life. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.34 Raychem 600V Flamtrol XLPE Cable

ANO-1 utilizes Raychem 600V power, control and instrumentation cable in various applications.

4.4.34.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.34.2 Thermal Considerations

The thermal aging test conditions qualify the cable for greater than 40 years at 150°F or 60 years at 143°F. EQ equipment using this cable is at 120°F, or below.

4.4.34.3 Wear/Cycles Considerations

Not applicable to Raychem cable.

4.4.34.4 Conclusion

The Raychem cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.35 Raychem Cable Splice and Jacket Repair Tape (type NJRT)

ANO-1 utilizes Raychem cable splice and jacket repair tape (type NJRT) in limited applications.

4.4.35.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.15x10^8$ rads.

4.4.35.2 Thermal Considerations

The EQ documentation shows that the tapes are qualified for 40 years at 194°F. This is equivalent to greater than 60 years at 180 °F using standard EQ techniques. The ANO-1 applications are at, or below, 180 °F.

4.4.35.3 Wear/Cycles Considerations

Not applicable to Raychem repair tapes.

4.4.35.4 Conclusion

The Raychem repair tapes EQ aging analyses have been projected to the end of the period of extended operation.

4.4.36 Raychem Cable Splices (types WCSF-N, NPK, NMCK, ANK, etc.)

ANO-1 utilizes Raychem cable splices in various applications, mostly in instrumentation circuits.

4.4.36.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.36.2 Thermal Considerations

The EQ documentation shows that the splices are qualified for 40 years at 194°F. This is equivalent to greater than 60 years at 180 °F using standard EQ techniques. The ANO-1 applications are at, or below, 180 °F.

4.4.36.3 Wear/Cycles Considerations

Not applicable to Raychem splices.

4.4.36.4 Conclusion

The Raychem splices EQ aging analyses have been projected to the end of the period of extended operation.

4.4.37 Reliance Electric, Electric Motors

ANO-1 utilizes Reliance Electric, electric motors in limited applications. Four large motors are installed on the reactor building coolers and four other smaller motors are installed in the reactor building coolers dropout dampers.

4.4.37.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 1.0×10^9 rads.

4.4.37.2 Thermal Considerations

The EQ documentation shows that the motors are qualified for greater than 60 years at 120 °F. The ANO-1 applications are at, or below 120 °F.

4.4.37.3 Wear/Cycles Considerations

The devices are qualified for 1024 cycles, which is much greater than 704 cycles expected over a 60-year period.

4.4.37.4 Conclusion

The Reliance Electric, electric motors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.38 Rockbestos Coaxial Cable

ANO-1 utilizes Rockbestos coaxial cable in various applications.

4.4.38.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.38.2 Thermal Considerations

The thermal aging test conditions qualify the cable for 40 years at 155°F or 60 years at 150°F. Additional analyses are used to compute a life in excess of 40 years at 180°F. Most EQ equipment using this cable is at 120°F, or below. Specific applications of this cable are at 180°F, or below. Cables currently identified at temperatures above 150°F will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.38.3 Wear/Cycles Considerations

Not applicable to Rockbestos cable.

4.4.38.4 Conclusion

For most applications of this Rockbestos coaxial cable, the EQ aging analyses have been projected to the end of the period of extended operation. Specific applications will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.39 Rockbestos Firewall III Irradiation Cross-Linked Polyethylene Cable

ANO-1 utilizes Rockbestos Firewall III irradiation cross-linked polyethylene cable in various applications.

4.4.39.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.39.2 Thermal Considerations

The EQ documentation shows that the cables are qualified for 60 years at 190°F. The ANO-1 applications are at, or below, 120°F.

4.4.39.3 Wear/Cycles Considerations

Not applicable to Rockbestos cable.

4.4.39.4 Conclusion

The Rockbestos Firewall III irradiation cross-linked polyethylene cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.40 Rockbestos Firezone R Silicone Rubber High Temperature Cable

ANO-1 utilizes Rockbestos Firezone R silicone rubber high temperature cable in limited applications.

4.4.40.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID. This cable was tested to $5.0x10^7$ rads and additional analysis shows it can withstand up to $1.5x10^8$ rads.

4.4.40.2 Thermal Considerations

The EQ documentation shows that the cables are qualified for 40 years at 181°F, or 60 years at 176°F. The ANO-1 applications are at, or below, 180°F. Cables currently identified at temperatures above 176°F will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.40.3 Wear/Cycles Considerations

Not applicable to Rockbestos cable.

4.4.40.4 Conclusion

For some applications of this Rockbestos Firezone R silicone rubber high-temperature cable, the EQ aging analyses have been projected to the end of the period of extended operation. Other applications will be replaced prior to exceeding their qualified life or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.41 Rockbestos Firewall III Chemically Cross-Linked Polyethylene Cable

ANO-1 utilizes Rockbestos Firewall III chemically cross-linked polyethylene cable in various applications.

4.4.41.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.41.2 Thermal Considerations

The EQ documentation shows that the cables are qualified for 60 years at 190°F. The ANO-1 applications are at, or below, 120°F.

4.4.41.3 Wear/Cycles Considerations

Not applicable to Rockbestos cable.

4.4.41.4 Conclusion

The Rockbestos Firewall III chemically cross-linked polyethylene cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.42 Rosemount Model 1153 Series D Pressure Transmitters

Rosemount Model 1153 Series D pressure transmitters are used in various applications.

4.4.42.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID. Output code R transmitters (improved radiation performance) are qualified for $1.1x10^8$ rads and standard transmitters are qualified for $5.2x10^7$ rads. The transmitters inside the reactor building are Type R, which are qualified for the high radiation. The radiation outside the reactor building is lower than the qualification of the standard transmitters, therefore, they are qualified.

4.4.42.2 Thermal Considerations

The transmitter, circuit boards, and O-rings are already identified in the ANO EQ Program as requiring replacement at specific intervals based on the service temperature of the specific transmitter.

4.4.42.3 Wear/Cycles Considerations

Not applicable to Rosemount transmitters.

4.4.42.4 Conclusion

The ANO EQ Program requires replacements prior to exceeding the qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.43 Rosemount Model 1154 Pressure Transmitters

Rosemount model 1154 pressure transmitters are used in various applications.

4.4.43.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 1.1×10^8 rads.

4.4.43.2 Thermal Considerations

The transmitter, circuit boards, and O-rings are already identified in the ANO EQ Program as requiring replacement at specific intervals based on the service temperature of the specific transmitter.

4.4.43.3 Wear/Cycles Considerations

Not applicable to Rosemount transmitters.

4.4.43.4 Conclusion

The ANO EQ Program requires replacements prior to exceeding the qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.44 Rotork Motor Operated Valve Actuators, Model NA1

Rotork motor operated valve actuators are used in specific applications.

4.4.44.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is less than the minimum qualified value of $6.0x10^7$ rads.

4.4.44.2 Thermal Considerations

The EQ documentation shows that the actuators are qualified for greater than 60 years at 120°F. The ANO-1 applications are at, or below, 120°F.

4.4.44.3 Wear/Cycles Considerations

The devices are qualified for 2,000 cycles, which is greater than the 792 cycles expected over a 60-year period.

4.4.44.4 Conclusion

The Rotork motor operated valve actuators EQ aging analyses have been projected to the end of the period of extended operation.

4.4.45 Target Rock Solenoid Operated Valves (Report 2375)

Target Rock solenoid operated valves are used in various applications.

4.4.45.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $1.35x10^8$ rads.

4.4.45.2 Thermal Considerations

The EQ documentation shows that the valves are qualified for greater than 60 years at 180°F. The ANO-1 applications are at, or below, 180°F.

4.4.45.3 Wear/Cycles Considerations

The devices are qualified for 18,000 cycles, which is greater than the conservatively assumed one cycle per week (+ 10%), or a total of 3,432 cycles expected over a 60-year period.

4.4.45.4 Conclusion

The Target Rock solenoid operated valves EQ aging analyses have been projected to the end of the period of extended operation.

4.4.46 Target Rock Solenoid Operated Valves (Reports 2375 and 3996)

Target Rock solenoid operated valves are used in specific applications.

4.4.46.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 1.35×10^8 rads.

4.4.46.2 Thermal Considerations

The solenoid operated valves are already identified in the ANO EQ Program as requiring replacement at specific intervals based on the service temperature of the specific valve.

4.4.46.3 Wear/Cycles Considerations

The devices are qualified for 18,000 cycles, which is greater than the conservatively assumed one cycle per week (+ 10%), or total of 3,432 cycles, expected over a 60-year period.

4.4.46.4 Conclusion

The ANO EQ Program requires replacements prior to exceeding the qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.47 Target Rock Modulating Solenoid Operated Valves (Report 3414)

Target Rock modulating solenoid operated valves are used in only one EQ application, emergency feedwater flow control. The valve was installed in 1984 and needs a 50 to 51-year life (2034 - 1984 = 50 years) for the period of extended operation.

4.4.47.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is less than the qualified value of 7.07×10^7 rads.

4.4.47.2 Thermal Considerations

The EQ documentation shows that the valves are qualified for 53 years at 105°F. The ANO-1 application is outside reactor building and is at or below 105°F.

4.4.47.3 Wear/Cycles Considerations

The devices are qualified for 2,000 full cycles and 99,565 partial cycles, which is greater than the 1,144 cycles expected over a 60-year period.

4.4.47.4 Conclusion

The Target Rock solenoid operated valve EQ aging analyses have been projected to the end of the period of extended operation.

4.4.48 Target Rock Solenoid Operated Valves (Reports 2375 and 1827)

Target Rock solenoid operated valves are used in specific applications.

4.4.48.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 1.35×10^8 rads.

4.4.48.2 Thermal Considerations

The EQ documentation shows that the valves are qualified for greater than 60 years at 120°F. The ANO-1 applications are at, or below, 120°F.

4.4.48.3 Wear/Cycles Considerations

The devices are qualified for 18,000 cycles, which is greater than the conservatively assumed one cycle per week (+ 10%), or total of 3,432 cycles expected over a 60-year period.

4.4.48.4 Conclusion

The Target Rock solenoid operated valve EQ aging analyses have been projected to the end of the period of extended operation.

4.4.49 TEC Valve Flow Monitoring System

These are the pressurizer safety valve and PORV flow monitoring system, which consists of accelerometers, hardline cable, cable couplers, pre-amplifiers, and transient shields.

4.4.49.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.02x10^8$ rads.

4.4.49.2 Thermal Considerations

The EQ documentation supports qualified lives greater than 60 years at 180°F for several subcomponents. Other subcomponents have a qualified life of less than 40 years and will be replaced as a normal course of the ANO EQ Program or re-evaluated using standard EQ techniques. One subcomponent has been determined to be qualified for 49 years at 160°F and will be replaced prior to exceeding the life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.49.3 Wear/Cycles Considerations

Not applicable to the valve flow monitoring system.

4.4.49.4 Conclusion

For some subcomponents, the EQ aging analyses have been projected to the end of the period of extended operation. Others will be replaced prior to exceeding their qualified life or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.50 TEC Reactor Vessel Level Monitoring System

The reactor vessel level monitoring systems, consists of level sensors, cable, cable connectors, and splices.

4.4.50.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $1.1x10^8$ rads. The qualified life of the TEC Model 125 RLI probe is 35 years, based on the expected neutron flux inside of the reactor.

4.4.50.2 Thermal Considerations

The EQ documentation shows that most of the subcomponents are qualified for 40 years or less and are currently identified as requiring replacement as a normal course of the ANO EQ Program. Other subcomponents have a qualified life of greater than 60 years at their associated service temperature.

4.4.50.3 Wear/Cycles Considerations

The connectors have been qualified for 160 cycles which is greater than the 40 cycles expected over a 60 year period.

4.4.50.4 Conclusion

For some subcomponents, the EQ aging analyses have been projected to the end of the period of extended operation. Most subcomponents will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.51 Weed Resistance Temperature Detectors

Several Weed Resistance Temperature Detectors that are installed as a part of the reactor cooling system hot legs level monitoring system as a RG 1.97 Category 1 variable.

4.4.51.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 3.03×10^8 rads.

4.4.51.2 Thermal Considerations

The ANO-1 applications have a life of 55.5 years at 180°F for 4 years and 155°F for the remainder and were installed in 1986 (2034 – 1986 = 48 years needed). Therefore, the EQ Documentation indicates the life will extend through the renewal period.

4.4.51.3 Wear/Cycles Considerations

Not applicable to resistance temperature detectors.

4.4.51.4 Conclusion

The Weed resistance temperature detectors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.52 Dow-Corning 3145 Silicone Sealant

Dow-Corning silicone sealant is used in various applications.

4.4.52.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.2×10^8 rads.

4.4.52.2 Thermal Considerations

The EQ documentation shows that this sealant is qualified for greater than 60 years at 180°F. The ANO-1 applications are at or below 180°F.

4.4.52.3 Wear/Cycles Considerations

Not applicable to this silicone sealant.

4.4.52.4 Conclusion

The Dow-Corning silicone sealant EQ aging analyses have been projected to the end of the period of extended operation.

4.4.53 Westinghouse Hydrogen Recombiners

Two hydrogen recombiners were added to the ANO-1 reactor building in 1986. These recombiners are primarily constructed of metallic materials, metal enclosed thermal insulation and metal clad ceramic insulated heater elements, which are considered non-age sensitive materials. The age sensitive materials are the Boston Insulated Wire heater power cable and the Firezone 101 heater connection cable. Based on information from Westinghouse, the Firezone 101 is not age or radiation sensitive except for the Teflon finisher, which is not required for the cable to perform its safety function.

4.4.53.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.53.2 Thermal Considerations

The EQ documentation indicates the Boston Insulated Wire cable is qualified in this application for 44.4 years at 156°F for 5 years and 120°F for the remainder. This will not be enough life to allow it to extend through the license renewal period. This cable will be replaced prior to exceeding the qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.53.3 Wear/Cycles Considerations

Not applicable to the hydrogen recombiners.

4.4.53.4 Conclusion

The Boston Insulated Wire cable to the recombiners will be replaced prior to exceeding the qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.54 Westinghouse Motors, Model ABDP

Seven pumps utilize Westinghouse motors in the decay heat, reactor building spray, and makeup/HPI systems, which are located outside the reactor building.

4.4.54.1 Radiation Considerations

The post accident dose of 1.48×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.005×10^7 rads TID, which is much less than the qualified value of 1.4×10^8 rads.

4.4.54.2 Thermal Considerations

The EQ documentation shows that the Westinghouse motors are qualified in these applications for 40 years at 105°F. These motors will be replaced prior to exceeding the qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.54.3 Wear/Cycles Considerations

The motors are qualified for 1,000 cycles, which is more than the 792 cycles expected over a 60-year period.

4.4.54.4 Conclusion

These Westinghouse motors will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.55 Westinghouse Motors, Models TBFC and SBDP

Applications of these motors are the penetration room ventilation fan motors, located outside reactor building.

4.4.55.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is much less than the qualified value of 1.4×10^8 rads.

4.4.55.2 Thermal Considerations

The EQ documentation shows that these Westinghouse motors are qualified for 78,840 hours of operation at their maximum operating temperature of 120°C. During plant operation, the motors do not run (i.e., only run during surveillances). The surveillances would, conservatively, run the motors 160 hours every 18 months, which would equal 6,400 hours in 60 years. Add a conservative 1-year post-accident operating time (8,760 hours) and a conservative total run-time would be 15,160 hours. This is significantly less than the 78,840 hours for which the motor is qualified and would conservatively allow it to extend through the license renewal period.

4.4.55.3 Wear/Cycles Considerations

The motors are qualified for 1,000 cycles, which is more than the 880 cycles expected over a 60-year period.

4.4.55.4 Conclusion

These Westinghouse motor EQ aging analyses have been projected to the end of the period of extended operation.

4.4.56 Babcock & Wilcox Core Exit Thermocouples

These are the 24 incore detectors with thermocouples that are RG 1.97 qualified.

4.4.56.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.07×10^8 rads.

4.4.56.2 Thermal Considerations

The EQ documentation shows that some subcomponents of these devices have a qualified life of less than 40 years. The thermocouple, detector probe, socket connector, and O-ring have qualified lives less than 40 years at its service temperature of 120°F. The pin half connector with the mineral-insulated cable is qualified for greater than 60 years at their service temperature of 120^0 F. Therefore, the EQ program already identifies the necessary replacements that support plant operation in the license renewal period.

4.4.56.3 Wear/Cycles Considerations

The connectors are qualified for 50 mating/unmatings. These are unmated and pulled each refueling outage (i.e. once every 18 months over 60 years or 40 times).

4.4.56.4 Conclusion

For the pin half connector with the mineral-insulated cable, the EQ aging analyses have been projected to the end of the period of extended operation. Other subcomponents will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.57 Gamma Metrics Neutron Detectors and Cable Assemblies

Two Gamma Metrics excore neutron detectors and cable assemblies that were installed in 1984 and are RG 1.97 qualified. The detector assemblies (detector and mineral-insulated cable) are located in wells in the concrete biological shield wall next to the reactor vessel. The cable assemblies (organic connecting cables) and junction boxes are located outside the D-ring walls in the general areas of the reactor building.

4.4.57.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $3.2x10^9$ rads (detector assembly and cable assemblies) and $6.0x10^7$ (junction box o-ring). Given their location, these detectors are also exposed to neutron radiation. The current ANO EQ documentation shows that the detector assemblies have a qualified life of just over 40 years, based on the expected 40-year neutron flux dose of $2.762x10^9$ rads to the detector assembly. These will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. The cable assemblies and junction boxes are qualified for 60 years.

4.4.57.2 Thermal Considerations

The EQ documentation shows that the detector assemblies and junction box O-ring have a qualified life of 40 years at their service temperature of 120°F. These will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques. Mineral-insulated cable extending from the detector is non-age sensitive. The organic cable is qualified for 50 years at 180°F while the application is at, or below 120°F. This 50 year life is enough to extend through the renewal period, given the installation date of the system.

4.4.57.3 Wear/Cycles Considerations

Not applicable to the Gamma Metrics components.

4.4.57.4 Conclusion

For the organic cable, the EQ aging analyses have been projected to the end of the period of extended operation. Other subcomponents will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.58 Brand Rex Cross-Linked Polyethylene Coaxial Cable

Brand Rex cross-linked polyethylene coaxial cable is used in various applications.

4.4.58.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.58.2 Thermal Considerations

The EQ documentation indicates that this cable is qualified for 60 years at 150°F. The ANO-1 applications are at, or below, 120°F.

4.4.58.3 Wear/Cycles Considerations

Not applicable to Brand Rex cable.

4.4.58.4 Conclusion

The Brand Rex cross-linked polyethylene coaxial cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.59 Brand Rex Cross-Linked Polyethylene Power and Control Cable

Brand Rex cross-linked polyethylene power and control cable is used in various applications.

4.4.59.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.59.2 Thermal Considerations

The EQ documentation shows that this cable is qualified for 60 years at 150°F. The ANO-1 applications are at, or below, 120°F.

4.4.59.3 Wear/Cycles Considerations

Not applicable to Brand Rex cable.

4.4.59.4 Conclusion

The Brand Rex cross-linked polyethylene power and control cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.60 NDT International Acoustic Sensor, Connector and Cable

These are the 16 main steam safety valve position indicators that were added to the main steam safety valves as RG1.97 Category 2 variables.

4.4.60.1 Radiation Considerations

The post accident dose of $4.0\text{x}10^7$ rads plus the normal aging 60-year life dose of $1.5\text{x}10^7$ rads results in a $5.5\text{x}10^7$ rads TID, which is much less than the qualified value of $2.0\text{x}10^8$ rads.

4.4.60.2 Thermal Considerations

The EQ documentation shows that these devices are qualified for greater than 60 years at their maximum service temperature of 180°F.

4.4.60.3 Wear/Cycles Considerations

Not applicable to the sensors, connectors, and cable.

4.4.60.4 Conclusion

The NDT International acoustic sensor, connector and cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.61 American Insulated Wire 600V Instrumentation Cable

American Insulated Wire 600V cross-linked polyethylene insulation, Hypalon jacket, instrumentation cable is used in various applications.

4.4.61.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 1.0×10^8 rads.

4.4.61.2 Thermal Considerations

The EQ documentation shows that this cable is qualified for 60 years at 125°F. The ANO-1 applications are at, or below, 120°F.

4.4.61.3 Wear/Cycles Considerations

Not applicable to American Insulated Wire cable.

4.4.61.4 Conclusion

The American Insulated Wire 600V cross-linked polyethylene insulation, Hypalon jacket, instrumentation cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.62 American Insulated Wire 600V Power and Control Cable

American Insulated Wire 600V EPR insulation, Hypalon jacket, power, and control cable is used in various applications.

4.4.62.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.06×10^8 rads.

4.4.62.2 Thermal Considerations

The EQ documentation shows that this cable is qualified for 60 years at 123°F. The ANO-1 applications are at, or below, 120°F.

4.4.62.3 Wear/Cycles Considerations

Not applicable to American Insulated Wire cable.

4.4.62.4 Conclusion

The American Insulated Wire 600V EPR insulation, Hypalon jacket, power, and control cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.63 AMP Pre-insulated Butt Splices

AMP pre-insulated butt splices are limited to outside reactor building in harsh radiation only applications.

4.4.63.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is much less than the qualified value of 2.59×10^8 rads.

4.4.63.2 Thermal Considerations

The EQ documentation shows that these are qualified for 40 years at 194°F. This is equivalent to much greater than 60 years at 105°F using standard EQ techniques. The ANO-1 applications are at, or below, 105°F.

4.4.63.3 Wear/Cycles Considerations

Not applicable to AMP butt splices.

4.4.63.4 Conclusion

The AMP pre-insulated butt splices EQ aging analyses have been projected to the end of the period of extended operation.

4.4.64 EGS Quick Disconnect Electrical Connectors

EGS quick disconnect electrical connectors are used in various applications.

4.4.64.1 Radiation Considerations

The post accident dose of $4.0x10^7$ rads plus the normal aging 60-year life dose of $1.5x10^7$ rads results in a $5.5x10^7$ rads TID, which is much less than the qualified value of $2.0x10^8$ rads.

4.4.64.2 Thermal Considerations

The EQ documentation shows that the connectors are qualified for 40 years at 150°F. This is equivalent to much greater than 60 years at 120°F using standard EQ techniques. Most ANO-1 applications are at, or below, 120°F. Two applications are at, or below 150°F but were installed in 1995 (2034-1995=39) so only 39 years of life are needed through the renewal period. The connector o-ring is only qualified for 10 years at 150 ^{0}F. The EQ Documentation for the specific applications using these devices identifies this replacement as a normal course of the ANO EQ Program.

4.4.64.3 Wear/Cycles Considerations

The devices are qualified for 160 disconnect/connect cycles, which is greater than the conservative 60 expected cycles (once every year).

4.4.64.4 Conclusion

The EGS quick disconnect electrical connectors EQ aging analyses have been projected to the end of the period of extended operation. The connector o-rings will be replaced prior to exceeding their qualified life, or re-evaluated using standard EQ techniques. Therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.65 EGS Grayboot Electrical Connectors

EGS Grayboot electrical connectors are used in various applications.

4.4.65.1 Radiation Considerations

The post accident dose of 4.0×10^7 rads plus the normal aging 60-year life dose of 1.5×10^7 rads results in a 5.5×10^7 rads TID, which is much less than the qualified value of 2.08×10^8 rads.

4.4.65.2 Thermal Considerations

The EQ documentation shows that the connectors are qualified for 47.4 years at 130°F. This is equivalent to greater than 60 years at 120°F using standard EQ techniques and the ANO-1 applications are at, or below, 120°F.

4.4.65.3 Wear/Cycles Considerations

The devices are qualified for 160 disconnect/connect cycles, which is greater than the conservative 60 expected cycles (once every year).

4.4.65.4 Conclusion

The EGS Grayboot electrical connectors EQ aging analyses have been projected to the end of the period of extended operation.

4.4.66 Valcor Model V526-5683 Solenoid Operated Valve

Only one Valcor solenoid valve of this model is installed outside the reactor building, in the post-accident sampling system.

4.4.66.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is much less than the qualified value of 5.9×10^7 rads.

4.4.66.2 Thermal Considerations

The EQ documentation identifies the subcomponents of this valve (solenoid assembly, valve seat, coil housing O-rings, and bracket assembly) as being qualified for less than 40 years at a 120^0F ambient. These will be replaced prior to exceeding their qualified life as a normal course of the ANO EQ Program, or re-evaluated using standard EQ techniques.

4.4.66.3 Wear/Cycles Considerations

The devices are qualified for 60,000 cycles, which is greater than the 792 cycles expected over a 60-year period.

4.4.66.4 Conclusion

The ANO EQ Program requires replacements prior to exceeding the qualified life; therefore, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.67 Valcor Model V526-5961-1 Solenoid Operated Valve

Valcor solenoid valves are installed in a limited number of applications, outside the reactor building.

4.4.67.1 Radiation Considerations

The post accident dose of 1.49×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 2.015×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.67.2 Thermal Considerations

The EQ documentation shows that the valves are qualified for 40 years at 120°F. This is equivalent to greater than 60 years at 105°F using standard EQ techniques and the ANO-1 applications are at, or below, 105°F.

4.4.67.3 Wear/Cycles Considerations

The devices are qualified for 57,500 cycles, which is greater than the 792 cycles expected over a 60-year period.

4.4.67.4 Conclusion

The Valcor model V526-5961-1 solenoid operated valve EQ aging analyses have been projected to the end of the period of extended operation.

4.4.68 General Cable Corporation 5 kV Power Cable

General Cable Corporation 5 kV power cable is used in limited applications outside the reactor building such as decay heat, high pressure injection, and reactor building spray pump motors.

4.4.68.1 Radiation Considerations

The post accident dose of 1.02×10^7 rads plus the normal aging 60-year life dose of 5.25×10^6 rads results in a 1.545×10^7 rads TID, which is much less than the qualified value of 2.0×10^8 rads.

4.4.68.2 Thermal Considerations

The EQ documentation shows that this cable is qualified for 60 years at 145 °F. The ANO-1 applications are at, or below, 120°F.

4.4.68.3 Wear/Cycles Considerations

Not applicable to cable.

4.4.68.4 Conclusion

The General Cable Corporation 5 kV power cable EQ aging analyses have been projected to the end of the period of extended operation.

4.4.69 GSI-168 "EQ of Electrical Components"

As discussed in SECY-93-049, the staff reviewed significant license renewal issues and found that several were related to environmental qualification. An essential aspect of these issues was whether the licensing basis should be reassessed or enhanced in connection with license renewal, and whether this reassessment should be extended to the current license term. In late 1993, the Commissioners instructed the Staff that the current EQ licensing basis must be used in the license renewal period and that any EQ concerns identified by the staff during the review of EQ for license renewal should be evaluated for the effect on current licenses, independent of license renewal.

The NRC Staff's EQ Task Action Plan was initiated to address the adequacy of current EQ practices. Upon completion of the EQ-TAP review, the focus of Staff concerns was limited to issues related to the adequacy of accelerated aging practices in existing qualifications, and the lack of a "feedback mechanism" in EQ programs (i.e., programmatic requirements to determine the current condition of EQ equipment so that it can be evaluated against the assumptions and parameters for qualification). The EQ-TAP was subsequently closed and the remaining open issues were incorporated into GSI-168 for management tracking purposes. The EQ-TAP review did not identify any generic safety issues related to these open issues. NRC research on these topics is in progress. NRC guidance for addressing GSI-168 for license renewal is contained in a June 1998 letter to NEI (Reference 4.4-2). In this letter, the NRC states:

"With respect to addressing GSI-168 for license renewal, until completion of an ongoing research program and staff evaluations, the potential issues associated with GSI-168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the SOC is to provide a technical rationale demonstrating that the current licensing basis for EQ pursuant to 10CFR50.49 will be maintained in the period of extended operation. Although the SOC also indicates that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time."

Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for ANO. The evaluations of these time-limited aging analyses are considered the technical rationale that the current licensing basis will be maintained during the period of extended operation. These evaluations are provided in this section of the ANO-1 LRA. Consistent with the above NRC guidance, no additional information is required to address GSI-168 in a renewal application at this time.

4.4.70 References for Section 4.4

4.4-1 IEEE Std 323-1974, "*Qualifying Class 1E Equipment for Nuclear Power Generating Stations*," The Institute of Electrical and Electronics Engineers, Inc., 1974.

4.4-2 C. I. Grimes (NRC) letter to D. Walters (NEI), *"Guidance on Addressing GSI 168 for License Renewal*," Project 690, dated June 2, 1998.

4.5 CONCRETE REACTOR BUILDING TENDON PRESTRESS

Loss of prestress in the post-tensioning system is due to material strain occurring under constant stress.

In accordance with ACI 318-63 (Reference 4.5-1), the design of the ANO-1 reactor building post-tensioning system provides for prestress losses caused by the following.

- Seating anchorage
- Elastic shortening of concrete
- Creep of concrete
- Shrinkage of concrete
- Relaxation of prestressing steel stress
- Frictional loss due to curvature in the tendons and contact with tendon conduit

By assuming an appropriate initial stress from tensile loading, and using appropriate prestress loss parameters, the magnitude of the design losses and the final effective prestress at the end of 40 years for typical dome, vertical, and hoop tendons was calculated at the time of initial licensing. This analysis, summarized in SAR Section 5.2.4.2.1, is a time-limited aging analysis requiring review for license renewal.

ASME Code Section XI, Subsection IWL, provides requirements for inservice inspection and repair and replacement activities of the post-tensioning systems of concrete reactor buildings. Subsection IWL requires visual examination of tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, wedges, buttonheads, shims, and the adjacent concrete. Tendon force and elongation is required to be measured to evaluate the prestress force of the system. In addition, tendon wires or strand samples are required to be removed and tested to determine the yield strength, ultimate tensile strength and elongation.

ANO-1 is completing a calculation of the final effective tendon prestress based on additional information on concrete creep from existing creep tests and results of the tendon surveillance testing. This calculation will confirm projections on tendon relaxation that show the ANO-1 reactor building tendon elements will be acceptable for the period of extended operation. In addition, the ASME Section XI Inservice Inspection Program, IWL inspections will be adequate to manage the effects of aging on the intended function for the period of extended operation. Implementation of this program dispositions this time-limited aging analysis in accordance with 10CFR54.21(c)(1)(iii).

4.5.1 References for Section 4.5

4.5-1 ACI 318-63, "*Building Code Requirements for Reinforced Concrete,*" American Concrete Institute.

4.6 Reactor Building Liner Plate Fatigue Analysis

The interior surface of the reactor building is lined with welded carbon steel plate to provide an essentially leak tight barrier. At the penetrations, the reactor building liner plate is thickened to reduce stress concentrations. Design criteria are applied to the liner plate to assure that the specified leak rate is not exceeded under design basis accident conditions. The following fatigue conditions, as described in SAR Section 5.2.1.4.7.3, were considered in the design of the liner plate:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 cycles for the plant life of 40 years.
2. Thermal cycling due to reactor building interior temperature varying during the startup and shutdown of the reactor coolant system. The number of cycles that is assumed for this loading condition is 500.
3. One thermal cycle is assumed due to DBA conditions .

The design analysis for the liner plate, which considers these fatigue conditions, is considered to be a time-limited aging analysis for the purposes of license renewal.

Each of the above fatigue conditions have been evaluated for continued operation for up to 60 years. For item (1), an increase in the number of thermal cycles due to annual outdoor temperature variations from 40 to 60 cycles is considered to be insignificant in comparison to the assumed 500 thermal cycles due to the reactor building interior temperature varying during heatup and cooldown of the reactor coolant system.

For item (2), ANO-1 operating experience indicates that the assumed 500 thermal cycles due to startup and shutdown of the reactor coolant system, is conservative. The projected number of thermal cycles for 60 years of operation, has been determined to be less than the original design 500 cycle design assumptions.

For item (3), the assumed value for thermal cycles due to DBA conditions remains valid. None have occurred and none are expected to occur.

Integrated leak rate tests are additional sources of load changes. These loads are considered within the set of design loads whose cumulative total was assumed to be 500 cycles. Due to the limited number of these tests, these additional load cycles on the liner plate are bounded by the 500 cycle assumption.

Finally, the design of the reactor building penetrations has been reviewed. The design meets the general requirements of ASME Section III for thermal cycling. By design, thermal load cycles in the piping systems are isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate.

The high temperature lines penetrating the reactor building wall and liner plate are the feedwater and main steam lines. The design number of thermal load cycles in these two systems is greater than the design number of heatup and cooldown cycles of the reactor coolant system. The projected number of cycles for ANO-1 through 60 years of operation has been determined to be less than the original design assumptions.

In summary, the assumed fatigue conditions used in the reactor building liner plate fatigue analysis are bounding for 60 years of plant operation. Therefore, this time-limited aging analysis remains valid for the period of extended operation and meets the criteria of CFR54.21(c)(1)(i).

4.6.1 References for Section 4.6

4.6-1 ASME Boiler and Pressure Vessel Code, Section III, *"Rules for Construction of Nuclear Power Plant Components,"* American Society of Mechanical Engineers.

4.7 AGING OF BORAFLEX IN SPENT FUEL POOL RACKS

Boraflex is a boron carbide dispersion in an elastomeric silicone that is currently used in a portion (Region I) of the ANO-1 spent fuel storage racks as a neutron absorber. The Region II section of the spent fuel storage racks does not contain Boraflex. Potential stressors for the Boraflex in the pool include the chemical environment of borated water and gamma radiation, which changes the material characteristics of the base polymer. NRC Information Notices 87-43, "Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks," 93-70, "Degradation of Boraflex Neutron Absorber Coupons," and 95-38, "Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks," identified the concern of aging of Boraflex neutron absorbing material. This concern resulted in NRC Generic Letter 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks."

In the ANO response to Generic Letter 96-04 [0CAN109605 (Reference 4.7-1)], Entergy Operations committed to continue monitoring and analysis of the Boraflex degradation at ANO-1. In order to ensure that the 5 percent subcriticality margin can be maintained for the life of the spent fuel storage racks, Entergy Operations will continue the existing coupon monitoring program as required into the extended license period. Entergy Operations will also continue to monitor spent fuel pool silica levels and perform silica evaluations. These evaluations are based on the EPRI RACKLIFE system or its equivalent. Projected Boraflex performance will be assessed to confirm the 5 percent subcriticality margin will be maintained as required.

Degradation of Boraflex is treated as a time-limited aging analysis at ANO-1 since this analysis meets the six criteria of 10CFR54.3. The analysis meets 10CFR54.21(c)(1)(ii) and the sampling actions meet 10CFR54.21(c)(1)(iii). Therefore, this time limited aging analysis is valid for the period of extended operation.

4.7.1 References for Section 4.7

4.7-1 0CAN109605, Letter from D. Mims (ANO) to the NRC, "*120 Day Response to Generic Letter 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks,*" dated October 24, 1996.

4.8 OTHER TIME-LIMITED AGING ANALYSES

4.8.1 Reactor Vessel Underclad Cracking

Intergranular separations (underclad cracking) in low alloy steel heat-affected zones under austenitic stainless steel weld cladding were detected in SA-508, Class-2 reactor vessel forgings manufactured to a coarse grain practice and clad by high-heat-input submerged arc processes. BAW-10013 (Reference 4.8-1) contains a fracture mechanics analysis that demonstrates the critical crack size required to initiate fast fracture is several orders of magnitude greater than the assumed maximum flaw size plus predicted flaw growth due to design fatigue cycles. The flaw growth analysis was performed for a 40-year cyclic loading, and an end-of-life assessment of radiation embrittlement (i.e., fluence at 32 EFPY) was used to determine fracture toughness properties. The report concluded that the intergranular separation found in B&W vessels would not lead to vessel failure. This conclusion was accepted by the AEC. To cover the period of extended operation, an analysis was performed using current ASME Code (Reference 4.8-2) requirements. This analysis is fully described in Appendix C of BAW-2251A (Reference 4.8-3).

In May 1973, the AEC issued Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components." The guide states that underclad cracking "... has been reported only in forgings and plate material of SA-508 Class-2 composition made to coarse grain practice when clad using high-deposition-rate welding processes identified as 'high-heat-input' processes such as the submerged-arc wide-strip and the submerged-arc six-wire processes. Cracking was not observed in clad SA-508 Class-2 materials clad by 'low-heat-input' processes controlled to minimize heating of the base metal. Further, cracking was not observed in clad SA-533 Grade B Class-1 plate material, which is produced to fine grain practice. Characteristically, the cracking occurs only in the grain-coarsened region of the base-metal heat-affected zone at the weld bead overlap." The guide also notes that the maximum observed dimensions of these subsurface cracks is 0.165-inch deep by 0.5-inch long.

The BAW-10013 fracture mechanics analysis is a flaw evaluation performed before the ASME Code requirements for flaw evaluation, the K_{Ia} curve for ferritic steels as indexed against RT_{NDT}, and the ASME Code fatigue crack growth curves for carbon and low alloy ferritic steels were available. The revised analysis uses current fracture toughness information, applied stress intensity factor solutions, and fatigue crack growth correlations for SA-508 Class-2 material. The objective of the analysis is to determine the acceptability of the postulated flaws for 48 EFPY using ASME Code, Section XI (Reference 4.8-4), (1995 Edition), IWB-3612 acceptance criteria.

The revised analysis was applied to three relevant regions of the reactor vessel: the beltline, the nozzle belt, and the closure head/head flange. The analysis conservatively considered 360 cycles of 100°F/hr normal heatup and cooldown transients. For the power maneuvering transients, the range in applied stress intensity factors for the closure head region was assumed the same as that determined for the beltline region. This assumption is considered conservative since the closure head region is subject to a low flow condition while the beltline region is subject to a forced flow condition.

An initial flaw size of 0.353-inch deep by 2.12-inch long (6:1 aspect ratio) was conservatively assumed for each of the three regions. The flaw was further assumed to be an axially oriented, semi-elliptical surface flaw in contrast to the observed flaws which are subsurface with a maximum size of 0.165-inch deep by 0.5-inch long.

The maximum crack growth and applied stress intensity factor for the normal and upset conditions were found to occur in the nozzle belt region. The maximum crack growth considering all the normal and upset condition transients for 48 EFPY, was determined to be 0.180-inch, which results in a final flaw depth of 0.533-inch. The maximum applied stress intensity factor for the normal and upset condition results in a fracture toughness margin of 3.6 which is greater than the IWB-3612 acceptance criteria of 3.16.

The maximum applied stress intensity factor for the emergency and faulted conditions occurs in the closure head to head flange region and the fracture toughness margin was determined to be 2.24, which is greater than the IWB-3612 acceptance criterion of 1.41. It is therefore concluded that the postulated intergranular separations in the ANO-1 reactor vessel 508 Class-2 forgings are acceptable for continued safe operation through the period of extended operation. Therefore, this time limited aging analysis is acceptable per 10CFR 54.21(c)(1)(ii).

4.8.2 Reactor Vessel Incore Instrumentation Nozzles- Flow Induced Vibration Endurance Limit

ANO identified one additional time-limited aging analysis associated with the reactor vessel that was not specifically identified in the Reactor Vessel GLRP report BAW-2251A. Report BAW-10051, "Flow Induced Vibration Endurance Limit Assumptions" (Reference 4.8-7) is an analysis that calculated stress values for the reactor vessel incore nozzles and compared them to endurance limit (stress) values. These endurance limit values were based on an assumed value of 10^{12} cycles for 40 years of operation. The number of fatigue cycles was extended for 60 years, and the component item stress values were compared to the recalculated endurance limit values and shown to be acceptable. Therefore, this time limited aging analysis is acceptable per 10CFR54.21(c)(1)(ii).

4.8.3 Leak Before Break

The successful application of leak-before-break to the ANO-1 RCS main coolant piping is described in the BWOG Topical Report entitled, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS," BAW-1847, Revision 1, September 1985 (Reference 4.8-5). This report provides the technical basis for evaluating postulated flaw growth in the main RCS piping under normal plus faulted loading conditions and was approved by the NRC for the current term of operation. The time-limited aging analyses in BAW-1847, Revision 1, include fatigue flaw growth and the qualitative assessment of thermal aging of cast austenitic stainless steel reactor coolant inlet and exit nozzles.

<u>Fatigue Flaw Growth</u>

The leak-before-break analysis reported in BAW-1847, Revision 1, was performed in accordance with the guidance provided in Section 5.2, Item (d), of NUREG 1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks." Specifically, a surface flaw was postulated at selected locations of the piping system (i.e., highest stress coincident with the lower bound of the material properties for base metal, weldments and safe ends), and a fatigue crack growth analysis for postulated flaws was then performed to demonstrate that the surface flaws are likely to propagate in the through-wall direction and develop leakage before they will propagate circumferentially around the pipe. Flaw growth calculations are reported in Section 4.3, Table 4-3, of BAW-1847, Revision 1, and are based on 240 heatup and cooldown cycles and 22 cycles of safe shutdown earthquake.

As described in Section 4.3.5 , the original transient cycles that were defined for 40 years of operation for the RCS components are being monitored by ANO-1. If a transient cycle count approaches or exceeds the allowable design limit, corrective actions are taken. Therefore, the flaw growth evaluation reported in BAW-1847, Revision 1, is applicable to 60 years of operation since ANO-1 has not revised the transients defined in the RCS design specification for license renewal.

<u>Thermal Aging of Cast Austenitic Stainless Steel Reactor Coolant Pump Suction and Discharge Nozzles</u>

The susceptibility of the RCS main coolant piping to thermal aging was qualitatively addressed in Section 3.3.4.3 of BAW-1847, Revision 1. As described in BAW-2243A (Reference 4.8-1), there are no RCS main coolant piping segments fabricated from CASS. However, the heat affected zone of the welded joint that connects the wrought austenitic stainless steel 28-inch pump transition piece to the CASS reactor coolant pump inlet and exit nozzles may be susceptible to thermal embrittlement. Limited data regarding thermal aging of CASS material was available at the time of the preparation of BAW-1847, Revision 1. In the BWOG report, the values of fracture toughness for aged cast austenitic stainless steel were assumed to be bounded by the ferritic piping and ferritic weldments. Since the publication of BAW-1847, Revision 1, a significant amount of data has been obtained regarding thermal aging of CASS materials.

Test data obtained by Argonne National Laboratory [O. K. Chopra and W. J. Shack, "Assessment of Thermal Embrittlement of Cast Stainless Steels," NUREG/CR-6177, U.S. Nuclear Regulatory Commission, Washington DC, May 1994], indicate that prolonged exposure of CASS to reactor coolant operating temperatures can lead to reduction of fracture toughness by thermal embrittlement. The fracture toughness curves for the ferritic base metal and ferritic weld metals used in the reactor coolant system piping leak-before-break analysis were compared to the lower-bound fracture toughness curves of ANO-1 reactor coolant pump CASS materials (i.e., statically cast CF8M) from the Argonne report. The fracture toughness curve of the lower-bound CASS material is below the fracture toughness curves used in the RCS piping leak-before-break analysis. Therefore, the assumption in BAW-1847, Revision 1, that the fracture toughness of the ferritic piping and ferritic weldments bounds the fracture toughness of CASS materials cannot be supported.

A flaw stability analysis was performed using the lower-bound CASS fracture toughness curves from the Argonne report cited above to show acceptability of leak-before-break for the reactor coolant system main coolant piping for the period of extended operation. The most limiting material and location used in the RCS piping leak-before-break analysis (i.e., BAW-1847) was determined to be the base metal material of the straight section of the 28-inch cold leg pipe. Both the suction and discharge nozzles of the reactor coolant pump casings are attached to the 28-inch cold leg pipes and have similar geometry and loading applied to them as the limiting location used for the leak-before-break analysis. The discharge and suction nozzles of the reactor coolant pump casings were evaluated for leak-before-break using lower-bound CASS fracture toughness properties.

Bounding 10 gpm leakage crack sizes (margin of 10 on the plant's leak detection capability) for the reactor coolant pump suction and discharge nozzle were determined using a method that is consistent with that reported in BAW-1847, Revision 1. In the revised analysis, the applied loadings were considered using the absolute sum load combination method. Therefore, in accordance with SRP 3.6.3, a margin of 1.0 on load was used. The leakage crack length (twice the leakage flaw size) for the suction nozzle was determined to be 8.62 inches and the leakage crack length for the discharge nozzle was determined to be 8.86 inches. In addition, a crack extension value of 0.6 inches was considered in the flaw stability analysis. A flaw stability analysis was performed for the reactor coolant pump inlet (suction) and exit (discharge) nozzles, and the discharge nozzle was found to be limiting. The maximum applied J value at the discharge nozzle, for the 10 gpm leakage flaw size, was determined to be 0.510 kips/in. The critical crack length was determined to be 21.6 inches. Therefore, the margin on flaw size was determined to be 2.4. This is greater than the required margin of 2 in accordance with SRP 3.6.3. Based on the results of this analysis, it is concluded that all the required margins for LBB per SRP 3.6.3 are met, even with consideration of the lower bound CASS fracture toughness properties for the suction and discharge nozzles.

In addition, thermal aging of the SMAW weldment that connects the stainless steel transition pieces to the RCP nozzles was considered. The J-R curve for aged and unaged stainless steel weldments was obtained from NUREG/CR-6428, "Effects of Thermal Aging on Fracture Toughness and Charpy-Impact Strength of Stainless Steel Pipe Welds." Based on the results of this work, a conservative estimate of J-R curve for aged stainless steel welds is given by $J = 40 + 83.5\Delta a^{0.643}$ in units of kJ/m^2. The J-R curve for aged CASS CF8M material used in the LBB analysis, reported above, is given by $J=167(\Delta a)^{0.31}$, which is also given in units of kJ/m^2. As noted above, the flaw stability analysis considered a maximum crack extension of 0.6 inches (15.24 mm). The results show that the J-R curve for aged CASS material used in the LBB analysis, bounds the J-R curve for aged stainless steel weld material given in NUREG/CR-6428 at a maximum crack extension of 15.24 mm.

Summary: Leak-Before-Break for the Period of Extended Operation

In summary, demonstration that the fatigue flaw growth analysis reported in BAW-1847, Revision 1, remains valid for the period of extended operation is addressed by the ANO-1 Transient Cycle Logging and Reporting discussion in Section 4.3.5. The remainder of the generic leak-before-break analysis for the B&W operating plants reported in BAW-1847, Revision 1, remains valid for the period of extended operation with the exception of the assessment of reduction of fracture toughness by thermal aging of cast austenitic stainless steel reactor coolant pump nozzles. Reduction of fracture toughness of the reactor coolant pump nozzles was determined to be acceptable for the period of extended operation through the flaw stability analysis described above.

4.8.4 Reactor Coolant Pump Motor Flywheels

Entergy Operations identified a time-limited aging analysis with the reactor coolant pump motor. The analysis included a fatigue crack growth evaluation to determine the growth of pre-existing cracks. The crack growth evaluation was performed for 4,000 startup/shutdown cycles, which exceeds the number of design cycles for the reactor coolant pump motor by a factor of 8. Therefore, the crack growth evaluation is a time-limited aging analysis and the existing analysis is adequate for the period of extended operation. This time-limited aging analysis is acceptable per 10CFR 54.21(c)(1)(i).

4.8.5 References for Section 4.8

4.8-1 BAW-10013, "Study of Intergranular Separations in Low-Alloy Steel Heat-Affected Zones Under Austenitic Stainless Steel Weld Cladding," B&W Nuclear Power Generation, December 1971.

4.8-2 ASME Boiler and Pressure Vessel Code, American Society of Mechanical Engineers.

4.8-3 BAW-2251A, "*Demonstration of the Management of Aging Effects for the Reactor Vessel*," The B&W Owners Group Generic License Renewal Program, June 1996.

4.8-4 ASME Boiler and Pressure Vessel Code, Section XI, "*Rules for In-Service Inspection of Nuclear Power Plant Components*," American Society of Mechanical Engineers.

4.8-5 BAW-1847, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS," Revision 1, B&W Owners Group, September 1985.

4.8-6 BAW-2243A, "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," The B&W Owners Group Generic License Renewal Program, June 1996.

Appendix A

Safety Analysis Report Supplement

INTRODUCTION

This appendix contains the SAR Supplement required by 10CFR54.21(d) for the ANO-1 License Renewal Application. The LRA contains the technical information required by 10CFR54.21(a) and 10CFR54.21(c). Section 3.0 and Appendix B of the ANO-1 LRA provide descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Section 4.0 contains the evaluations of the time-limited aging analyses for the period of extended operation. These sections have been used to prepare the program and activity descriptions that are contained in the SAR Supplement. The SAR Supplement will be incorporated into the ANO-1 SAR following issuance of the renewed operating license for ANO-1. Upon inclusion of the SAR Supplement in the ANO-1 SAR, changes to the descriptions of the programs and activities will be made in accordance with 10CFR50.59.

CHAPTER 4 CHANGES

4.1.2.6 Service Lifetime

The original design service lifetime for the major RCS components ~~is~~ was 40 years. The number of cyclic system temperature, pressure, and operational changes (Table 4-8) ~~is~~ was based on operation for this design lifetime. The commencement date for the original design service life was the date of the Construction Permit which approved the PSAR for Unit 1, which is December 6, 1968. However, in 1990, per License Amendment 131, an extension was granted to allow the operating license term to be changed to start at the issuance of the operating license to allow a 40-year service life that does not include the construction time period and end on May 20, 2014. A new operating license has been granted to extend the licensed term an additional 20 years to May 20, 2034. This was justified based on design transient cycles. The reactor coolant system was originally qualified using a conservative estimate of design cycles for a 40 year life. The design life is not dependent on years of service. The design life is dependent on fatigue cycles. In evaluations performed by the NSSS vendor, the actual cycles were extrapolated to 60 years. For the major RCS components, the design cycles exceeded the estimated cycles for a 60-year life. The actual transient cycles are tracked and documented to ensure they are maintained below the allowable number of design cycles as further discussed in Section 16.2.21. Table 4-8 shows the complete listing of transients used in the design of components within the Reactor Coolant Pressure Boundary. Records of significant transients are available from the ~~daily~~ periodic reviews of the Shift Superintendent's log. A record of all significant transients is maintained by the technical support staff.

4.1.2.8 Vessel Radiation Exposure

The reactor vessel is the only RCS component exposed to a significant level of neutron irradiation and is therefore the only component subject to material radiation damage. The maximum exposure from fast neutrons (E > 1.0 MeV) has been computed to be less than 3.0×10^{19} neut/cm² over a 40-year life with an 80 percent load factor. Revised calculations, based on results of the Reactor Vessel Material Surveillance Program and reduced leakage fuel cycle configurations, indicate that the maximum exposures will be less than half of this value. The maximum inside surface fast neutron fluence at 48 EFPY is projected to be 1.44×10^{19} neut/cm². Reactor vessel irradiation calculations are described in Section 4.3.3.

4.3.3 REACTOR VESSEL

(Excerpted from Nil Ductility Transition Temperature (NDTT))

Revised calculations, based on results of the Reactor Vessel Material Surveillance Program and reduced leakage fuel cycle configurations, indicate that the maximum fluence value will be less than half of the originally estimated $3x10^{19}$n/cm². The maximum inside surface fast neutron fluence at 48 EFPY is projected to be $1.44x10^{19}$ n/cm². The corresponding EOL transition temperature is similarly reduced while the minimum upper shelf energy value is increased.

(Excerpted from Flux and Total Integrated Flux (nvt) at Reactor Vessel Wall)

Revised calculations, based on results of the Reactor Vessel Material Surveillance Program and reduced leakage fuel cycle configurations, indicate that the maximum fluence values will be less than the originally calculated values. The revised fluence value for 40 years at 80 percent load is 1.10×10^{19} n/cm². This value was used to respond to the Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock, 10CFR50.61. The projected fast fluence value has since been revised lower to 8.71×10^{18} n/cm², as reported to the NRC via 1CAN119608. The projected maximum fast fluence value for 48 EFPY has been determined to be 1.44×10^{19} n/cm².

(Excerpted from Expected NDTT Shift)

Revised values of calculated vessel exposure have been used to determine the increase in the NDTT in accordance with 10CFR50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock." The results have been reported to and accepted by the NRC (1CNA128603). For the 40-year exposure at 80 percent load, the calculated value of the NDTT is 264°F. The calculation and supporting documentation are described in BAW-1895 (Jan. 1986). "Pressurized Thermal Shock Evaluation in Accordance with 10CFR50.61 for B&W Owners Group Reactor Pressure Vessels." Since the submittal of BAW-1895, the fourth capsule report has been produced and submitted. This capsule report indicates the NDTT value is 257°F based on a further reduction in the projected fluence value.

BAW-2251-A shows the RT_{PTS} to be 278°F for 48 EFPY for a circumferential weld.

The NDTT shift is factored into the plant startup and shutdown procedures so that full operating pressure is not attained until the reactor vessel temperature is about DTT. The heatup and cooldown curves are given in Technical Specification 3.1.2, "Pressurization, Heatup and Cooldown Limitations. The total stress in the vessel wall due to both pressure and the associated heatup and cooldown transient is restricted to 5,000 - 10,000 psi, which is below the threshold of concern for safe operation. An adjusted 100°F per hour heatup rate can be maintained throughout life. An adjusted rate is one in which the pressure is held constant to maintain stresses at the desired low level while temperatures are at a level below DTT. A 100°F per hour temperature increase is maintained until DTT is passed and pressure can be raised to a new higher level. These operating restrictions are based on the NRL generalized fracture analysis diagram, which is a semi-empirical method of material selection and approximate analysis to prevent brittle fracture. This diagram plots failure stress (normalized to yield) as a function of temperature referenced to the NDTT for a family of finite flaw sizes. The parametric crack size curves were determined partially by fracture mechanics and partially by plotting actual failure data. The assumed flaw for this analysis was slightly greater than 24 inches.

CHAPTER 5 CHANGES

5.2.1.4.7.3 Loads

All load combinations are considered in the above analysis. The following fatigue loads are considered in liner design:

A. Thermal cycling due to annual outdoor temperature variations - Daily temperature variations will not penetrate a significant distance into the concrete shell to appreciably change the average temperature of the shell relative to the liner plate. The number of cycles for this loading is ~~40~~ 60 cycles for the plant life of ~~40~~ 60 years.

B. Thermal cycling due to reactor building interior temperature varying during the heatup and cooldown of the reactor system - The number of cycles for this loading is assumed to be 500.

C. One cycle was assumed for thermal cycling due to a DBA.

CHAPTER 6 CHANGES

6 ENGINEERED SAFEGUARDS

(Excerpted from Chapter 6)

Operability of engineered safeguards equipment is assured in several ways. Much of the equipment in these systems function during normal reactor operation thus providing a constant check on operational status. Where equipment is used for emergency functions only, such as in the Reactor Building Spray System, the systems have been designed to permit meaningful periodic tests. Operational reliability has been achieved by using proven component designs wherever possible and/or by conducting tests. Quality control and assurance requirements are implemented during the design, manufacture, and installation of the engineered safeguards components and systems to assure that a high quality level is maintained. The quality program is based upon the use of accepted industry codes and standards as well as supplementary test and inspections. The resultant high quality level of the components gives assurance that they will perform their intended function under the worst anticipated conditions following a LOCA. Materials for equipment required to operate under accident conditions are selected on the basis of the additional exposure received in the event of a Design Basis Accident (DBA). All equipment must ~~operate for the designed 40-year~~ remain functional throughout the life of the plant. Certain safety-related equipment must operate during the design plant life as well as function as required during and following a DBA at the end of plant life.

CHAPTER 11 CHANGES

11.2.1.2 Radiation Exposure of Materials and Components

~~No regulations similar to those established for the protection of individuals exist for materials and components. However, m~~Materials and components are selected on the basis that their design radiation exposure will not cause significant changes in their physical properties which adversely affect operation of equipment during the design life of the plant. Materials for equipment required to operate under accident conditions are selected on the basis of the additional exposure received in the event of a DBA. The approximate radiation damage threshold for various materials is shown in Table 11-13.

NEW CHAPTER 16

16.0 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The integrated plant assessment for license renewal identified several new programs and activities, modifications to existing programs, and existing programs, necessary to continue operation of ANO-1 during the additional 20 years beyond the initial license term. This chapter describes these programs and activities.

16.1 NEW ACTIVITIES

16.1.1 BURIED PIPE INSPECTION

Buried Pipe Inspections will be performed to ensure that a loss of material due to external surface corrosion of buried piping is adequately managed. The safety-related portions of underground carbon steel piping on the service water and fuel oil systems are within the scope of this inspection. The aging effect addressed by the Buried Pipe Inspection is a loss of material due to corrosion of the external surfaces of pipe caused by loss of the protective coating. This inspection will be initiated prior to the end of the initial 40-year license term.

16.1.2 ELECTRICAL COMPONENT INSPECTION

The Electrical Component Inspection Program will inspect splices, connectors, and cables located in areas that may be conducive to accelerated aging. The scope of this inspection includes cables exposed to elevated temperatures, wet environments, or corrosive chemicals. The scope also includes cables that can experience elevated temperatures due to the current they are carrying and connectors used in impedance-sensitive circuits and cable splices subject to aging-related stressors. The aging effect for cables and cable splices is a change of material properties, as evidenced by cracking or discoloration of the insulation. The aging effect for connectors in impedance-sensitive circuits is a change of material due to corrosion of connector pins. The Electrical Component Inspection Program will be formally implemented and the first inspection of in-scope cables, splices, and connectors completed prior to the expiration of the initial 40-year licensing term.

16.1.3 HEAT EXCHANGER MONITORING

The Heat Exchanger Monitoring Program will inspect heat exchangers to the extent required to ensure seismic qualification is maintained. The Heat Exchanger Monitoring Program manages aging effects on the following safety-related systems and components: reactor building coolers, emergency diesel generator jacket cooling water heat exchangers, make-up pump coolers, make-up pump room coolers, decay heat room coolers, decay heat system heat exchangers, electrical room chillers and coolers, control room chillers and coolers, and emergency feedwater turbine lube oil cooler. The aging effects addressed by the Heat Exchanger Monitoring Program are cracking or loss of material that could result in degradation in the seismic qualification of the heat exchangers. Inspection will be initiated prior to the end of the initial 40-year license term.

16.1.4 PRESSURIZER EXAMINATIONS

The Pressurizer Examinations include two specific examinations: the pressurizer cladding and the pressurizer heater penetration weld examination.

16.1.4.1 Pressurizer Cladding Examination

The pressurizer cladding examination will assess the condition of the pressurizer cladding. The scope of this activity will include the cladding and attachment welds to the cladding of the pressurizer. The aging effect is cracking of cladding by thermal fatigue, which may propagate to the underlying ferritic steel. These inspections are included in the ISI program and will be carried forward to the period of extended operation.

16.1.4.2 Pressurizer Heater Bundle Penetration Welds Examination

The pressurizer heater bundle penetration welds examination will assess the condition of the pressurizer heater penetration welds. This examination will be applicable to the heater sheath-to-diaphragm plate penetration welds inside the pressurizer. The aging effect is cracking at the heater bundle penetration welds, which may lead to reactor coolant leakage. The heater bundle examination may occur prior to entering the period of extended operation or during the period of extended operation.

16.1.5 REACTOR VESSEL INTERNALS AGING MANAGEMENT

Ongoing industry efforts are aimed at characterizing the aging effects requiring management associated with the reactor vessel internals. Further understanding of these aging effects will be developed by the industry over time and will provide additional bases for the inspections under this program. Entergy Operations will participate in the BWOG Reactor Vessel Internals Aging Management Program and other industry programs, as appropriate, to continue investigation of aging effects requiring management for the reactor vessel internals. These activities will assist in establishing appropriate monitoring and inspection programs for the reactor vessel internals. Entergy Operations will provide periodic updates after the completion of significant milestones in the preparation of the Reactor Vessel Internals Inspection, commencing within one year of the issuance of the renewed license. Entergy Operations will submit a report to the NRC, at or about, the end of the initial 40-year operating license term. This report will summarize the current understanding of aging effects applicable to the reactor vessel internals and will contain the Entergy Operations' inspection plan, including methods for each inspection. Entergy Operations will perform the Reactor Vessel Internals Inspection. Should data or evaluations indicate that this inspection can be modified or eliminated, Entergy Operations will provide plant-specific justification to demonstrate the basis for the modification or elimination. The purpose of the Reactor Vessel Internals Inspection is to inspect and examine the reactor vessel internals to assure the aging effects will not result in loss of the intended functions of the internals during the period of extended operation. The inspection applies to the reactor vessel internals. This inspection will begin during the period of extended operation. The aging effects for the reactor vessel internals include cracking due to either stress corrosion or irradiation assisted stress corrosion, reduction of fracture toughness due to irradiation embrittlement, dimensional changes due to void swelling, and loss of bolted closure integrity due to stress relaxation.

16.1.6 SPENT FUEL POOL MONITORING

The Spent Fuel Pool Monitoring Program will manage the aging effects requiring management of the ANO-1 spent fuel pool liner. Stress corrosion cracking is possible from the external surface of the liner in weld heat-affected zones since this was not verified to be chloride-free during construction. This program will be initiated before the end of the initial 40-year license term.

16.1.7 WALL THINNING INSPECTION

Wall Thinning Inspections will be performed to ensure wall thickness is above the minimum required to avoid leaks or failures under normal conditions and postulated transient and accident conditions, including seismic events. Wall Thinning Inspections cover the following safety-related systems and components: EFW pump casing and carbon steel discharge piping and valves, EFW steam supply components downstream of steam admission valves, EFW steam exhaust piping and valves, carbon steel cooling water, seal water, and instrument piping and valves, turbine lube oil cooler, carbon steel EFW supply header piping and valves (condensate supply), NaOH tank, carbon steel piping and components, and carbon steel components of penetrations 11, 42, 43, 48, 49, 51, 52, 54, 58, 59, 60, 62, and 64. The aging effect to be addressed by Wall Thinning Inspection is a loss of material due to corrosion of the internal surfaces of carbon steel piping and components.

16.2 EXISTING ACTIVITIES

16.2.1 ALLOY 600 AGING MANAGEMENT

The Alloy 600 Aging Management Program will manage cracking by PWSCC of Alloy 600 and Alloy 82/182 locations for the period of extended operation. The Alloy 600 Aging Management Program will be applicable to the Alloy 600 items and Alloy 82/182 weld material in the RCS, including the hot leg flow meter element. The aging effect managed by the Alloy 600 Aging Management Program is cracking of Alloy 600 items and Alloy 82/182 weld material in the RCS.

16.2.2 ALTERNATE AC DIESEL GENERATOR TESTING AND INSPECTIONS

The Alternate AC Diesel Generator Testing and Inspections ensures that the effects of aging are managed before the loss of the intended functions of the system. The Alternate AC Diesel Generator Testing and Inspections applies to the station blackout diesel and its components. The aging effects addressed by the Alternate AC Diesel Generator Testing and Inspections include: loss of material or loss of mechanical closure integrity for the starting air subsystem components; loss of material or loss of mechanical closure integrity for the intake combustion air subsystem components; loss of material, fouling, and loss of mechanical closure integrity for the intake air aftercooler; loss of material for carbon steel components, cracking of the stainless steel components, or loss of mechanical closure integrity for the exhaust subsystem components; loss of mechanical closure integrity for the lube oil subsystem components; fouling, loss of material from wear, and loss of mechanical closure integrity for the lube oil cooler; loss of material and loss of mechanical closure integrity for the cooling water subsystem components; fouling and a loss of material for the AAC radiator; loss of material from wetted portions of the exhaust fan housings; and fouling of the fuel oil heat exchanger.

16.2.3 ASME SECTION XI INSERVICE INSPECTION

16.2.3.1 <u>IWB Inspections</u>

The ASME Section XI, Subsection IWB Inspections under the scope of the Inservice Inspection Plan identifies and corrects degradation of ASME Class 1 pressure retaining components and their integral attachments. The scope of the ASME Section XI, Subsection IWB Inspections, credited for license renewal, is identified specifically for each component and for applicable component features in the ISI Plan. The aging effects managed as part of the ASME Section XI, Subsection IWB Inspections include cracking, loss of mechanical closure integrity at bolted connections, and loss of material. In addition, a one-time visual inspection of a reactor coolant pump casing will be performed prior to the end of the initial 40-year license term.

16.2.3.2 <u>IWC Inspections</u>

ASME Section XI, Subsection IWC Inspections under the scope of the ANO-1 Inservice Inspection Plan identify and correct degradation of ASME Class 2 pressure retaining components and their integral attachments. The scope of the ASME Section XI, Subsection IWC Inspections, credited for license renewal, includes components on the following systems: core flood, RBS, main feedwater, spent fuel, service water, HPI/makeup and purification, LPI/decay heat, EFW, main steam, reactor building isolation, and chilled water system. The aging effects managed as part of the ASME Section XI, Subsection IWC Inspections include cracking, loss of mechanical closure integrity, and loss of material.

16.2.3.3 IWD Inspections

ASME Section XI, Subsection IWD Inspections under the scope of the Inservice Inspection Plan identify and correct degradation of ASME Class 3 pressure-retaining components. The scope of the ASME Section XI, Subsection IWD Inspections, credited for license renewal, includes components on the following systems: service water, spent fuel, main steam, EFW, sodium hydroxide, and condensate storage. The aging effects managed as part of the ASME Section XI, Subsection IWD Inspections include cracking, loss of mechanical closure integrity, and loss of material.

16.2.3.4 IWE Inspections

ASME Section XI, Subsection IWE Inspections under the scope of the Inservice Inspection Plan identify and correct degradation of Class MC pressure retaining components, their integral attachments, the metallic shell and penetration liners of Class CC pressure retaining components, and their integral attachments. The scope of the ASME Section XI, Subsection IWE Inspections, credited for license renewal includes inspections of the reactor building liner plate. The aging effect managed as part of the ASME Section XI, Subsection IWE Inspections is a loss of material of the steel surfaces.

16.2.3.5 IWF Inspections

ASME Section XI Inservice Inspection Program, IWF Inspections identify and correct degradation of ASME Class 1, 2, 3, or MC component supports. The aging effects managed as part of the ASME Section XI, Subsection IWF include cracking, loss of material, and change in material properties.

16.2.3.6 IWL Inspections

ASME Section XI Inservice Inspection Program, IWL Inspections provides instructions and documentation requirements for assessing the quality and structural performance of the reactor building's post-tensioning systems and concrete components. The scope includes the concrete reactor building's post-tensioning systems and reinforced concrete components. The aging effects are loss of material for tendon anchorage and cracking and change in material properties for concrete.

16.2.3.7 Augmented Inspections

The ASME Section XI, Augmented Inspections identify and correct degradation of components outside of the jurisdiction of ASME Section XI. Augmented periodic inspections are completed for several main feedwater and main steam system welds, not in the Class 2 piping, to support the high energy line break analysis. Augmented inspections are completed for the BWST header including the lines from the reactor building sump. Augmented inspections that will be added to the program because of license renewal include a special augmented inspection on the welds of the piping wetted by the reactor building sump water, some supplemental inspections of the "Q" stainless piping of the main steam system, at least a one-time inspection of the penetration 68 piping and components and the decay heat pump room drain valves, and special inspections of penetrations 10, 47, 58, and 64. The aging effects managed by these inspections are cracking and a loss of material. The new inspections will be initiated prior to the end of the initial 40-year license term.

16.2.3.8 Small Bore Piping and Small Bore Nozzles Inspections

The Small Bore Piping and Small Bore Nozzles Inspections identify aging effects on small bore piping and nozzles. The small bore piping and small bore nozzles, within the scope of this program, are RCS piping and nozzles less than 4-inch NPS that do not receive volumetric inspection in accordance with ASME Section XI. The aging effect managed by this program is cracking. A risk-informed ISI method has been implemented to select RCS piping welds for inspection. The risk-informed approach consists of two essential elements. A degradation mechanism evaluation is performed to assess the failure potential of the piping system under consideration, and a consequence evaluation is performed to assess the impact on plant safety in the event of a piping failure. The results from these two independent evaluations are coupled to determine the risk significance of piping segments within the system, and priority is then given to the most risk significant piping segments during the selection of RCS piping welds for inspection.

16.2.4 BOLTING AND TORQUING ACTIVITIES

Bolting and Torquing Activities prevent degradation of bolting or identify and correct degradation of bolting. The scope of Bolting and Torquing Activities applies to pressure boundary bolting applications associated with components within the scope of license renewal. Applications include bolted flange connects for vessels (i.e., manways and inspection ports), flanged joints in piping, body-to-body joints in valves, and pressure-retaining bolting associated with pumps or valves and miscellaneous process components. The aging effects addressed by Bolting and Torquing Activities are cracking, loss of material, and loss of mechanical closure integrity.

16.2.5 BORIC ACID CORROSION PREVENTION

The Boric Acid Corrosion Prevention Program prevents corrosion damage due to leakage from the borated water systems. The Boric Acid Corrosion Prevention Program is concerned with the RCS and other structures and components containing, or exposed to, borated water. This program is credited with monitoring the boric acid corrosion of carbon steel external surfaces of structures and components exposed to leakage from borated water. Carbon steel is utilized for bolting on many of the systems that contain borated water. This program manages the loss of material of bolts that could eventually result in a loss of pressure integrity for bolted connections.

16.2.6 CHEMISTRY CONTROL

The following subsections address the individual ANO-specific chemistry control programs in more detail:

- Primary Chemistry Monitoring
- Secondary Chemistry Monitoring
- Auxiliary Systems Chemistry Monitoring
- Diesel Fuel Monitoring
- Service Water Chemical Control

16.2.6.1 Primary Chemistry Monitoring

The Primary Chemistry Monitoring Program maximizes long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up. The scope of the Primary Chemistry Monitoring Program includes sampling activities and analysis on the following systems: RCS, borated water storage tanks, spent fuel pool system, letdown purification demineralizers, and reactor makeup water. The Primary Chemistry Monitoring Program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

16.2.6.2 Secondary Chemistry Monitoring

The Secondary Chemistry Monitoring Program maximizes the availability and operating life of major components. The scope of the Secondary Chemistry Monitoring Program includes sampling activities and analysis on the main feedwater system, condensate storage system, and steam generators. The aging reviews for many of the safety-related, non-Class 1 systems also indirectly credit the Secondary Chemistry Monitoring Program since the condensate storage tanks are used as a source of makeup water to these systems. The Secondary Water Chemistry Monitoring Program ensures the levels of contaminants and oxygen are maintained within a range that prevents or minimizes the occurrence of loss of material and other aging effects.

16.2.6.3 Auxiliary Systems Chemistry Monitoring

The Auxiliary Systems Chemistry Monitoring Program maximizes the availability and operating life of the components used for the closed cooling loops. The scope of the Auxiliary Systems Chemistry Monitoring Program is limited to sampling activities and analysis on the ICW system, chilled water systems, emergency diesel generators, and the AAC diesel generator. The Auxiliary Systems Chemistry Monitoring Program is credited with minimizing the loss of material due to corrosion, cracking, fouling, and loss of mechanical closure integrity.

16.2.6.4 Diesel Fuel Monitoring

The Diesel Fuel Monitoring Program ensures that adequate diesel fuel quality is maintained to prevent plugging of filters, fouling of injectors, and corrosion of the fuel systems. The scope of the Diesel Fuel Monitoring Program is limited to sampling activities and analysis on the following tanks: bulk fuel oil storage tank, EDG fuel tanks, EDG day tanks, fire pump diesel day tank, and the AAC diesel generator day tank. The aging management reviews credit the sampling and monitoring as providing an adequate control of the fuel oil to ensure water and contamination (including microbiological) are not present in the system.

16.2.6.5 Service Water Chemical Control

The Service Water Chemical Control Program maximizes the availability and operating life of the components in the service water system. The scope of the Service Water Chemical Control Program includes sampling activities and analysis on the service water system. The scope also includes chemical injection into the service water bays. The fire protection system takes suction from the service water bays. The Service Water Chemical Control Program has been credited for aging management in the service water system, auxiliary cooling water system, and the fire protection system since these systems draw suction from the intake structure. The chemical additions are only credited with reducing corrosion, not eliminating this mechanism.

16.2.7 CONTROL ROD DRIVE MECHANISM NOZZLE AND OTHER VESSEL CLOSURE PENETRATIONS INSPECTION

The CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program verifies the assumptions made in the BWOG safety evaluation of the susceptibility and consequence of PWSCC in B&W-designed CRDM nozzles. The scope of the program includes the B&W-designed reactor vessel closure head CRDM nozzles and other closure head penetrations. The aging effect is PWSCC of Alloy-600 nozzles with partial penetration welds that cause high circumferential residual stresses on the inner diameter of the nozzles opposite the welds.

16.2.8 FIRE PROTECTION

Fire Protection Program activities, with respect to aging management, include: fire barrier inspections, fire hose station inspections, fire suppression water supply system surveillance, fire suppression sprinkler system surveillance, fire water piping thickness evaluation, control room halon fire system inspection, NFPA 25 testing of sprinkler head components that are 50 years old, and RCP oil collection system visual inspection.

16.2.8.1 Fire Barrier Inspections

Fire Barrier Inspections provide for periodic surveillance of fire barriers separating redundant safe shutdown systems to assure that they perform their separation functions. The scope includes 10CFR50.48-required fire walls and fire floors as indicated on the fire protection drawings. Fire doors/hatches, fire damper mountings, fire wraps, and penetration fire stops associated with 10CFR50.48-required fire walls and fire floors are within the scope. The aging effects for fire barriers are cracking, loss of material, and change in material properties.

16.2.8.2 Fire Hose Station Inspections

The Fire Hose Station Inspections assure that manual fire suppression is available to safety-related equipment. Fire hose reels associated with 10CFR50.48-required fire hose stations are within the scope of license renewal. The aging effect for fire hose reels is a loss of material.

16.2.8.3 Fire Suppression Water Supply System Surveillance

This surveillance verifies operability of fire suppression water supply system components. The Fire Suppression Water Supply System Surveillance applies to fire water system supply piping and valves. The surveillance applies to several diesel fire pump subsystems including the intake air, exhaust, lube oil, and cooling water. Fire protection system heat exchangers are also within the scope of this surveillance. This program verifies that loss of material due to internal surface corrosion and fouling of carbon steel, stainless steel, brass, or bronze components is managed. Cracking of stainless steel, brass or bronze components is also an aging effect being managed.

16.2.8.4 Fire Suppression Sprinkler System Surveillance

This surveillance verifies operability of fire suppression sprinkler system components. Within the scope of license renewal, the Fire Suppression Sprinkler System Surveillance applies to fire suppression sprinkler system piping, valves, and nozzles. This surveillance verifies that loss of material due to internal surface corrosion and fouling of carbon steel, stainless steel, brass or bronze components is managed. Cracking of stainless steel, brass, or bronze components is also an aging effect being managed.

16.2.8.5 Fire Water Piping Thickness Evaluation

The Fire Water Piping Thickness Evaluation provides a method for the examination and evaluation of pipe wall thickness changes in the fire water system. Within the scope of license renewal, the Fire Water Piping Thickness Evaluation applies to fire water system piping. A loss of material by internal surface corrosion of cast iron, carbon steel, or stainless steel fire water system components is the aging effect managed by the Fire Water Piping Thickness Evaluation.

16.2.8.6 Control Room Halon Fire System Inspection

The Control Room Halon Fire System Inspection assures that frequently manipulated components are free of aging effects. The components within the scope of the Control Room Halon Fire System Inspection are the halon discharge tube assembly and the halon pilot header flexible tubing and fittings and discharge tube assembly fittings. The aging effects addressed by the Control Room Halon Fire System Inspection are loss of material due to wear from frequent manipulations and cracking.

16.2.8.7 Reactor Coolant Pump Oil Collection System Visual Inspection

The Reactor Coolant Pump Oil Collection System Inspection ensures integrity of the reactor coolant pump oil leakage collection system. The Reactor Coolant Pump Oil Collection System Inspection applies to the shrouds, drip pans, dammed areas, accessible piping, collection tanks, and spray protection. The aging effects addressed by the Reactor Coolant Pump Oil Collection System Inspection are a loss of material and a loss of mechanical closure integrity. These aging effects would be caused by general corrosion of the carbon steel internal surfaces or external surfaces due to the potential for water leakage into the system.

16.2.9 FLOW ACCELERATED CORROSION PREVENTION

The Flow Accelerated Corrosion Prevention Program provides a programmatic approach for identifying, inspecting, and managing loss of material for components that are adversely affected by flow accelerated corrosion (also known as erosion/corrosion). Within the scope of license renewal, only the main feedwater and main steam systems are identified as susceptible to flow-accelerated corrosion. The aging effect is a phenomenon that results in metal loss from components made of carbon steel, which occurs only under certain conditions of flow, chemistry, geometry, and material. The aging management reviews credit this program with determining which systems are susceptible to flow-accelerated corrosion and monitoring the loss of material for those systems.

16.2.10 INSPECTION AND PREVENTIVE MAINTENANCE OF THE POLAR CRANE

The program provides for the inspection and preventive maintenance of the polar crane. The scope of this program includes the structural steel associated with the polar crane. The aging effect managed by the Inspection and Preventive Maintenance of the Polar Crane is a loss of material.

16.2.11 INSTRUMENT AIR QUALITY

With respect to license renewal, the Instrument Air Quality Program ensures that the instrument air supplied to components is maintained free of water and significant contaminants. The Instrument Air Quality Program applies to those components, within the scope of license renewal, supplied with instrument air where pressure boundary integrity is required for the component to perform its intended function. The aging effects requiring management addressed by the Instrument Air Quality Program are loss of material and cracking.

16.2.12 LEAKAGE DETECTION IN REACTOR BUILDING

Leakage detection in the reactor building monitors leakage to manage the consequences of cracking, loss of material, or loss of mechanical closure integrity. Leakage detection in the reactor building is focused on RCS leakage, but also includes other systems that have the potential to leak in the reactor building.

16.2.13 MAINTENANCE RULE

Maintenance Rule system and structural walk downs are conducted to detect and manage aging effects of structures and components within the scope of the license renewal. This includes coatings inspections of coated surfaces on structures and components. The Maintenance Rule is utilized to manage cracking, loss of material, and change in material properties of structures and components within the scope of license renewal.

16.2.14 OIL ANALYSIS

The Oil Analysis Program ensures the oil environment in the mechanical systems is maintained to the quality required. Oil analysis program controls are credited as a program for maintaining oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to corrosion. The scope of the Oil Analysis Program, with respect to license renewal, is limited to sampling activities and analysis on the auxiliary building electrical room chillers, emergency diesel generators, decay heat pumps, reactor building spray pumps, primary makeup pumps, diesel driven fire pump and engine, EFW pumps and turbine, the AAC diesel generator, and the control room chiller compressor. The Oil Analysis Program has been credited for ensuring the oil is free of water or contaminants. This manages the aging effects of cracking and loss of material.

16.2.15 PREVENTIVE MAINTENANCE

The purpose of the Preventive Maintenance Program is to perform preplanned, repetitive maintenance tasks on plant components and systems to extend equipment operating-life and to minimize the possibility of in-service component failures. The scope of the Preventive Maintenance Program, with regard to license renewal, is the preventive maintenance tasks credited with managing the aging effects listed below:

Preventive Maintenance Activity	Aging Effect
BWST internal inspection	Loss of material
BWST external inspection	Loss of material and loss of mechanical closure integrity
Reactor building ventilation cooling coil cleaning and inspection	Fouling and loss of material
Hydrogen sampling system cabinet/heat exchanger cleaning, inspection, and lubrication	Fouling
Emergency fire diesel cooling water quarterly sampling for corrosion inhibitor	Loss of material
Penetration room floor drain check valves inspection	Loss of material and cracking
Decay heat room drain valves inspection	Loss of material, cracking, and loss of mechanical closure integrity
EDG fuel oil tank inspection	Loss of material
EDG HVAC components inspection	Loss of material and loss of mechanical closure integrity
Control room ventilation inspections	Fouling and loss of material
Battery Charger and Penetration Room Cooler Cleaning and Inspection	Loss of material and loss of mechanical closure integrity
Auxiliary Building Switchgear Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling

Preventive Maintenance Activity	Aging Effect
Auxiliary Building Decay and Heat Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling
HPI Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling

16.2.16 REACTOR BUILDING LEAK RATE TESTING

The Reactor Building Leak Rate Testing Program provides assurance that leakage from the reactor building does not exceed required maximum values for reactor building leakage. The Reactor Building Leak Rate Testing Program is comprised of Integrated Leak Rate Testing and Local Leak Rate Testing. The integrated leak rate test measures the primary reactor building overall integrated leakage rate. The scope of the integrated leak rate test is the entire reactor building. Integrated leak rate testing identifies loss of material or cracking. The local leak rate test measures the leakage across individual penetration components and determines the leakage of each penetration. Local leak rate testing identifies changes in material properties, loss of material, and cracking.

16.2.17 REACTOR BUILDING SUMP CLOSEOUT INSPECTION

The Reactor Building Sump Closeout Inspection detects significant degradation of the sump components and removes foreign objects that could impede suction from the sump. The scope of the Reactor Building Sump Closeout Inspection applies to reactor building sump, the area immediately surrounding the sump, the screening materials, and the equipment inside the sump. The aging effects addressed by the Reactor Building Sump Closeout Inspection are loss of material for the carbon steel components and cracking for stainless steel components due to the presence of borated water.

16.2.18 REACTOR VESSEL INTEGRITY

The ANO-1 Reactor Vessel Integrity Program consists of the following five interrelated subprograms:

- Master Integrated Reactor Vessel Surveillance Program (MIRVP)
- Cavity Dosimetry Program
- Fluence and Uncertainty Calculations
- Pressure/Temperature Limits
- Monitoring Effective Full Power Years

The purpose of the MIRVP is to monitor reactor pressure vessel materials containing Linde 80 high copper beltline welds to determine the reduction of material toughness by neutron irradiation embrittlement. The purpose of the Cavity Dosimetry Program is to verify the accuracy of fluence calculations and to determine fluence uncertainty values. The purpose of the reactor vessel fluence and uncertainty calculations is to provide an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value, for use in development of the pressure/temperature limit curves and pressurized thermal shock calculations. The purpose of the pressure/temperature limit curves is to establish the normal operating limits for the RCS. The pressure/temperature limit curves apply to the reactor vessel. The purpose of determining the EFPY is to accurately monitor and tabulate the accumulated operating time experienced by the reactor vessel. The reduction of material toughness by neutron irradiation embrittlement is the aging effect addressed by these five subprograms.

16.2.19 SERVICE WATER INTEGRITY

The service water integrity program ensures the service water system components continue to operate and perform their safety-related functions for the remaining life of ANO-1. The scope of the Service Water Integrity Program, with respect to license renewal, is limited to activities on service water system components and structures, including the emergency cooling pond. The Service Water Integrity Program has been credited with managing the following aging effects:

- The flow rate testing ensures the effects of fouling do not reduce flow rates below required values.
- The heat exchanger testing manages the aging effect of fouling by ensuring the heat exchangers can remove the necessary heat load.
- The thickness mapping and visual inspections manage the aging effects of loss of material from the service water components.
- Visual inspections of a sample of safety-related valves and heat exchangers manage the effect of cracking of the components.
- The service water bay inspection is credited for managing loss of material of the mechanical components in the service water bay.

16.2.20 STEAM GENERATOR INTEGRITY

The Steam Generator Integrity Program ensures the steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The Steam Generator Integrity Program applies to the steam generator internals, tubing, and associated repair techniques and components, such as plugs and sleeves. The aging effects addressed by the Steam Generator Integrity Program are loss of material, cracking, and fouling.

16.2.21 SYSTEM AND COMPONENT MONITORING, INSPECTIONS, AND TESTING

16.2.21.1 Annual Emergency Cooling Pond Sounding

This program verifies the availability of a sufficient supply of cooling water in the emergency cooling pond to handle design basis accidents, with a concurrent loss of Lake Dardanelle. The scope includes the emergency cooling pond and surrounding structural components. The aging effect managed by this program is a loss of form of the emergency cooling pond due to sedimentation.

16.2.21.2 Battery Quarterly Surveillance

The battery rack inspections ensure their structural integrity. Seismically-qualified battery racks are within the scope. Battery racks and associated threaded fasteners are inspected for physical damage or abnormal deterioration including a loss of material.

16.2.21.3 Control Room Ventilation Testing

With respect to license renewal, the Control Room Ventilation Testing is credited as one of the programs to manage the aging effects. The control room ventilation testing applies to the control room emergency cooling coils. Fouling on the external surfaces of the cooling coil tubes is the aging effect managed by this program.

16.2.21.4 Core Flood Tank Monitoring

With respect to license renewal, the core flood tank monitoring provides a method to manage the aging effect of loss of material due to boric acid corrosion. The core flood tank monitoring applies to both core flood tanks. The loss of material due to boric acid corrosion on parts wetted by leaks from the core flood tanks may be detected through core flood tank monitoring.

16.2.21.5 Emergency Diesel Generator Testing and Inspections

With respect to license renewal, EDG Testing and Inspections provide a means of detecting aging effects associated with the various emergency diesel generator subsystems. The scope for these activities includes the emergency diesel generator assembly and associated support components. Loss of material is an aging effect for the carbon steel components in the EDG starting air system. Loss of material is identified as an aging effect for the unpainted carbon steel internal surfaces and the outer portion of the intake that could be wetted by rain. Loss of material and fouling are considered aging effects for the EDG intake air after coolers. Loss of material from the piping and muffler internal surfaces and from external surfaces exposed to the weather is an aging effect for the EDG exhaust components. Loss of material and fouling are aging effects for the lube oil coolers. The cooling water carbon steel components are susceptible to a limited loss of material from corrosion and the stainless steel components have the aging effect of cracking. Loss of material and fouling are aging effects for the cooling water heat exchangers. Since the portions of the subsystems on the engine are exposed to high vibration, loss of bolted closure integrity was identified as an aging effect for the skid mounted and connected components.

16.2.21.6 Emergency Feedwater Pump Testing

With respect to license renewal, the Emergency Feedwater Pump Testing is credited as one of the programs for managing the effects of aging. The scope includes the turbine and electric motor driven EFW pumps and associated components. Fouling in the system heat exchangers is the primary aging effect that this testing will identify. This testing also is credited with identifying the aging effects of loss of material and loss of mechanical closure integrity for system components.

16.2.21.7 NaOH Tank Level Monitoring

The NaOH tank level monitoring provides a method of detecting changes in the tank level that might indicate leakage from the NaOH tank or system. The NaOH tank level monitoring applies to the NaOH system components. This inspection is credited with managing the aging effects of loss of material, loss of mechanical closure integrity, and cracking.

16.2.21.8 Spent Fuel Pool Level Monitoring

The spent fuel pool level monitoring provides a method of detecting changes in the spent fuel pool level that might indicate cracks in the spent fuel pool liner. The spent fuel pool level monitoring applies to the detection of leakage through the spent fuel pool liner. Cracking of the spent fuel pool liner is the aging effect addressed by spent fuel pool level monitoring.

16.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

16.3.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT

The reactor vessel is described in Sections 4.3.3. Time-limited aging analyses applicable to the reactor vessel are:

- neutron embrittlement of the beltline region, including pressurized thermal shock and Charpy upper-shelf energy reduction; and
- intergranular separation in the heat affected zone of low alloy steel under austenitic stainless steel weld cladding is addressed in Section 16.3.7.

The Reactor Vessel Integrity Program as described in Section 16.2.18 is being utilized to ensure that the time dependent parameters used in the time-limited aging analysis evaluations for pressurized thermal shock and Charpy upper-shelf energy reduction are tracked such that the time-limited aging analysis remains valid through the period of extended operation.

16.3.2 METAL FATIGUE

Cyclic loads are described in Section 4.1.2.4. For the extension of plant service-life from 40 years to 60 years, metal fatigue resulting from thermal transient cyclic loads is considered a time-limited aging analysis as defined by 10CFR54.21(c). The time-limited aging analysis requires metal fatigue evaluations to remain valid for the period of extended operation. This is achieved by maintaining adequate documentation of fatigue stress analyses to show the allowable design cycles of the RCS components for the applicable transient events and monitoring or tracking the actual operating cycles to ensure the allowable cycles are not exceeded. Fatigue evaluations are performed based on the design-allowable cycles specified in Table 4-8 and the NSSS vendor functional specification. As such, the fatigue evaluations and the fatigue life of the RCS components are dependent on the actual operating cycles and independent of the service-life of the plant. As long as the number of applicable transient cycles are below the design-allowable cycles, the fatigue evaluations originally performed for a 40-year plant service-life are applicable for the 60-year plant service-life. Transient cycle logging will be maintained to ensure the fatigue analysis assumptions remain valid during the period of extended operation.

In addition to the fatigue analysis, credit is taken for risk-informed inservice inspection of the pressurizer surge line, HPI nozzles, and decay heat removal suction line to manage the potential effects of environmentally assisted fatigue. The risk-informed inservice inspections also address commitments for augmented inspections related to NRC Bulletins 88-08 and 88-11. Additional augmented inspections related to the HPI/MU nozzles in B&W plants will be continued during the period of extended operation.

16.3.3 ENVIRONMENTAL QUALIFICATION

Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses. Equipment covered by the EQ Program has been evaluated to determine if existing EQ aging analyses can be projected to the end of the period of extended operation by re-analysis or additional analysis. Qualification into the license renewal period will be treated the same as equipment initially qualified for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding the qualified life in accordance with the EQ Program.

16.3.4 CONCRETE REACTOR BUILDING TENDON PRESTRESS

The analysis of tendon prestress over the original license term is a time-limited aging analysis that was performed at the time of initial licensing. The containment tendon elements are acceptable for the period of extended operation based on projected tendon relaxation. In addition, the ASME Section XI, Inservice Inspection Program IWL inspections will be adequate to manage the effects of aging on the intended function for the period of extended operation.

16.3.5 REACTOR BUILDING LINER PLATE FATIGUE ANALYSIS

Several thermal cycling conditions, which include annual outdoor temperature variations, changes in interior temperature during start-up and shutdown of the reactor coolant system, and DBA conditions were considered in the fatigue analysis of the liner plate. This analysis is a time-limited aging analysis. The projected number of cycles for these loadings for 60 years is bounded by the existing fatigue analysis. Therefore, the original design assumptions for addressing thermal fatigue of the liner plate and piping penetrations remain valid for the period of extended operation.

16.3.6 AGING OF BORAFLEX IN SPENT FUEL POOL RACKS

The Boraflex in the spent fuel pool racks is discussed in Section 9.6.2.3. Potential stressors for the Boraflex in the spent fuel pool racks include gamma flux, which changes the material characteristics of the base polymer, and chemical environment, from the exposure to borated water. Continued monitoring and analyses of the Boraflex degradation was committed to in response to Generic Letter 96-04. In order to ensure that the 5 percent subcriticality margin can be maintained for the life of the spent fuel storage racks, the existing coupon monitoring program will be continued. Spent fuel pool silica levels will continue to be monitored and silica evaluations will continue to be performed in order to confirm that the 5 percent subcriticality margin will be maintained through the next evaluation period. These reanalysis and sampling actions provide reasonable assurance that the effects of aging on the Boraflex in the spent fuel pool racks will be adequately managed for the period of extended operation.

16.3.7 REACTOR VESSEL UNDERCLAD CRACKING

Intergranular separations (underclad cracking) in low alloy steel heat-affected zones under austenitic stainless steel weld claddings were detected in SA-508, Class-2 reactor vessel forgings manufactured to a coarse grain practice and clad by high-heat-input submerged arc processes. BAW-10013 contains a fracture mechanics analysis that demonstrates the critical crack size required to initiate fast fracture is several orders of magnitude greater than the assumed maximum flaw size, plus predicted flaw growth due to design fatigue cycles. The flaw growth analysis was performed for a 40-year cyclic loading, and an end-of-life assessment of radiation embrittlement (i.e., fluence at 32 EFPY) was used to determine fracture toughness properties. The report concluded that the intergranular separation found in B&W vessels would not lead to vessel failure. This conclusion was accepted by the AEC. To cover the period of extended operation, an analysis was performed using current ASME Code requirements. This analysis is fully described in BAW-2251A. The maximum applied stress intensity factor for the emergency and faulted conditions occurs in the closure head to head flange region and the fracture toughness margin was determined to be 2.24, which is greater than the IWB-3612 acceptance criterion of 1.41. It is therefore concluded that the postulated intergranular separations in the ANO-1 reactor vessel 508 Class-2 forgings are acceptable for continued safe operation through the period of extended operation.

16.3.8 REACTOR VESSEL NOZZLES – FLOW-INDUCED VIBRATION ENDURANCE LIMIT

Report BAW-10051, "Flow Induced Vibration Endurance Limit Assumptions," calculated stress values for the reactor vessel incore nozzles and compared them to endurance limit (stress) values. These endurance limit values were based on an assumed value of 10^{12} cycles for 40 years of operation. The number of fatigue cycles was extended for 60 years, and the component item stress values were compared to the recalculated endurance limit values and shown to be acceptable.

16.3.9 LEAK-BEFORE-BREAK

The successful application of leak-before-break to the main RCS piping is described in report BAW-1847 "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS." This report provides the technical basis for evaluating postulated flaw growth in the main RCS piping under normal plus faulted loading conditions. LBB LOCA loadings are considered for the faulted analyses of fuel assemblies as described in Section 3.3.3.3.2.1, and LBB is credited in the Section 4.2.6.6 to justify pipe whip restraints being no longer required on the main RCS piping and may be removed as needed to facilitate maintenance or other activities. In addition, the analysis of reactor building internal pressure differentials following a LOCA applies LBB in the selection of breaks to be analyzed (see Section 14.2.2.5.5.2). In summary, analyses have been performed to demonstrate that LBB remains valid for the period of extended operation.

16.3.10 RCP MOTOR FLYWHEEL

Flaw growth analysis associated with the RCP motor flywheel is a time-limited aging analysis. The analysis for fatigue crack growth addresses the growth of pre-existing cracks. The crack growth analysis was performed for 4,000 startup/shutdown cycles for the RCP motors, which exceeds the number of design cycles by a factor of eight. Therefore, the existing crack growth analysis remains valid for the period of extended operation.

Appendix B

Aging Management Programs and Activities

1.0 INTRODUCTION

The ANO-1 Integrated Plant Assessment comprises four major activities. The first two activities, "Identification of Structures and Components that are Subject to Aging Management Review," and "Identification of Aging Effects Requiring Management," have been described previously in the body of the LRA. The third major activity of the ANO-1 IPA is the identification of plant-specific programs and activities that will manage the aging effects identified as requiring management. These programs and activities are described in this appendix, "Aging Management Programs and Activities." The fourth major activity of the ANO-1 IPA, the aging management demonstration for programs and activities, is also presented in this appendix.

The ANO-1 programs and activities that are credited for managing aging may be divided into new actions and existing actions. The new programs and activities are described in Section 3.0 of this appendix. The existing programs and activities are described in Section 4.0 of this appendix. The descriptions have used a series of specific attributes to facilitate the description of the programs and activities. These attributes are defined in Section 2.0. Summary descriptions of new and existing programs and activities are contained in the ANO-1 SAR Supplement, which is provided in Appendix A of the LRA.

ANO-1 programs and activities that are credited during the aging management review are described in this appendix. These programs and activities provide reasonable assurance that the effects of aging will be adequately managed so that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The demonstrations, along with the program and activity descriptions, meet the requirements specified in 10CFR54.21(a)(3). Along with the technical information contained in the body of the LRA, this appendix is intended to allow the NRC to make the finding contained in 10CFR54.29(a)(1).

2.0 PROGRAM AND ACTIVITY ATTRIBUTES

The attributes that are used to describe aging management programs and activities are described in this section. NEI 95-10, Revision 0, Sections 4.2 and 4.3 [Reference B-1] and the Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants [Reference B-2] served as primary inputs to the attribute definitions used in this appendix.

Two attributes common to all programs and activities described in this appendix are corrective actions and administrative controls. The Entergy Quality Assurance Program applies to ANO-1 safety related structures and components. Corrective actions and administrative (document) control for both safety related and non-safety related structures and components are accomplished per the existing ANO corrective action program and the ANO document control program. These two programs apply to the corrective actions and administrative controls for the programs and activities within the scope of license renewal. Accordingly, discussion of corrective actions and administrative control is not included in the summary descriptions of the individual programs and activities in this appendix.

The remaining attribute definitions used to describe new and existing programs and activities are provided below.

Purpose: A clear statement of the reason why the program or activity exists for ANO-1 license renewal.

Scope: A description of the ANO-1 structures and components within the scope of license renewal and subject to an aging management review that are encompassed by the program or activity.

Aging Effects: A description of the aging effects requiring management or the relevant physical conditions to be monitored for the identified scope of structures and components.

Method: A description of the type of action or technique used to identify or manage the aging effects or relevant conditions (e.g., visual examination of the component).

Sample Size: For new programs or activities, a sample can be identified from the total population of affected structures and components for inspection or monitoring. If a sample is chosen for inspection or monitoring, a description of the sample is provided.

Industry Codes or Standards: A description of an industry code (e.g., ASME Section XI, IEEE) or an industry standard (e.g., ASTM or NRC-approved BWOG report) that guides or governs the program or activity. This attribute may not be applicable to some programs and activities.

Frequency: A description of the frequency of action that is established for detection of aging effects or relevant physical conditions.

Acceptance Criteria or Standard: Acceptance criteria or standards are described for the relevant conditions to be monitored or the chosen examination methods.

Timing of New Program or Activity: For new or modified programs or activities, an identification of the specific timing for the implementation or modification of the program or activity.

Regulatory Basis: For existing programs and activities, an identification of any existing regulatory basis for these actions, such as the technical specifications. This attribute may not be applicable to some programs and activities.

Operating Experience and Demonstration: (For existing programs and activities) A demonstration that the program or activity can adequately manage the aging effects. In addition, operating experience relevant to the demonstration is provided.

Demonstration: (For new programs and activities) A demonstration that the program or activity can adequately manage the aging effects.

3.0 NEW ACTIVITIES

3.1 BURIED PIPE INSPECTION

Purpose: Buried Pipe Inspections will be performed to ensure that a loss of material due to external surface corrosion of buried piping is adequately managed.

Scope: The safety-related portions of underground carbon steel piping on the ANO-1 service water and fuel oil systems are within the scope of this inspection.

Aging Effects: The aging effect addressed by the Buried Pipe Inspection is a loss of material due to corrosion of the external surfaces of pipe caused by loss of the protective coating.

Method: Visual inspection of the protective coating will be performed.

Sample Size: When underground piping is uncovered during plant maintenance or modification activities, inspection of the protective coating will be performed. Sampling of underground pipe would become warranted if observations of defective protective coatings or losses of material on external surfaces of piping were seen during inspections.

Industry Code or Standards: Not applicable.

Frequency: Inspections will be performed when plant maintenance or modifications uncover buried piping. If defective protective coatings or loss of material is observed, then the frequency will be evaluated.

Acceptance Criteria or Standard: Acceptance criteria will be defined in plant procedures. The extent of the defective coatings or corrosion on the external surfaces of piping will determine the nature of the corrective action.

Timing of New Program or Activity: This inspection will be initiated prior to the end of the initial 40-year license term.

Demonstration: The Buried Pipe Inspection will be effective in the future for managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. The implementation of the new Buried Pipe Inspection provides reasonable assurance that the effects of aging will be adequately managed so that the components within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2 ELECTRICAL COMPONENT INSPECTION

Purpose: The Electrical Component Inspection Program will inspect splices, connectors, and cables located in areas that may be conducive to accelerated aging.

Scope: The scope of this inspection includes cables exposed to elevated temperatures, wet environments, or corrosive chemicals. The scope also includes cables that can experience elevated temperatures due to the current they are carrying and connectors used in impedance-sensitive circuits and cable splices subject to aging-related stressors.

Aging Effect: The aging effect for cables and cable splices is change of material properties as evidenced by cracking or discoloration of the insulation. The aging effect for connectors in impedance-sensitive circuits is corrosion of connector pins.

Method: Visual inspection will be used to detect aging effects in the cables, splices, and connectors in the scope of this program.

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 or Standards: Not applicable.

Frequency: Cables, splices, and connectors in the selected sample will be inspected at least once every 10 years.

Acceptance Criteria or Standard: No unacceptable visual indications of age related degradation of the cables, splices, and connectors in scope.

Timing of New Program or Activity: The Electrical Component Inspection Program will be formally implemented and the first inspection of in-scope cables, splices, and connectors completed prior to the expiration of the initial 40-year licensing term.

Demonstration: The Electrical Component Inspection will be effective in the future for managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. The implementation of the new Electrical Component Inspection provides reasonable assurance that the effects of aging will be adequately managed so that the components within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.3 HEAT EXCHANGER MONITORING

Purpose: The Heat Exchanger Monitoring Program will inspect heat exchangers to the extent required to ensure seismic qualification is maintained.

Scope: The Heat Exchanger Monitoring Program manages aging effects on the following ANO-1 safety-related systems and components:

Service Water System

Reactor building coolers

Emergency diesel generator jacket cooling water heat exchangers

Make-up pump lube oil coolers

Make-up pump room coolers

Decay heat room coolers

Decay heat system heat exchangers

Electrical room chillers and coolers

Control Room Ventilation System

Control room chillers and coolers

Emergency Feedwater System

Emergency feedwater system lube oil coolers

Aging Effects: The aging effects addressed by the Heat Exchanger Monitoring Program are cracking and loss of material that could result in degradation in the seismic qualification of the heat exchangers.

Method: Non-destructive examinations, such as eddy-current inspections or visual inspections, will be performed.

Sample Size: An appropriate sample population of heat exchangers will be determined based on operating experience prior to the inspections.

Industry Codes or Standards: Not applicable.

Frequency: Inspections will be performed periodically at a frequency to be determined prior to implementation.

Acceptance Criteria or Standard: No unacceptable indication of loss of material or cracking as determined by engineering analysis.

Timing of New Program or Activity: Inspection will be initiated prior to the end of the initial 40-year license term for ANO-1.

Demonstration: The Heat Exchanger Monitoring activity will be effective in the future for managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. The implementation of the new Heat Exchanger Monitoring activity provides reasonable assurance that the effects of aging will be adequately managed so that the systems within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.4 PRESSURIZER EXAMINATIONS

Section 2.3.1 of the ANO-1 LRA identifies the pressurizer as subject to aging management review. Section 3.2 of the ANO-1 LRA and BAW-2244A [Reference B-3] identify the aging effects that will require new or additional inspections for license renewal. These aging effects are cracking of pressurizer cladding, including items attached to the cladding (e.g., tripod legs), which may result in cracking or loss of underlying ferritic steel; cracking of the structural welds that connect the heater sheaths to the diaphragm plates; and cracking of small bore nozzles and safe-ends.

Management of aging effects for the pressurizer Alloy-600 small bore nozzles is addressed in the Alloy-600 Aging Management Program. Small bore safe ends are addressed in the Small Bore Piping and Small Bore Nozzle Inspections. The Pressurizer Examinations include the pressurizer cladding examination, and the pressurizer heater penetration weld examination, which are described in the following sections.

3.4.1 Pressurizer Cladding Examination

Purpose: The pressurizer cladding examination will assess the condition of the pressurizer cladding.

Scope: The scope of this activity will include the cladding and attachment welds to the cladding of the ANO-1 pressurizer.

Aging Effects: The aging effect is cracking of cladding by thermal fatigue, which may propagate to the underlying ferritic steel.

Method: Volumetric examination of the pressurizer items that are most susceptible to thermal fatigue will provide assurance that cracking of cladding has not extended into the base metal of the pressurizer. Pressurizer items with the highest cumulative usage factor include the circumferential weld that connects the shell to the lower head and the full penetration weld that connects the pressurizer surge nozzle to the lower head.

In accordance with ASME Section XI, Examination Category B-B, volumetric examination of the circumferential shell-to-head weld is performed each inspection interval. In addition, 1 ft of the longitudinal weld adjacent to the heater belt forging is volumetrically examined. The weld that connects the surge nozzle to the lower head receives volumetric examination each inspection interval in accordance with Examination Category B-D. Continuation of these inspections during the period of extended operation will manage any cracking of cladding that may extend into the base metal at the locations that are most susceptible to thermal fatigue.

Sample Size: The pressurizer design report was reviewed and the stainless steel clad carbon steel items with the highest cumulative usage factors include the circumferential weld that connects the shell to the lower head and the weld that connects the surge nozzle to the lower head. Inspection of these items will bound the remaining stainless steel clad carbon steel items in the pressurizer.

Industry Code or Standards: ASME Section XI, 1992 Edition with portions of the 1993 Addenda, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 10CFR50.55a).

Frequency: The examination frequency is defined by ASME Section XI, Table IWB-2500-1, Examination Categories B-B and B-D.

Acceptance Criteria or Standard: Acceptance standards for volumetric examination in accordance with ASME Section XI, IWB-3510 and IWB-3512.

Timing of New Program or Activity: The inspections discussed above are included in the current ANO-1 ISI program and will be carried forward to the period of extended operation.

Demonstration: As a result of pressurizer cladding cracking that occurred at Haddam Neck, cracking of cladding in the pressurizer was evaluated as a potential aging effect requiring aging management. The concern is that cracks in the cladding may extend into the underlying ferritic steel and subsequent growth of the crack may propagate and remain undetected. Based on differences in design, fabrication, and operation, cladding cracking and propagating into the ferritic base material in the ANO-1 pressurizer is not expected.

The Pressurizer Cladding Examination includes multiple volumetric examinations of pressurizer items having the highest fatigue usage factors. Any cracking of the cladding that extends into the base metal would be detected by ASME Section XI volumetric examinations at these locations. The multiple volumetric inspections being performed in accordance with ASME Section XI requirements conservatively envelope the one time inspection recommended in the SER in BAW-2244A. The Pressurizer Cladding Examination will provide reasonable assurance that the aging effects associated with the cladding and ferritic base material will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.4.2 Pressurizer Heater Bundle Penetration Welds Examination

Purpose: The pressurizer heater bundle penetration welds examination will assess the condition of the pressurizer heater penetration welds.

Scope: This examination will be applicable to the heater sheath-to-diaphragm plate penetration welds inside the pressurizer. The pressurizer contains three heater bundles.

Aging Effects: The aging effect is cracking at the heater bundle penetration welds, which may lead to reactor coolant leakage.

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

In addition, ANO-1 inspects the exterior portions of the heater bundle each outage in accordance with Examination Category B-P of ASME Section XI. In accordance with IWA-5242 as modified by Code Case N-533 for bolted connections, ANO-1 will remove the insulation surrounding the penetrations and perform a VT-1 inspection. This addresses Open Item 2 in the NRC SER of BAW-2244A.

Sample Size: The examination will include sixteen peripheral heater penetration welds on one heater bundle. However, if the surface examination of the Oconee heater bundle penetration welds is performed before the ANO-1 bundle removal and indicates that cracking of the welds is not an aging effect, the heater bundle penetration welds at ANO-1 will not be inspected. The Oconee (Units 2 and 3) and ANO-1 heater bundle designs are identical, and inspection of the Oconee Unit 1 welds would bound ANO-1 since the Oconee Unit 1 welds are fabricated from Alloy 82/182 [BAW-2244A].

Industry Code or Standards: ASME Section XI, 1992 Edition, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 10CFR50.55a).

Frequency: Pressurizer heater bundle penetration welds examination is a one-time inspection. If the results of the inspection are not acceptable, then the results may be used as a baseline inspection for establishing further programmatic actions covering the other two ANO-1 heater bundles.

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

Timing of New Program or Activity: The heater bundle examination may occur prior to entering the period of extended operation or during the period of extended operation. If the Oconee inspection occurs prior to the ANO-1 bundle removal and indicates that cracking of the heater penetration welds is an aging effect, the examination will be performed upon removal of an ANO-1 pressurizer heater bundle.

Operating Experience and Demonstration: No stainless steel heater sheath-to-diaphragm plate penetration welds have cracked to date on a B&W plant. Failures have occurred at other non-B&W plants on similar heater penetrations. However, these failures occurred on more susceptible Alloy-600 penetrations through hemispherical heads. The ANO-1 heaters are welded to a flat plate. Cracking is not expected on the ANO-1 pressurizer heaters during the period of extended operation. If through-wall cracking occurs, the resulting leakage will be detected by Leakage Detection in Reactor Building or ASME Section XI-IWB Inspection Programs. Because of the design of the heater sheath assembly, if leakage occurs, it will not be a safety concern. The mechanical design of the heater will limit leakage and provide adequate structural support even with a failure of the sheath-to-diaphragm welds. If a heater bundle is removed for replacement, surface examinations of the 16 peripheral heater penetrations and VT-3 or equivalent examinations of the remaining welds of the heater bundle will determine if cracking of these welds is an applicable aging effect. This will provide reasonable assurance that the aging effects associated with stainless steel heater penetration welds will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.5 REACTOR VESSEL INTERNALS AGING MANAGEMENT

The establishment of the ANO-1 Reactor Vessel Internals Aging Management Program involves the combination of several activities culminating in the inspection of the ANO-1 reactor vessel internals once during the 20-year period of extended operation. Ongoing industry efforts are aimed at characterizing the aging effects associated with the reactor vessel internals. As described in BAW-2248A, [Reference B-4] aging effects were qualitatively assessed based on operating conditions and operating experience. Further understanding of these aging effects will be developed by the industry over time and will provide additional bases for the inspections under this program. The purpose of the ANO-1 Reactor Vessel Internals Inspection is to provide visual inspections and non-destructive examinations of the ANO-1 reactor vessel internals during the period of extended operation. The major activities associated with this program include participation in industry activities, reporting results to the NRC, and performance of inspections.

Entergy Operations will participate in the BWOG Reactor Vessel Internals Aging Management Program and other industry programs, as appropriate, to continue investigation of aging effects for the reactor vessel internals. These activities will assist in establishing the appropriate monitoring and inspection programs for the reactor vessel internals.

Entergy Operations will provide updates after the completion of significant milestones in the preparation of the ANO-1 Reactor Vessel Internals Inspection, commencing within one year of the issuance of the renewed license. Entergy Operations will submit a report to the NRC at, or about, the end of the initial 40-year operating license term. This report will summarize the understanding of aging effects applicable to the reactor vessel internals and will contain the Entergy Operations inspection plan including methods for each inspection.

Entergy Operations will perform the ANO-1 Reactor Vessel Internals Inspection as provided in the following summary description. Should data or evaluations indicate that this inspection can be modified or eliminated, Entergy Operations will provide plant-specific justification to demonstrate the basis for the modification or elimination.

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

Scope: The inspection applies to the reactor vessel internals stainless steel items for ANO-1. These items can be separated into three groups- (1) items comprised of plates, forgings, welds, core barrel bolts, and thermal shield bolts; (2) baffle bolts and; (3) items fabricated from CASS and martensitic steel. More specifically, the items fabricated from CASS and martensitic steel include control rod guide tube spacers, vent valve bodies, 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 aging effects for plates, forgings, welds, core barrel bolts, and thermal shield are cracking due to stress corrosion and irradiation assisted stress corrosion, reduction of fracture toughness due to irradiation embrittlement, dimensional changes due to void swelling, and loss of bolted closure integrity due to stress relaxation.

The 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 aging effects for items 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 plates, forgings, welds, core barrel bolts, and thermal shield bolts. 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.

For items fabricated from CASS and martensitic steel, reduction of fracture toughness cannot be measured through traditional in-situ examination techniques, thus necessitating an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items. The specific inspection method will depend on the results of these analyses.

Sample Size: The sample size for the inspection of ANO-1 will be determined as part of the development of the inspection method.

Industry Codes or Standards: Not applicable.

Frequency: The Reactor Vessel Internals Inspection will be performed once during the twenty-year period of extended operation.

Acceptance Criteria or Standard: For plates, forgings, welds, core barrel bolts, and thermal shield bolts that will be visually inspected, critical crack size will be determined by analysis. Acceptance criteria 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 items fabricated from CASS and martensitic steel, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be determined prior to the inspection.

Timing of New Program or Activity: This inspection will begin during the period of extended operation.

Demonstration: Current plans are to perform a visual inspection of the plates, forgings, welds, core barrel bolts, and thermal shield bolts and to perform a volumetric inspection of the baffle bolts. ANO will participate in the BWOG Reactor Vessel Internals Aging Management Program and other industry programs as necessary. ANO will also participate in industry studies establishing appropriate monitoring and inspection programs for reactor vessel internals items. The final inspection program will provide reasonable assurance that the aging effects associated with the reactor vessel internals will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.6 SPENT FUEL POOL MONITORING

Purpose: The purpose of the Spent Fuel Pool Monitoring Program will be to manage the aging effects requiring management of the ANO-1 spent fuel pool liner.

Scope: The scope of the Spent Fuel Pool Monitoring Program is concerned with the ANO-1 spent fuel pool liner.

Aging Effects: Stress corrosion cracking is possible from the external surface of the liner in weld heat-affected zones since this was not verified to be chloride free during construction.

Method: The spent fuel pool monitoring trench drains will be monitored to detect liner leakage. This will identify through-wall cracks existing in the spent fuel pool liner. During this test, trench drain valves will be opened, drained, and monitored.

Sample Size: Not applicable

Industry Code or Standards: Not applicable.

Frequency: Spent fuel pool leakage to the monitoring trench drains will be monitored quarterly.

Acceptance Criteria or Standard: No unacceptable leakage due to age-related degradation of the spent fuel pool liner.

Timing of New Program or Activity: This program will be initiated before the end of the initial 40-year license term.

Demonstration: The ANO-1 history of successful operation demonstrates that leakage monitoring and inspections have been effective in managing the effects of aging on components. This is indicative that the Spent Fuel Pool Monitoring activity will be effective in the future for managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. Based on this experience, the implementation of the new Spent Fuel Pool Monitoring activity provides reasonable assurance that the effects of aging will be adequately managed so that the components within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.7 WALL THINNING INSPECTION

Purpose: Wall Thinning Inspections will be performed to ensure wall thickness is above the minimum required in order to avoid leaks or failures under normal conditions and postulated transient and accident conditions, including seismic events.

Scope: Wall Thinning Inspections cover the following safety-related systems and components:

Emergency Feedwater System

- Emergency feedwater pump casing and carbon steel discharge piping and valves
- Emergency feedwater steam supply components downstream of steam admission valves
- Emergency feedwater steam exhaust piping and valves
- Carbon steel cooling water, seal water, and instrument piping and valves
- Turbine lube oil cooler
- Carbon steel emergency feedwater supply header piping and valves (condensate supply)

Chemical Addition System

- NaOH Tank

Main Steam System

- Carbon steel piping and components

Reactor Building Isolation

- Carbon steel components of penetrations 11, 42, 43, 48, 49, 52, 54, 58, 60, 62, and 64
- Carbon steel components of penetrations 51 and 59 (chilled water system)

Aging Effects: The aging effect to be addressed by Wall Thinning Inspection is a loss of material due to corrosion of the internal surfaces of carbon steel piping and components.

Method: Non-destructive examinations, will be performed on susceptible component locations.

Sample Size: An appropriate sample size will be determined based on operating experience prior to these inspection activities.

Industry Codes or Standards: Components will be inspected in accordance with the applicable code for each respective system.

Frequency: Inspections will be performed periodically at a frequency to be determined prior to implementation. The frequency of inspections will depend upon results of previous inspections, calculated rate of material loss, and industry and plant operating experience.

Acceptance Criteria or Standard: Wall thickness measurements greater than minimum wall thickness values for the components design code of record will be acceptable.

Timing of New Program or Activity: This inspection will be initiated prior to the end of the initial 40-year license term for ANO-1.

Demonstration: The ANO-1 history of successful operation demonstrates that visual inspections have been effective in managing the effects of aging on components. This is indicative that the Wall Thinning Inspection activity will be effective in the future for managing aging effects since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. Based on this experience, the implementation of the new Wall Thinning Inspection activity provides reasonable assurance that the effects of aging will be adequately managed so that the components within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.0 EXISTING ACTIVITIES

4.1 ALLOY-600 AGING MANAGEMENT

Purpose: The ANO-1 Alloy-600 Aging Management Program will manage cracking by PWSCC of Alloy-600 and Alloy 82/182 locations for the period of extended operation.

Scope: The Alloy-600 Aging Management Program will be applicable to the Alloy-600 items and Alloy 82/182 weld material in the RCS, including the hot leg flow meter element. The scope does not include the Alloy-600 OTSG tubes, which are addressed separately in the Steam Generator Integrity Program.

Aging Effects: The aging effect managed by the Alloy-600 Aging Management Program is cracking due to primary water stress corrosion of Alloy-600 items and Alloy 82/182 weld metal in the ANO-1 RCS.

Method: ANO-1 has implemented an augmented inspection program for Alloy-600 nozzles attached to the pressurizer. The augmented inspection program consists of visual examination (i.e., VT-2) of each nozzle from the exterior of the vessel each refueling outage. In addition, on the repaired Alloy-600 level sensing nozzle, the ferritic steel in the nozzle-bore is periodically examined using ultrasonic testing. ANO-1 will continue to monitor the pressurizer Alloy-600 partial penetration welded nozzles by performing VT-2 examinations of the nozzles from the exterior of the vessel each refueling outage, during the period of extended operation

The augmented visual examination from the exterior of the vessel is sufficient to monitor the most susceptible Alloy-600 items since the industry has proven through safety evaluations that PWSCC will form axial cracks that result in RCS leakage but do not compromise the structural integrity of the pressurizer. Surface or volumetric examination of the partial penetration welded nozzles is not justified due to the inaccessibility of the welded joint (1-inch Schedule 160 pipe would have to be cut) and the demonstrated low risk associated with longitudinal cracking of these penetrations.

The pressurizer spray nozzle Alloy-600 safe end to clad carbon steel spray nozzle dissimilar metal welded joint is volumetrically inspected each interval. In addition, the welded joint that connects the spray nozzle safe end to the stainless steel spray line is volumetrically inspected each interval. Since the most probable location for cracking is at, or near, the heat-affected zone, these volumetric inspections will include the heat-affected zones. The volumetric inspections of the dissimilar metal welds associated with the spray nozzle safe end will be carried forward to the period of extended operation.

Sample Selection: From the total population of Alloy-600 items and Alloy 82/182 weld locations at ANO-1, the top three location groupings with respect to susceptibility to PWSCC will be selected for inspection. Monitoring the most susceptible locations will bound the Alloy-600 items and Alloy 82/182 weld locations that are not inspected.

The method used to perform the susceptibility ranking of the Alloy-600 items and Alloy 82/182 welds includes the following steps.

1. Identify all Alloy-600 items and Alloy 82/182 weld metal used at ANO-1

2. Select a PWSCC susceptibility model

   The model used to rank the susceptibility of Alloy-600 items and Alloy 82/182 welds to PWSCC is similar to the CRDM Nozzle PWSCC Inspection and Repair Strategic Evaluation (CIRSE) model that was applied to the CRDM penetrations [See section 2.3.3 and Appendix B of Reference B-9]. Use of a concordant method ensures consistency between the Alloy-600 Aging Management Program and the CRDM nozzle and Other Vessel Head Penetration Inspection Program, which are two separate but related programs at ANO-1.

3. Select a reference Alloy-600 item for calculation of relative time to crack initiation.

   The reference item chosen for calculation of relative time to crack initiation is the ANO-1 pressurizer instrumentation nozzle that was identified as leaking in 1990.

4. Evaluate the differences in material and operating parameters between the reference Alloy-600 part and the remaining Alloy-600 items and Alloy 82/182 welds.

   The specific material and operational parameters that were compared include maximum inside surface stress, operating temperature, microstructure, surface condition, and water chemistry.

5. Calculate the relative susceptibility factor for the Alloy-600 items and Alloy 82/182 welds relative to the time of crack initiation for the reference Alloy-600 item.

The differences in material and operational parameters were used to calculate a relative susceptibility factor, which is described in Appendix B to BAW-2301 [Reference B-9], for each Alloy-600 item and Alloy 82/182 weld. The relative susceptibility factors were used to calculate an estimated time to crack initiation for a specific Alloy-600 part or Alloy 82/182 weld relative to the time of crack initiation for the reference part. The susceptibility study was completed as a BWOG project and is described in site documentation.

Three most susceptible location groupings include (1) pressurizer sample nozzles, level tap nozzles, and thermowell nozzles; (2) pressurizer vent nozzle; and (3) the 4-inch NPS Alloy-600 safe end that connects the stainless steel spray line to the stainless steel clad carbon steel spray nozzle. Groups 1 and 2 may be combined since all of these nozzles are fabricated from Alloy-600 and are attached to the pressurizer using partial penetration welds.

The augmented inspections on the three most susceptible groupings will be carried forward to the period of extended operation. Additional inspection locations may be added based on the results of visual examinations and may be based on a qualitative assessment of risk.

The CRDM penetrations at ANO-1 are not among the top three Alloy-600 groupings with respect to susceptibility to PWSCC. For a description of the program to manage PWSCC of CRDM penetrations, see the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program, which is a separate program to address ANO-1 commitments to NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations."

Validation of Sample

At present, the B&W operating plants have experienced only two instances (other than OTSG tubes) of cracking by PWSCC: the ANO-1 pressurizer level nozzle and the CRDM nozzle at Oconee Unit 2. The model described above was used to benchmark the events at the two B&W operating plants and the predicted time to crack initiation was within a factor of 2 of the actual time to crack discovery. While the uncertainty may be high, ranking of items using the relative susceptibility factors described above provides a quantitative means of selecting candidate items for inspection.

Industry Code or Standards: ASME Section XI, 1992 Edition, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 1989 Addenda).

Frequency: Visual inspection (VT-2) of each Alloy-600 penetration (i.e., all Group 1 and 2 locations) attached to the pressurizer will be conducted each refueling outage. Volumetric inspection of the welded joints that connect the pressurizer spray nozzle safe end to the spray nozzle and stainless steel spray line will be conducted each inspection interval in accordance with ASME Section XI. In addition, on the repaired Alloy-600 level sensing nozzle, the ferritic steel in the nozzle-bore will be examined every other refueling outage using ultrasonic testing. The purpose of the inspection is to ensure that erosion/corrosion of the exposed ferritic steel in the nozzle-bore annulus is not an active damage mechanism. ANO-1 may eliminate or change the frequency of the ultrasonic testing examination should future examinations indicate that erosion/corrosion is inactive.

Acceptance Criteria or Standard: Acceptance criteria for identified flaws are in accordance with ASME Section XI.

Regulatory Basis: BAW-2243A [Reference B-5] and BAW-2244A [Reference B-3], Action Item 5.

Operating Experience and Demonstration: In 1990, a pressurizer Alloy 600 level sensing nozzle at ANO-1 developed a through-wall axial crack in the nozzle near the heat-affected zone of the J weld on the inside diameter of the vessel. The failure was due to primary water stress corrosion cracking. The crack was identified by audible indications and a dye penetrant inspection. Evaluations concluded that the crack did not compromise the structural integrity of the pressurizer. Several through-wall axial cracks have occurred in Alloy 600 nozzles throughout the industry. These cracks are small and axial due to the self-limiting high hoop stress caused by weld shrinkage during the nozzle installation process. Nozzle ejection will not occur on these type nozzle failures since the cracks are not circumferential. ANO and industry experience has proven that the visual inspection method used in this program is able to identify small leaks resulting from aging effects. In almost all leaks discovered to date, no corrosion or erosion was observed on the vessels or piping base metal. Only limited corrosion/erosion has ever been observed on the base material of a few penetrations. Conservative corrosion testing and analysis have further shown that only minimal corrosion/erosion could occur on the carbon steel base metal of the vessel or piping during one fuel cycle of operation in the event of a through wall crack. Such leaks from Alloy 600 items or Alloy 82/182 weld material will not cause sufficient loss of material to threaten the structural integrity of the vessel or piping. Based on operating experience in conjunction with analyses and testing, the Alloy 600 Aging Management Program provides reasonable assurance that the aging effects associated with Alloy 600 items and Alloy 82/182 weld material will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.2 ALTERNATE AC DIESEL GENERATOR TESTING AND INSPECTIONS

Purpose: The purpose of the Alternate AC Diesel Generator Testing and Inspections is to ensure that the effects of aging are managed before the loss of the intended functions of the system.

Scope: The Alternate AC Diesel Generator Testing and Inspections applies to the Alternate AC diesel generator and its components, as well as the fuel oil heat exchanger.

Aging Effects: The aging effects addressed by the Alternate AC Diesel Generator Testing and Inspections include the following.

- Loss of material or loss of mechanical closure integrity for the starting air subsystem components
- Loss of material or loss of mechanical closure integrity for the intake combustion air subsystem components
- Loss of material, fouling, and loss of mechanical closure integrity for the intake air aftercooler
- Loss of material for carbon steel components, cracking of the stainless steel components or loss of mechanical closure integrity for the exhaust subsystem components
- Loss of mechanical closure integrity for the lube oil subsystem components; fouling, loss of material from wear, and loss of mechanical closure integrity for the lube oil cooler
- Loss of material and loss of mechanical closure integrity for the cooling water subsystem components; fouling and a loss of material for the AAC radiator
- Loss of material from wetted portions of the exhaust fan housings
- Fouling of the fuel oil heat exchanger

Method: The Alternate AC Diesel Generator Testing and Inspections are a series of proceduralized surveillance activities. The AAC generator is started for quarterly operability testing and once every 18 months to verify the ability to satisfy station blackout requirements. The quarterly testing verifies operability by starting and slowly increasing the load on the AAC diesel.

The entire AAC diesel generator assembly is verified by this testing to be able to perform its intended function of starting and supplying power. This testing is performed in accordance with ANO commitments to the station blackout rule. This testing provides one method for managing the aging effects listed above since both pressure boundary integrity and heat transfer functions are verified by the operation of the diesel.

Inspections are periodically performed in accordance with the manufacturer's recommendations for this class of standby service of the engine and its supporting subsystems. This provides a second method for managing the aging effects listed above since the inspections and preventive maintenance could detect loss of material, leakage and fouling.

Industry Codes or Standards: Not applicable

Frequency: The AAC diesel generator is tested quarterly and once every 18 months in accordance with ANO commitments to station blackout requirements. Inspections are periodically performed in accordance with the manufacturer's recommendations for this class of standby service.

Acceptance Criteria or Standard: Acceptance criteria are based on guidance provided in the site procedures and vendor manuals.

Regulatory Basis: Responses [Reference B-10 and B-11] to Regulatory Guide 1.155, *Station Blackout,* provide a regulatory basis for these activities.

Operating Experience and Demonstration: A review of ANO-1 condition report summaries identified a loss of mechanical closure integrity on the lube oil supply header, an air leak from the starting air system, and a leak from the fuel oil day tank. These conditions identified through system testing and inspections are typical of those expected to result from the effects of aging. The continued implementation of the Alternate AC Diesel Generator Testing and Inspections provides reasonable assurance that the aging effects will be managed on these various system components so that they will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3 ASME Section XI Inservice Inspection

4.3.1 IWB Inspections

Section 2.3.1 of the ANO-1 LRA identifies the Reactor Coolant System components subject to aging management review. Section 3.2 identifies cracking, loss of material and loss of closure integrity as aging effects requiring management for these components. ASME Section XI, 1992 Edition with portions of the 1993 Addenda for pressure testing, Subsection IWB Inspections, under the ANO-1 Inservice Inspection Plan, will manage these aging effects for the period of extended operation. The specific reactor coolant system component or component feature, aging effect requiring management, and credited ASME Section XI examination category are identified in Table 3.2-1. The ASME Section XI Inservice Inspection Program, IWB Inspections, has the following attributes.

Purpose: The purpose of the ASME Section XI, Subsection IWB Inspections under the scope of the ANO-1 Inservice Inspection Plan is to identify and correct degradation of ASME Class 1 pressure retaining components and their integral attachments in accordance with 10CFR50.55a and ANO-1 Technical Specification 4.0.5.

Scope: The scope of the ASME Section XI, Subsection IWB Inspections, credited for license renewal, is identified specifically for each component and for applicable component features in Table 3.2-1. Items listed in Table 3.2-1 selected for inservice inspection at ANO-1 are consistent with the items contained in ASME Section XI, Table IWB-2500-1, with the exception of RCS piping and approved alternatives.

ANO-1 has adopted Code Case N-481 from Regulatory Guide 1.147. In addition to N-481, which requires a VT-3 visual examination of the internal surfaces whenever a pump is disassembled for maintenance, if an RCP has not been disassembled for maintenance, ANO-1 will disassemble an RCP and do a VT-3 visual inspection of the internal surface of one pump casing before entering the period of extended operations.

ANO-1 has implemented a risk-informed methodology to select RCS piping welds for inspection in lieu of the requirements specified in the 1992 Edition of ASME Section XI, Table IWB-2500-1, Examination Category B-J. The risk-informed approach is based on Code Case N-560 and consists of the following two essential elements: (1) a degradation mechanism evaluation is performed to assess the failure potential of the piping system under consideration, and (2) a consequence evaluation is performed to assess the impact on plant safety in the event of a piping failure.

The results from these two independent evaluations are coupled to determine the risk-significance of piping segments within the system and are used to prioritize the selection of welds for inspection. The results of the ANO-1 implementation of risk-informed inspection based on Code Case N-560 are reported in Reference B-7 [Correspondence 1CAN069804, June 3, 1998, Arkansas Nuclear One-Unit 1, Docket No. 50-313, License No. DPR-51, Risk Informed Inservice Inspection Pilot Plant Submittal]. In the NRC SER of the ANO-1 submittal [Letter from the NRC to Mr. C. Randy

Hutchinson entitled "Risk-Informed Alternative to Certain Requirements of ASME Code Section XI, Table IWB-2500-1 at Arkansas Nuclear One, Unit 1 (TACMA2023)," August 25, 1999, Docket No. 50-313], the staff states that the alternative method described by ANO-1 provides equivalent, or better, examination criteria for Class 1 Category B-J welds than that provided by the current Section XI requirements (i.e., 1992 Edition which is equivalent to the 1989 Edition for B-J welds).

The risk-informed process used to select piping elements for inspection is consistent with the method used to identify applicable aging effects in BAW-2243A for stainless steel piping, Alloy-600 branch connections and piping, and clad carbon steel piping. Therefore, the risk-informed method that supercedes the current Examination Category B-J requirements is appropriate for the period of extended operation and adequately addresses the applicable aging effect of cracking at welded joints for clad carbon steel and stainless steel piping. See the ANO-1 program entitled "Small Bore Piping and Small Bore Nozzles Inspections," for a discussion of the application of risk-based inspection to small bore piping (i.e., NPS less than 4 inches) and small bore nozzles. Aging management for Alloy-600 items is addressed by the ANO-1 program entitled "Alloy-600 Aging Management Program."

Aging Effects: The aging effects managed as part of the ASME Section XI, Subsection IWB Inspections include cracking, loss of mechanical closure integrity at bolted connections, and loss of material.

Method: Detection of flaws is performed using nondestructive examination techniques. Three different types of examinations are performed: volumetric, surface, and visual examinations. Volumetric examinations are the most extensive, using methods such as radiographic, ultrasonic or eddy current examinations to locate surface and subsurface flaws. Surface examinations use methodologies such as magnetic particle or dye penetrant testing to locate surface flaws.

Three levels of visual examinations are specified. The VT-1 visual examination is conducted to assess the condition of the surface of the part being examined, looking for cracks, symptoms of wear, corrosion, erosion or physical damage. It can be done with either direct visual observation or with remote examination using various optical/video devices. The VT-2 examination is conducted specifically to locate evidence of leakage from pressure retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations are conducted to detect direct or indirect indication of leakage. The VT-3 examination is conducted to determine the general mechanical and structural condition of components and supports and to detect discontinuities and imperfections such as loss of integrity at bolted connections.

Industry Code or Standards: The ASME B&PV Code Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program. For examination category B-J, the risk-informed approach is based on code case N-560.

Frequency: The frequency of inspections is specified in ASME Section XI Tables IWB-2500-1 for applicable examination categories identified in Table 3.2-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI, Tables IWB-2500-1 for all applicable examination categories identified in Table 3.2-1.

Timing of New Program or Activity: An RCP will be disassembled and inspected prior to the end of the initial 40-year license term for ANO-1.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME Section XI Code. ANO-1 Technical Specification 4.0.5 specifically requires ISI per the ASME Section XI Code. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1,* also provides a regulatory basis for this program.

Operating Experience and Demonstration: The IWB inspections are implemented in accordance with NRC approved versions of ASME Section XI using proven techniques and methods to detect and evaluate flaws. Repairs or replacement are accomplished in accordance with ASME Section XI standards. The continued implementation of the IWB Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3.2 IWC Inspections

Purpose: The purpose of the ASME Section XI, Subsection IWC inspections is to identify and correct degradation of ASME Class 2 pressure retaining components and their integral attachments in accordance with 10CFR50.55a and ANO-1 Technical Specification 4.0.5.

Scope: The scope of the ASME Section XI, Subsection IWC Inspections, credited for license renewal, includes inspection of selected components in the following systems.

- Core Flood
- Reactor Building Spray
- Main Feedwater
- Spent Fuel
- Service Water
- High Pressure Injection/Makeup and Purification
- Low Pressure Injection/Decay Heat
- Emergency Feedwater
- Main Steam
- Reactor Building Isolation
- Chilled Water System

Aging Effects: The aging effects that are managed as part of the ASME Section XI, Subsection IWC Inspections include cracking, loss of mechanical closure integrity, and loss of material.

Method: Detection of flaws is performed using nondestructive examination techniques. Three different types of examinations performed are volumetric, surface, and visual examinations. Volumetric examinations consist of radiographic, ultrasonic or eddy current examinations performed to locate surface and subsurface flaws. Surface examinations use methodologies such as magnetic particle or dye penetrant testing to locate surface flaws.

Three levels of visual examinations are specified. The VT-1 visual examination is conducted to assess the condition of the surface of the part being examined, looking for cracks, symptoms of wear, corrosion, erosion or physical damage. It can be done with either direct visual observation or with remote examination using various optical/video devices. The VT-2 examination is conducted specifically to locate evidence of leakage from pressure retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations are conducted to detect direct or indirect indication of leakage. The VT-3 examination is conducted to determine the general mechanical and structural condition of components and supports and to detect discontinuities and imperfections.

Industry Code or Standards: The ASME Code Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program.

Frequency: The frequency of inspections is specified in ASME Section XI Table IWC-2500-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI, Subsection IWC.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME Code Section XI. ANO-1 Technical Specification 4.0.5 specifically requires ISI per the ASME B&PV Code, Section XI. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, also provides a regulatory basis for this program.

Operating Experience and Demonstration: The IWC inspections are implemented in accordance with NRC approved versions of ASME Section XI using proven techniques and methods to detect and evaluate flaws. Repair and replacement are accomplished in accordance with ASME Section XI standards. The continued implementation of the IWC Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3.3 IWD Inspections

Purpose: The purpose of the ASME Section XI, Subsection IWD Inspections is to identify and correct degradation of ASME Class 3 pressure-retaining components and their integral attachments in accordance with 10CFR50.55a and ANO-1 Technical Specification 4.0.5.

Scope: The scope of the ASME Section XI, Subsection IWD Inspections, credited for license renewal includes inspections of selected components in the following systems.

- Service Water
- Spent Fuel
- Main Steam
- Emergency Feedwater
- Sodium Hydroxide
- Condensate Storage

Aging Effects: The aging effects that are managed as part of the ASME Section XI, Subsection IWD Inspections include cracking, loss of mechanical closure integrity, and loss of material.

Method: Detection of flaws is performed using visual inspection techniques. Two levels of visual examinations are specified. The VT-2 examination is conducted specifically to locate evidence of leakage from pressure retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations are conducted to detect direct or indirect indication of leakage. The VT-3 examination is conducted to determine the general mechanical and structural condition of components and supports and to detect discontinuities and imperfections.

Industry Code or Standards: The ASME Code Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program.

Frequency: The frequency of inspections is specified in ASME Section XI Table IWD-2500-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI, Subsection IWD.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME B&PV Code Section XI. ANO-1 Technical Specification 4.0.5 specifically requires ISI per the ASME

B&PV Code, Section XI. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, also provides a regulatory basis for this program.

Operating Experience and Demonstration: The IWD inspections are implemented in accordance with NRC approved versions of ASME Section XI using proven techniques and methods to detect and evaluate flaws. Repair and replacement are accomplished in accordance with ASME Section XI standards. The continued implementation of the IWD Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation

4.3.4 IWE Inspections

Purpose: The purpose of the ASME Section XI, Subsection IWE Inspections is to identify and correct degradation of Class MC pressure retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments in accordance with 10CFR50.55a.

Scope: The scope of the ASME Section XI, Subsection IWE Inspections, credited for license renewal includes inspections of the reactor building liner plate.

Aging Effects: The aging effect managed as part of the ASME Section XI, Subsection IWE Inspections is a loss of material of the steel surfaces.

Method: Detection of flaws is performed using nondestructive examination techniques. Three different types of examinations performed are volumetric, surface, and visual examinations. Volumetric examinations consist of radiographic and ultrasonic examinations. Surface examinations use methodologies such as magnetic particle or dye penetrant testing to locate surface flaws.

Two levels of visual examinations are specified. The VT-1 visual examination is conducted to assess the condition of the surface of the part being examined, looking for cracks, symptoms of wear, corrosion, erosion or physical damage. It can be done with either direct visual observation or with remote examination using various optical/video devices. The VT-3 examination is conducted to determine the general mechanical and structural condition of components and supports and to detect discontinuities and imperfections.

Industry Code or Standards: The ASME B&PV Code Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program.

Frequency: The frequency of inspections is specified in ASME Section XI Table IWE-2500-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI, Subsection IWE.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME B&PV Code Section XI. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, also provides a regulatory basis for this program.

Operating Experience and Demonstration: The IWE inspections are implemented in accordance with NRC approved versions of ASME Section XI using proven techniques and methods to detect and evaluate flaws. Repair and replacement are accomplished in accordance with ASME Section XI standards. The continued implementation of the IWE

Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3.5 IWF Inspections

Purpose: The purpose of the ASME Section XI Inservice Inspection Program, IWF Inspections is to identify and correct degradation of ASME Class 1, 2, 3, or MC component supports in accordance with 10CFR50.55a and ANO-1 Technical Specification 4.0.5.

Scope: The scope of the ASME Section XI, Subsection IWF Inspections, credited for license renewal includes component supports for ASME Class 1, 2, 3, or MC components.

Aging Effects: The aging effects managed as part of ASME Section XI, Subsection IWF include cracking, loss of material, and change in material properties.

Method: Visual examinations (i.e., VT-3) are conducted to determine the general mechanical and structural condition of component supports within the scope as defined for the applicable component support type in ASME Section XI Table IWF-2500-1.

Industry Code or Standards: The ASME Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program.

Frequency: The frequency of inspections is specified in ASME Section XI Tables IWF-2500-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI, Subsection IWF-3400.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME B&PV Code Section XI. ANO-1 Technical Specification 4.0.5 specifically requires ISI per the ASME B&PV Code, Section XI. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, also provides a regulatory basis for this program.

Operating Experience and Demonstration: The IWF inspections are implemented in accordance with NRC approved versions of ASME Section XI using proven techniques and methods to detect and evaluate flaws. Repair and replacement are accomplished in accordance with ASME Section XI standards. The continued implementation of the IWF Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3.6 IWL Inspections

Purpose: To provide instructions and documentation requirements for assessing the quality and structural performance of the reactor building's post-tensioning systems and concrete surfaces.

Scope: IWL inspections are performed on the reactor building's post-tensioning systems and concrete components that are subject to an aging management review as identified in Sections 2.4 and 3.6 of the ANO-1 LRA. Items exempt from the examination requirements include inaccessible tendon end anchors and concrete surfaces.

Aging Effects: The aging effects requiring management are loss of material for tendon anchorage and cracking and change in material properties for concrete.

Method: ASME Code Section XI, Subsection IWL provides the rules and requirements for inservice examination, inservice inspection and repair of the reinforced concrete and the post-tensioning systems of Class CC components. Such inspections are performed since degradation could lead to a crack or break in tendon wires or anchorage, thereby rendering the tendon unable to maintain compressive force on the reactor building structure during an accident.

Industry Codes or Standards: ASME Code Section XI, Subsection IWL provides requirements for inservice inspection and repair or replacement activities of the post-tensioning systems of concrete reactor building.

Frequency: Tendon surveillance is currently performed at 5-year intervals. Concrete surface examinations are conducted within a year of tendon surveillance.

Acceptance Criteria of Standard: Acceptance standards are specified in IWL-3000.

Regulatory Basis: 10CFR50.55a and technical specifications.

Operating Experience and Demonstration: During the twentieth year in-service inspection performed in the latter part of 1993, signs of degradation included an observable quantity of water in one of the tendons, corrosion on a shim at the end of one tendon, and one tendon found to have slightly low ultimate strength. The corroded shim was replaced. Metallurgical analysis found that the slightly low tensile strength was an original condition from the wire mill. The surveillance findings indicated that the tendons are experiencing normal relaxation. This experience demonstrates that the IWL inspections are effective in identifying indications of potential aging effects. In addition, the tendon surveillance and concrete inspections are performed in accordance with Subsection IWL of the ASME Code. Continued implementation of this program provides reasonable assurance that aging effects will be managed so that the reactor building post-tensioning system will continue to perform its intended function in accordance with the current licensing basis during the period of extended operation.

4.3.7 Augmented Inspections

Purpose: The purpose of the ASME Section XI, Augmented Inspections is to identify and correct degradation of components outside of the jurisdiction of ASME Section XI.

Scope: As required by the ANO-1 Technical Specification 4.15, augmented periodic inspections are completed for several main feedwater and main steam system welds, not in the Class 2 piping, to support the high energy line break analysis. Augmented inspections are completed for the BWST header including the lines from the reactor building sump. Augmented inspections that will be added to the program because of ANO-1 license renewal include the following.

- A special augmented inspection on the welds of the piping wetted by the reactor building sump water
- Some supplemental inspections of the "Q" stainless piping of the main steam system
- At least a one-time inspection of the penetration 68 piping and components and the decay heat pump room drain valves to ensure the seismic qualification is maintained to manage the aging effects of loss of material and cracking
- Special inspections of penetrations 10, 47, 58 and 64 to verify that there is no cracking in these penetrations

Aging Effects: The aging effects managed by these inspections are cracking and a loss of material.

Method: The methods utilized for augmented inspections have been discussed in the previous ASME Section XI sections.

Industry Code or Standards: The ASME Code Section XI, 1992 Edition, 1993 Addenda for Pressure Testing was used to develop this program.

Frequency: The frequency of inspections is or will be specified in the Inservice Inspection Plan. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard: Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Section XI.

Timing of New Program or Activity: The new inspections will be initiated prior to the end of the initial 40-year license term for ANO-1.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME B&PV Code Section XI. ANO-1 Technical Specification 4.15 specifically requires ISI per the ASME

B&PV Code, Section XI. NRC Reg. Guide 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, also provides a regulatory basis for this program.

Operating Experience and Demonstration: Augmented Inspections use the same non-destructive examination methods that are used for Section XI inspections on Class 1, 2, and 3 structures and components. These methods have proven effective in the industry for identifying cracking and loss of material. The continued implementation of the Augmented Inspections provides reasonable assurance that the aging effects will be managed so that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.3.8 Small Bore Piping and Small Bore Nozzles Inspections

Purpose: The Small Bore Piping and Small Bore Nozzles Inspections identify aging effects on small bore piping and nozzles.

Scope: The small bore piping and small bore nozzles, within the scope of this program, are defined as reactor coolant system piping and nozzles less than 4-inch NPS that do not receive volumetric inspection in accordance with ASME Section XI. Alloy-600 small bore branch connections, small bore safe ends, and small bore nozzles are addressed by the Alloy-600 Aging Management Program.

Aging Effect: BAW-2243A and BAW-2244A identify cracking as an aging effect for small bore piping and small bore nozzles.

Method: Section 4.4.2 of BAW-2243A states that additional inspections of small bore piping may be appropriate to assure the management of potential weld cracking for the period of extended operation. Selection of additional inspection locations should be based on detailed evaluations of material susceptibility, operating environment, stress, and risk.

ANO-1 has implemented a risk-informed method to select RCS piping welds for inspection in lieu of the requirements specified in the 1992 Edition of ASME Section XI, Table IWB-2500-1, Examination Category B-J. The risk-informed approach is based on Code Case N-560 and consists of two essential elements: (1) a degradation mechanism evaluation to assess the failure potential of the piping system under consideration, and (2) a consequence evaluation to assess the impact on plant safety in the event of a piping failure.

The results from these two independent evaluations are coupled to determine the risk significance of piping segments within the system. Priority is then given to the most risk significant piping segments during the selection of RCS piping welds for inspection.

As part of the risk-informed ISI program, ANO-1 has selected for volumetric examinations, a sample population of welds in the following Class 1 small bore piping: 1½-inch pressurizer spray line, 2½-inch makeup and purification lines, 2½-inch letdown line, and 1½-inch cold leg suction drain line.

Industry Codes or Standards: ASME Code Case N-560 is the industry code used to develop this program.

Frequency: The inspection frequencies are defined in Table 1 of ASME Code Case N-560.

Acceptance Criteria or Standard: Acceptance criteria are provided in ASME Section XI IWB-3400 and IWB-3132 as provided in ASME Code Case N-560.

Regulatory Basis: The regulatory basis for the inservice inspection program is 10CFR50.55a(g), which specifically requires ISI be performed per ASME B&PV Code Section XI. ANO-1 Technical Specification 4.0.5 also provides a regulatory basis for this program.

Operating Experience and Demonstration: Following the discovery of a cracked weld in an RCS drain line in 1989, ANO-1 implemented a program to investigate the potential for cracking of other similar lines. The root cause of the cracking was determined to be a weld defect that propagated by vibrational fatigue. A document search for records of small bore pipe failures for the past 10 years at ANO-1 revealed no piping failures caused by thermal fatigue.

Vibration induced socket weld failures at ANO have occurred, almost exclusively, on small bore (2-inch NPS and under) vents and drains. Engineering personnel performed a comprehensive root cause analysis and developed a corrective action plan for the prevention of ANO-1 piping vibration failures. Several socket welds at locations of high vibration loads were reinforced. Plant changes that may introduce new vibration sources or new vents or drains are thoroughly evaluated before implementation. At ANO-1, failures of ASME Class 1 small bore pipe have been rare.

The ANO-1 risk-informed method for selecting welds for inspection incorporates the elements necessary to manage cracking of small bore piping and small bore nozzles during the period of extended operation. The inspections are implemented in accordance with NRC approved versions of ASME section XI using proven techniques and methods to detect and evaluate flaws. Repair or replacement is accomplished in accordance with ASME Section XI standards. The continued implementation of this program provides reasonable assurance that the aging effects will be managed so that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.4 Bolting and Torquing Activities

Purpose: Bolting and torquing activities performed at ANO-1 prevent degradation of bolting or identify and correct degradation of bolting.

Scope: The scope of bolting and torquing activities is pressure boundary bolting applications associated with components within the scope of license renewal and subject to aging management review. Applications include bolted flange connections for vessels (i.e., manways and inspection ports), flanged joints in piping, body-to-body joints in valves, and pressure-retaining bolting associated with pumps or valves and miscellaneous process components.

Aging Effects: The aging effects addressed by Bolting and Torquing Activities are cracking, loss of material, and loss of mechanical closure integrity.

Method: An ANO site procedure provides guidance regarding inspections and preparation of mating surfaces, threaded fasteners, and bolted joints. Instructions are provided for proper tightening of fasteners and use of wrenching devices.

Industry Code or Standards: Not applicable.

Frequency: Bolting and Torquing activities apply when performing maintenance activities that involve threaded fasteners.

Acceptance Criteria or Standard: Acceptance criteria are provided in the ANO site procedures. Typical criteria are that mating surfaces are smooth and free of major defects. Male and female threads are inspected for major defects (nicks, burrs, evidence of galling, etc.). Other criteria include proper and adequate thread engagement, no loose fasteners, and use of appropriate torque values.

Regulatory Basis: 0CAN088201, AP&L Response to IEB 82-02 – Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants [Reference B-12].

Operating Experience and Demonstration: Procedures for bolting and torquing activities at ANO-1 are based on generic industry guidance. This guidance was based on industry experience regarding bolted closures and has been proven effective in maintaining the integrity of bolted closures. Based on this information, the continued implementation of the Bolting and Torquing Activities provides reasonable assurance that the aging effects associated with bolted closures will be managed such that applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.5 BORIC ACID CORROSION PREVENTION

Purpose: The purpose of the Boric Acid Corrosion Prevention Program is to prevent corrosion damage due to leakage from the borated water systems at ANO.

Scope: The Boric Acid Corrosion Prevention Program is concerned with the RCS and other structures or components containing, or exposed to, borated water.

Aging Effects: This program is credited with monitoring the boric acid corrosion of carbon steel external surfaces exposed to leakage from borated water. Carbon steel is utilized for bolting on many of the systems that contain borated water. This program has been identified as managing the loss of material of bolting that could eventually result in a loss of mechanical closure integrity for bolted connections.

Method: In addition to RCS leakage monitoring during normal operation, ANO-1 completes visual inspections to identify pressure boundary leakage. A partial inspection of the RCS is performed during plant cooldowns (as long as the cooldown was not an emergency) to identify locations needing repair. Detailed post outage pressure testing and visual inspections of RCS components are completed to demonstrate the reactor coolant system integrity prior to the return to criticality. This inspection is utilized to identify leakage for evaluation in accordance with the Boric Acid Corrosion Prevention Program. Prior to plant startup, active leaks that contact carbon steel are repaired, redirected, or evaluated as acceptable for continued service. The implementing procedures provide guidance on the system walkdown requirements and leakage evaluation criteria.

Industry Code or Standards: Not applicable.

Frequency: Visual inspections are performed during plant cooldowns and heatups. Additional inspections may be performed based on the nature of RCS leakage detected during normal operations.

Acceptance Criteria or Standard: The acceptance criteria for the Boric Acid Corrosion Prevention Program are contained in site procedures. Evaluations are accomplished for each identified leak. Consideration is given to the possibility of flow paths from the leak to carbon steel components, or the accumulation of boric acid in insulation. Any staining or buildup of boric acid crystals is evaluated to ensure no components are damaged to the extent that they would be unable to fulfil their intended safety function.

Regulatory Basis: 0CAN058813, Entergy's response to Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants.* [Reference B-13]

Operating Experience and Demonstration: The Boric Acid Corrosion Prevention Program has been successful in ensuring the proper identification, evaluation, and repair of boric acid leakage. Leakage is being reported not only on the reactor coolant system components, but also on other systems that contain borated water. This program has helped in the reduction of unidentified reactor coolant system leakage. This experience demonstrates the success of the program in detecting and initiating corrective action for boric acid leakage. In conjunction with other programs, the continued implementation of the Boric Acid Corrosion Prevention Program provides reasonable assurance that the aging effects associated with boric acid corrosion will be managed such that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6 CHEMISTRY CONTROL

Procedures for chemistry inspections of ANO-1 systems and heat exchangers outline inspections checking for corrosion, deposits, structural damage, general cleanliness, appearance and biological growth. Chemistry inspections are frequently performed on components and systems that are available due to routine or corrective maintenance. These inspections help to verify the adequacy of the existing chemistry controls and ensure unanalyzed degradation is not occurring.

The following subsections address the individual ANO-specific chemistry control programs in more detail:

- Primary Chemistry Monitoring Program
- Secondary Chemistry Monitoring Program
- Auxiliary Systems Chemistry Monitoring
- Diesel Fuel Monitoring Program
- Service Water Chemical Control Program

4.6.1 Primary Chemistry Monitoring

Purpose: The purpose of the Primary Chemistry Monitoring Program is to maximize long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up.

Scope: The scope of the Primary Chemistry Monitoring Program, with respect to license renewal, includes sampling activities and analysis on the following systems:

- Reactor Coolant System
- Borated Water Storage Tanks
- Spent Fuel Pool System
- Letdown Purification Demineralizers
- Reactor Makeup Water

Aging Effects: The Primary Chemistry Monitoring Program provides assurance that elevated levels of contaminates and oxygen do not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

Method: The ANO-1 Primary Chemistry Monitoring Program consists of sampling criteria, frequencies, locations, and allowable values with specific guidance for parameters exceeding allowable values.

- **Industry Code or Standards:** Not applicable.

Frequency: The frequency of sampling is daily, weekly, monthly, quarterly or as required, based on plant operating conditions. This frequency has been established based on technical specification requirements, EPRI guidelines, and ANO-specific experience.

Acceptance Criteria or Standard: The acceptance criteria for the Primary Chemistry Monitoring Program are contained in site procedures and are based on the sampling parameter, the sampling location, and plant operating conditions. These criteria have been established based on technical specification requirements, EPRI guidelines, and ANO-specific experience.

Regulatory Basis: ANO-1 Technical Specification 3.1.5, Chemistry.

Operating Experience and Demonstration: Operating experience on the primary systems demonstrates the effectiveness of the Primary Water Chemistry Monitoring Program. No significant chemistry related degradation of primary components has been experienced. Experience has shown that implementation of a primary chemistry program in accordance with accepted industry standards is effective in managing the effects of aging. Based on this experience, the continued implementation of the Primary Chemistry Monitoring Program provides reasonable assurance that aging effects will be managed so that primary system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.2 Secondary Chemistry Monitoring

Purpose: The purpose of the Secondary Chemistry Monitoring Program is to maximize the availability and operating life of major components at ANO-1.

Scope: The scope of the Secondary Chemistry Monitoring Program includes sampling activities and analysis on the main feedwater system, condensate storage system, and steam generators. The aging reviews for many of the safety-related, non-Class 1 systems also indirectly credit the Secondary Chemistry Monitoring Program since the condensate storage tanks are used as a source of makeup water to these systems.

Aging Effects: Since the Secondary Water Chemistry Monitoring Program has adequate processes to ensure the levels of contaminants and oxygen are well below the assumptions of the aging management reviews, this prevents or minimizes the occurrence of loss of material and other aging effects.

Method: The ANO-1 Secondary Chemistry Monitoring Program consists of sampling parameters, frequencies, locations, and allowable values with specific guidance given when parameters exceed specified allowable ranges.

Industry Code or Standards: Not applicable.

Frequency: The frequency of sampling is daily, weekly, monthly, quarterly or as required, based on plant operating conditions. This frequency has been established based on technical specification requirements, EPRI guidelines, or ANO-specific experience.

Acceptance Criteria or Standard: The acceptance criteria for the Secondary Chemistry Monitoring Program are located in site procedures and are based on the sampling parameter, the sampling location, and the plant operating conditions. These criteria have been established based on EPRI guidelines and ANO-specific experience.

Regulatory Basis: The regulatory basis for this program includes Facility Operating License DPR-51 Section 2.c.(7).

Operating Experience and Demonstration: Operating experience with the secondary systems demonstrates the effectiveness of the Secondary Chemistry Monitoring Program. Chemistry parameters are controlled well within EPRI guidelines and industry standards. These standards have been proven, through industry experience, to be appropriate for minimizing the effects of aging on secondary system components. Based on this experience, the continued implementation of the Secondary Chemistry Monitoring Program provides reasonable assurance that aging effects will be managed so that secondary components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.3 Auxiliary Systems Chemistry Monitoring

Purpose: The purpose of the Auxiliary Systems Chemistry Monitoring Program is to maximize the availability and operating life of the components used for the closed cooling loops at ANO-1.

Scope: The scope of the Auxiliary Systems Chemistry Monitoring Program, with respect to license renewal, is limited to sampling activities and analysis on the following systems.

- Intermediate Cooling Water System
- Chilled Water Systems
- Emergency Diesel Generators
- Alternate AC Diesel Generator

Aging Effects: The Auxiliary Systems Chemistry Monitoring Program is credited with minimizing the loss of material due to corrosion, cracking, fouling, and loss of mechanical closure integrity.

Method: The water in the applicable system is sampled. Control parameters are monitored and corrective actions are taken if the parameters are outside the acceptable range. Corrosion inhibitors may be utilized in these systems.

- **Industry Code or Standards:** Not applicable.

Frequency: The frequency of sampling is established based on EPRI guidelines and ANO-specific experience.

Acceptance Criteria or Standard: The acceptance criteria for the Auxiliary Systems Chemistry Monitoring Program are located in site procedures and are based on the sampling parameter, the sampling location, and the plant operating conditions. These criteria have been established based on equipment specification requirements, EPRI guidelines, or ANO-specific experience.

Regulatory Basis: None.

Operating Experience and Demonstration: As part of the Auxiliary Systems Chemistry Monitoring Program, corrosion inhibitor levels, biological activities and corrosion rates are monitored and trended. Based on these trends, there appear to be no major corrosion mechanisms that could prevent the closed loop systems of ANO-1 from performing their intended function for many years. Corrosion inhibitor concentrations are maintained well within their effective concentrations. Biocides are added as necessary to keep biological activity within industry recommended specifications. Corrosion rates in the intermediate cooling water system are monitored with coupons and are well within EPRI guidelines for closed loop systems. During system visual inspections conducted in conjunction with maintenance activities, no deposits or visible pitting or corrosion have been observed on the ANO-1 closed-loop cooling systems. Based on this experience, continuation of the Auxiliary Systems Chemistry Monitoring Program will provide reasonable assurance that the aging effects will be managed such that the applicable structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.4 Diesel Fuel Monitoring

Purpose: The purpose of the Diesel Fuel Monitoring Program is to ensure that adequate diesel fuel quality is maintained to prevent plugging of filters, fouling of injectors, and corrosion of the fuel systems.

Scope: The scope of the Diesel Fuel Monitoring Program is limited to sampling activities and analysis on the following tanks.

- Bulk fuel oil storage tank
- Emergency diesel fuel tanks
- Emergency diesel day tanks
- Fire pump diesel day tank
- AAC diesel generator day tank

Aging Effects: The aging management reviews credit the sampling and monitoring as providing an adequate control of the fuel oil to ensure water and contamination (including microbiological) are not present in the system.

Method: The ANO-1 Diesel Fuel Monitoring Program consists of sampling parameters, frequencies, locations, and allowable values with specific guidance given when parameters exceed specified allowable ranges.

Industry Code or Standards: References used to develop this program include:

- ASTM D975-1981, Standard Specification for Diesel Fuel Oils
- VV-F-800D, Military Specifications
- Other ASTM Standards

Frequency: Monthly and quarterly samples are taken from the tanks within the scope of the program. In addition, each new shipment of diesel fuel is sampled prior to unloading into the bulk fuel oil storage tank.

Acceptance Criteria or Standard: The acceptance criteria for the Diesel Fuel Monitoring Program are contained in site procedures. These criteria have been established based on technical specification requirements or industry codes or standards.

Regulatory Basis: ANO-1 Technical Specification 4.6.1, Diesel Generators.

Operating Experience and Demonstration: Past operating experience involving diesel fuel at ANO has included problems with water in the fuel, particulate contamination, and biological fouling. Based on these experiences, a comprehensive diesel fuel monitoring program was developed at ANO. The ANO Diesel Fuel Monitoring Program was implemented to prevent the problems experienced in the past. The program provides for addition of biocides and stabilizers, as necessary, to prevent biological breakdown of diesel fuel. Procedures provide instructions for routine tank bottom draining to remove any water accumulation. Diesel tanks at ANO are cleaned at least once every 10 years to remove sediment. Diesel tank filtration provides for removal of particulate buildup. Tanks that are drained for cleaning are inspected for corrosion and other physical degradation. Tank inspections over the past years have not shown tank degradation or corrosion. The continuation of the Diesel Fuel Monitoring Program will provide reasonable assurance that the aging effects will be managed such that the diesel fuel oil system structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.5 Service Water Chemical Control

Purpose: The purpose of the Service Water Chemical Control Program is to maximize the availability and operating life of the components in the ANO-1 service water system.

Scope: The scope of the Service Water Chemical Control Program includes sampling activities and analysis on the service water system. The scope also includes chemical injection into the service water bays. The fire protection system also takes suction from the service water bays.

Aging Effects: The Service Water Chemical Control Program has been credited in the aging management reviews for the service water system, the auxiliary cooling water system, and the fire protection system since these systems draw suction from the intake structure. The chemical additions are only credited with reducing corrosion, and are not credited with elimination of this mechanism.

Method: The Service Water Chemical Control Program consists of sampling parameters, frequencies, locations, and allowable values with specific guidance given for parameters exceeding allowable values.

Industry Code or Standards: Not applicable.

Frequency: The frequency of sampling is daily, twice per week, weekly, or as required, based on plant conditions. This frequency has been established based on ANO-specific experience.

Acceptance Criteria or Standard: The acceptance criteria for the Service Water Chemical Control Program are contained in site procedures and are based on the sampling parameter, the sampling location, and the plant operating conditions. These criteria have been established based on EPRI guidelines and ANO- specific experience.

Regulatory Basis: ANO response to NRC Generic Letter 89-13 [Reference B-31, B-32, B-33, B-34, and B-35].

Operating Experience and Demonstration: The Service Water Chemical Control Program supplements the Service Water Integrity Program in managing the effects of aging on the service water and auxiliary cooling water systems. Corrosion inhibitor concentrations are monitored and maintained well within their effective concentrations. Biocide is continuously added to control biological activity. Corrosion rates of the service water system are monitored with coupons. System visual inspections are conducted when maintenance activities allow. Based on the results of these inspections, in addition to testing and inspections performed as part of the Service Water Integrity Program, system components or piping may be scheduled for replacement. Based on this experience, the continued implementation of the Service Water Chemical Control Program, in conjunction with the Service Water Integrity Program, provides reasonable assurance that the effects of aging will be adequately managed so that the service water and auxiliary cooling water components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.7 CONTROL ROD DRIVE MECHANISM NOZZLE AND OTHER VESSEL CLOSURE PENETRATION INSPECTION PROGRAM

Section 2.3.1.5 of the ANO-1 LRA and BAW-2251A identify the control rod drive mechanism nozzles and other vessel closure penetrations as subject to aging management review. Section 3.2.4 of the ANO-1 LRA and BAW-2251A [Reference B-16] identify primary water stress corrosion cracking as an aging effect of concern that must be managed for the period of extended operation. The CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program in conjunction with the Chemistry Control Program, Inservice Inspection Program, Leakage Detection in Reactor Building, and Boric Acid Corrosion Prevention Program will manage PWSCC for the period of extended operation.

Purpose: The purpose of the CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program is to verify the assumptions made in BAW-2301 [Reference B-9], BWOG Integrated Response to Generic Letter 97-01, of the susceptibility and consequence of PWSCC in B&W-designed CRDM nozzles.

Scope: The scope of the program includes the B&W-designed reactor vessel closure head CRDM nozzles and other closure head penetrations.

Aging Effects: The aging effect is PWSCC of Alloy-600 nozzles with partial penetration welds that cause high circumferential residual stresses on the inner diameter of the nozzles opposite the welds.

Method: The current BWOG program requires the re-inspection of from two to twelve Oconee Unit 2 CRDM nozzles from the top of the head and an inspection of all CRDM penetrations at Crystal River Unit-3. The Oconee Unit 2 re-inspection was completed in 1999 and no change was reported relative to previous inspections. At present, the Crystal River Unit-3 inspection is scheduled for 2001. The method used to select the most susceptible B&W-designed nozzles for inspection is described in BAW-2301, Section 2.3. The ANO-1 CRDM nozzles are among the lowest in susceptibility of the B&W operating plants with a predicted relative time to failure well in excess of 48 EFPY. In addition, the ANO-1 CRDM nozzles are ranked in the "beyond 15 year" category in the NEI integrated "Industry Histogram for Reactor Vessel Head Penetrations." ANO-1 will continue to monitor the inspection results from the B&W operating plants and other plants during the current term of operation and during the period of extended operation. The need for inspections during the period of extended operation at ANO-1 will be determined based on the results of inspections at the other B&W operating plants.

At Oconee and Crystal River Unit-3, eddy current inspection will be utilized for detection and eddy current, ultrasonic, and liquid penetrant will be used for sizing.

Industry Code or Standard: Not applicable.

Frequency: The inspection frequency is dependent on plant-specific, BWOG, and industry-wide inspection results. The inspections at Crystal River Unit-3 are planned for 2001. Plans for future inspections at specific B&W operating plants will be adjusted based upon review of ongoing inspections.

Acceptance Criteria or Standard: Should ANO-1 inspect, axial flaws detected during inspection will be analyzed and evaluated using the NUMARC acceptance criteria, which were approved by the NRC in their Safety Evaluation, dated November 19, 1993. Circumferential flaws will be analyzed and addressed with the NRC on a case-by-case basis.

Regulatory Basis: 0CAN079703 and 0CAN029908, ANO-1 responses to NRC Generic Letter 97-01. [References B-17 and B-18].

Operating Experience and Demonstration: A full inspection of Oconee Unit 2 from beneath the reactor vessel head was performed in 1994. In addition, a re-inspection was completed on two Oconee Unit 2 CRDM nozzles in 1996 from above the reactor vessel head. The results of these inspections were submitted to the NRC. A subsequent re-inspection at Oconee Unit 2 was completed in 1999.

The Oconee Unit 2 inspections in 1994 identified a small number of nozzles with crack-like indications that were insignificant in depth. Re-inspection showed no growth after one cycle of operation. Re-inspection in 1999 showed no change relative to the 1996 and 1994 inspections. Future inspections will be performed in a manner consistent with these previous inspections. Based on the above review, the continued implementation of the CRDM Nozzle and Other Vessel Closure Penetration Inspection Program provides reasonable assurance that the aging effects will be managed such that the CRDM nozzle penetrations will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8 FIRE PROTECTION

The primary objectives of ANO-1's Fire Protection Program are:

- The prevention of fire
- The prompt detection and suppression of fires , and
- The protection of systems, structures, and components essential to plant safety so that they are able to withstand a fire without a loss function.

The activities performed to achieve the Fire Protection Program objectives that are credited for the management of aging effects are:

- Fire Barrier Inspections,
- Fire Hose Station Inspections,
- Fire Suppression Water Supply System Surveillance,
- Fire Suppression Sprinkler System Surveillance,
- Fire Water Piping Thickness Evaluation,
- Control Room Halon Fire System Inspection,
- NFPA 25 Testing of Sprinkler Head Components that are 50 years old, and
- Reactor Coolant Pump Oil Collection System Visual Inspection.

4.8.1 Fire Barrier Inspections

Fire barriers subject to aging management review include fire walls/floors, fire doors/hatches, fire damper mountings, fire wraps, and fire stops. The aging effects for fire barriers are discussed in Section 3.6 of the ANO-1 LRA.

Purpose: Fire Barrier Inspections provide for periodic surveillance of fire barriers separating redundant safe shutdown systems to assure that they perform their separation functions.

Scope: The scope includes 10CFR50.48-required fire walls and fire floors as indicated on the fire protection drawings. Fire doors/hatches, fire damper mountings, fire wraps, and penetration fire stops associated with 10CFR50.48-required fire walls and/or fire floors are within the scope.

Aging Effects: The aging effects requiring management for fire barriers are as follows.

Fire walls (masonry blockwalls)	Cracking
Fire doors/hatches (including threaded fasteners)	Loss of material
Fire wraps (and associated banding)	Loss of material, cracking/ delamination, and/or change in material properties
Penetration fire stops	Loss of material, cracking/ delamination/separation, and change in material properties

There are no aging effects that require management associated with fire walls comprised of concrete (including fire floors) or with fire dampers.

Method: Fire barriers are visually inspected.

Industry Code or Standard: Not applicable.

Frequency: Fire barriers are periodically inspected as follows:

Each fire barrier: At least once per 18 months (excluding penetration seals).

Fire doors and hardware: At least once per 18 months.

Sealed penetrations: At least 10 percent of each type are inspected at least once per 18 months. If penetration is found inoperable, an additional 10 percent of the degraded type are inspected until a 10 percent sample is found with no visual degradation. Samples are selected so that each penetration seal is inspected at least once every 15 years.

Repaired fire barriers: Inspected prior to returning fire barrier to operable status.

Acceptance Criteria or Standard: Fire barriers are considered operable when the visually observed condition is the same as the as-designed condition. Acceptance criteria are indicated in the Fire Barrier Inspection procedures.

Regulatory Basis: The regulatory basis for this program is 10CFR50.48, 10CFR Part 50 Appendix R, and Operating License DPR-51 Paragraph 2.c.(8).

Operating Experience and Demonstration: The condition reporting system was utilized to review the ANO-1 operating experience pertaining to fire barriers. The review indicated that voids and gaps have been discovered at fire barrier penetration seals. Other damage to fire barriers has included torn boot seals, loose damming material from building vibration or contraction from temperature changes, and holes associated with blockwall cracks in the vicinity of penetrations. Damaged penetration seals and fire barriers have been repaired. This experience demonstrates that Fire Barrier Inspections are effective in being able to identify and initiate corrective action for fire barrier deficiencies. Based on this experience, continuation of Fire Barrier Inspections will provide reasonable assurance that the aging effects will be managed such that the fire barriers will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.2 Fire Hose Station Inspections

Purpose: The purpose of Fire Hose Station Inspections is to assure that manual fire suppression is available to safety-related equipment.

Scope: Fire hose reels associated with 10CFR50.48-required fire hose stations are within the scope of license renewal.

Aging Effects: The aging effect for fire hose reels (including threaded fasteners) is a loss of material.

Method: Fire hose reels are visually inspected.

Industry Codes or Standards: Fire hose station inspections were developed using guidance of the National Fire Protection Association.

Frequency: Fire hose reel inspections are performed once every 31 days.

Acceptance Criteria or Standard: Fire hose stations, protecting areas containing safety related equipment, are to be operable whenever the safety related equipment is required to be operable. Acceptance criteria are indicated in the fire hose station testing procedure.

Regulatory Basis: The regulatory basis for this program is 10CFR50.48, 10CFR Part 50 Appendix R, and Operating License DPR-51 Paragraph 2.c.(8).

Operating Experience and Demonstration: A review of ANO-1 condition report summaries did not identify indications of a loss of material associated with fire hose reels. Hose reels not operating properly were typically either misaligned or there were problems with their swivel connections. While these inspections have identified no applicable aging effect, visual inspections have proven effective in identifying indications typical of the applicable aging effect for fire hose reels. Continuation of Fire Hose Station Inspections will provide reasonable assurance that the aging effect will be managed such that fire hose reels will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.3 Fire Suppression Water Supply System Surveillance

Purpose: The purpose of this surveillance is to verify operability of fire suppression water supply system components.

Scope: The Fire Suppression Water Supply System Surveillance applies to ANO-1 fire water system supply piping and valves. The surveillance applies to several diesel fire pump subsystems including the intake air, exhaust, lube oil, and cooling water. Fire protection system heat exchangers are also within the scope of this surveillance.

Aging Effects: This activity verifies that loss of material due to internal surface corrosion and fouling of carbon steel, stainless steel, brass or bronze components is managed. This activity also manages cracking of stainless steel, brass, or bronze components.

Method: The following surveillance activities are performed on the fire suppression water supply system

- At least once per 31 days, on a staggered test basis, each fire water pump is started by automatic actuation and operated for 15 minutes with flow through a relief line.
- A flush of the system main is performed at least once every six months.
- A system functional test is performed at least once per 18 months, which includes simulated automatic actuation of the system throughout its operating sequence, and includes verification of pump flow, discharge pressure, and fire suppression water system pressure requirements.
- At least once per three years a flow test of the system is completed in accordance with Chapter 5, Section 11, of the Fire Protection Handbook 14th edition.

These tests ensure the pumps are capable of starting and supplying the required flow rate and ensure the heat exchangers for the fire pumps operate as required. The flushing and flow testing helps to ensure flow blockage is not present from a buildup of corrosion products or fouling.

Industry Codes or Standards: Standards and recommended practices of the National Fire Protection Association were used as guidance in the development of fire suppression water system surveillances.

Frequency: The frequency of surveillance activities is listed under the Method discussion of this program.

Acceptance Criteria or Standard: Acceptability of surveillance results is determined in accordance with site procedures.

Regulatory Basis: The regulatory basis for this program is 10CFR50.48, 10CFR Part 50 Appendix R, and operating license DPR-51 paragraph 2.c.(8).

Operating Experience and Demonstration: Inspections of the underground cement lined cast iron piping have shown negligible corrosion degradation. The above ground carbon steel pipe is inspected during repair or replacement of fire water components. There have been replacements of components and piping in the small-bore carbon steel piping due to internal corrosion. Based on this experience, these surveillance activities will continue to provide assurance that aging effects will be adequately managed so that fire protection system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.4 Fire Suppression Sprinkler System Surveillance

Purpose: The purpose of this surveillance is to provide a method for verifying operability of fire suppression sprinkler system components.

Scope: Within the scope of license renewal, the Fire Suppression Sprinkler System Surveillance applies to ANO-1 fire suppression sprinkler system piping, valves, and nozzles.

Aging Effects: This activity verifies that loss of material due to internal surface corrosion and fouling of carbon steel, stainless steel, brass or bronze components is managed. This activity also manages cracking of stainless steel, brass, or bronze components.

Method: The following surveillance activities are performed on the fire suppression sprinkler system.

- Each testable valve in the flow path is cycled at least once per 12 months. An exception for this surveillance applies to the valves in the reactor building, which shall be inspected when in cold shutdown.
- An inspection to verify the integrity of the spray nozzles and headers is performed at least once every 18 months.
- Deluge spray system flush is performed quarterly.

Industry Codes or Standards: The standards and recommended practices of the National Fire Protection Association were used as guidance in the development of the fire suppression sprinkler system surveillance.

Frequency: The frequency of surveillance activities is listed under the Method section of this program.

Acceptance Criteria or Standard: Acceptability of surveillance results is determined in accordance with site procedural instructions.

Regulatory Basis: The regulatory basis for this program is 10CFR50.48, 10CFR Part 50 Appendix R, and Operating License DPR-51 Paragraph 2.c.(8).

Operating Experience and Demonstration: Internal visual inspections of sprinkler system components are performed during maintenance activities that require the system to be opened. Inspection reports have noted general corrosion, but no severe cases. In addition to visual inspections, ultrasonic testing is performed on sprinkler piping on a regular basis. These examinations have not identified any piping that failed the initial screening process and required further evaluation. This method has proven effective on other systems in identifying wall thinning as a result of corrosion mechanisms. This experience indicates that continuation of the Fire Suppression Sprinkler System

Surveillance inspections will provide assurance that aging effects will be adequately managed so that fire protection sprinkler systems will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.5 Fire Water Piping Thickness Evaluation

Purpose: The purpose of Fire Water Piping Thickness Evaluation is to provide a method for the examination and evaluation of pipe wall thickness changes in the fire water system.

Scope: Within the scope of license renewal, the Fire Water Piping Thickness Evaluation applies to ANO-1 fire water system piping.

Aging Effects: A loss of material by internal surface corrosion of cast iron, carbon steel, or stainless steel fire water system components is the aging effect managed by the Fire Water Piping Thickness Evaluation.

Method: Minimum and nominal design wall thickness specifications are obtained prior to performing the examination. The wall thickness at the deepest pit and the average wall thickness are obtained, using non-destructive examination methods, as outlined in the fire water piping thickness evaluation procedure.

Industry Codes or Standards: Not applicable.

Frequency: Fire water piping is examined at a frequency determined by the system engineer. The frequency and locations for the inspections are based on results of previous inspections, the time since previous inspections, inspections of nearby or representative piping, and the need for additional inspection locations to characterize the condition of a pipe section. The consequences of failure of the subject piping are also considered when determining examination frequency and location.

Acceptance Criteria or Standard: Acceptability of examination results for each inspection location is determined in accordance with site procedural instructions.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: Ultrasonic thickness examinations have been performed on the fire water system. UT examinations have determined that there is loss of material due to pitting in the fire water system piping. There have been repairs to the fire water system piping due to excessive pipe wall thinning. This experience demonstrates that the Fire Water Piping Thickness Evaluation Program is able to identify loss of material and initiate corrective action. Based on this experience, these examinations will continue to provide assurance that aging effects will be adequately managed so that fire protection system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.6 Control Room Halon Fire System Inspection

Purpose: The purpose of the Control Room Halon Fire System Inspection, with respect to license renewal, is to assure that frequently manipulated components are free of aging effects.

Scope: The components within the scope of the Control Room Halon Fire System Inspection are listed in Table 3.4-6.

Aging Effects: The aging effects addressed by the Control Room Halon Fire System Inspection are loss of material due to wear from frequent manipulations and cracking.

Method: The Control Room Halon Fire System Inspection provides for periodic inspections to ensure halon system operability. Leakage in the pressurized portion of the halon system would be detected by this inspection. During these inspections, the cylinders are disconnected from the headers and are weighed.

The procedure verifies the nitrogen bottle pressure is adequate and that cracking or loss of material has not caused a leak to occur. Steps in the procedure verify the correct reinstallation. The components are visually inspected during this activity.

Industry Code or Standards: The NFPA Standard 12A was utilized in the development of this inspection program.

Frequency: Inspections are performed at least once every 6 months.

Acceptance Criteria or Standard: Acceptance standards for minimum halon cylinder weights, minimum halon and nitrogen pressures and maximum nitrogen cylinder pressures are listed in the inspection procedure.

Regulatory Basis: The regulatory basis for this program is 10CFR50.48, 10CFR Part 50 Appendix R, and Operating License DPR-51 Paragraph 2.c.(8).

Operating Experience and Demonstration: Semi-annual testing has identified several types of system degradation. Included are the loss of nitrogen or halon pressure or weight, and the perturbation of the protected enclosure halon vapor barrier. Past system halon loss has been, in part, due to removal of factory gauges to install calibrated test gauges during cylinder testing. The cylinders have been fitted with permanently installed calibrated gauges to lesson the losses of nitrogen pressure or halon during testing. Spare cylinders have been removed entirely from the testing program. In addition, nitrogen pressure or halon has been lost because of bad seals in the cylinder control heads.

The ceramic board and ceiling tile fire barriers exist to contain the halon in the control room ceiling and to provide a fire barrier between the occupied control room workspace and the protected overhead space. Semiannual inspection will ensure the identification and repair of any degradation of the barriers in the overhead. Based on this operating experience, the continued implementation of the Control Room Halon Fire System

Inspection provides reasonable assurance that the effects of aging will be adequately managed so that the system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.7 Reactor Coolant Pump Oil Collection System Inspection

Purpose: The purpose of the Reactor Coolant Pump Oil Collection System Inspection, with respect to license renewal, is to ensure integrity of the reactor coolant pump oil leakage collection system.

Scope: The scope of the Reactor Coolant Pump Oil Collection System Inspection applies to the shrouds, drip pans, dammed areas, accessible piping, collection tanks, and spray protection.

Aging Effects: The aging effects addressed by the Reactor Coolant Pump Oil Collection System Inspection are a loss of material and a loss of mechanical closure integrity. These aging effects would be caused by general corrosion of the carbon steel internal surfaces or external surfaces due to the potential for water leakage into the system.

Method: The Reactor Coolant Pump Oil Collection System Inspection is a visual inspection. Guidance for this inspection is contained in a site procedure.

Industry Code or Standards: Not applicable.

Frequency: The inspection is performed during shutdown and prior to startup for each refueling outage.

Acceptance Criteria or Standard: Acceptance criteria are based on guidance provided in site procedures. There should be no accumulation of oil outside the collection system.

Regulatory Basis: 10CFR50 Appendix R Section III.O and 0CAN049705, response to IR 96-027 [Reference B-19].

Operating Experience and Demonstration: The Reactor Coolant Pump Oil Collection System Inspection is normally performed during shutdown and prior to startup for each refueling outage. If an abnormal accumulation of oil is found or the integrity of the collection system is found deficient, corrective action will be initiated and documented per the inspection procedure. Additionally, if oil is found that is not being collected, corrective action will be initiated in accordance with the inspection procedure. Visual inspections have been effective in identifying these types of deficiencies. If any of these events occur, corrective actions will be taken to reestablish design requirements and prevent reoccurrence. Based on this review, continuation of the Reactor Coolant Pump Oil Collection System Inspection will provide reasonable assurance that the aging effects associated with the oil collection system will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.9 FLOW ACCELERATED CORROSION PREVENTION

Purpose: The purpose of the Flow Accelerated Corrosion Prevention Program is to provide a programmatic approach for identifying, inspecting, and managing loss of material for components that are adversely affected by flow accelerated corrosion (also known as erosion/corrosion).

Scope: For the systems within the scope of license renewal, only the main feedwater and main steam systems are identified as susceptible to flow-accelerated corrosion.

Aging Effects: The aging effect is a phenomenon that results in metal loss from components made of carbon steel, which occurs only under certain conditions of flow, chemistry, geometry, and material. The aging management reviews credit this program with determining which systems are susceptible to flow-accelerated corrosion and monitoring the loss of material for those systems.

Method: The Flow Accelerated Corrosion Prevention Program utilizes a combination of computer codes, previous examination results, industry experience, and engineering judgment to determine specific locations to be inspected. Ultrasonic inspections and visual inspections (where applicable) are utilized to quantify the amount of wall thinning on a component. The inspection data is documented in engineering reports that are developed for each refueling outage. Inspection information is input into the CHECWORKS Program to refine the PASS 2 analysis to predict wall thinning rates more accurately.

Per procedural requirements for developing modification packages, program-screening checklists are completed to ensure impact evaluations are accomplished for modifications affecting systems included in the flow-accelerated corrosion program. The current CHECWORKS database tracks safety and non-safety related large bore components in the main steam, main feedwater, condensate, reheat steam, extraction steam, and heater vents and drains systems.

Industry Code or Standards: Not applicable.

Frequency: Inspection frequency for each location is based on consideration of previous inspection results, CHECWORKS predictions resulting from PASS-2 analysis, changes in plant operating or chemistry conditions, and pertinent industry events.

Acceptance Criteria or Standard: The acceptance criteria for the Flow Accelerated Corrosion Prevention Program are located in site procedures. Any measured wall thickness below, or projected to be below, 70% of nominal wall at the next refueling outage is evaluated to determine if additional areas need to be examined. Any component with a measured wall thickness below, or projected to be below, the ASME B31.1 minimum wall will be replaced, unless a local wall thinning evaluation can show acceptability for continued service.

Regulatory Basis: The documents that provide the regulatory basis for the ANO-1 Flow Accelerated Corrosion Prevention Program include:

- NRC Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants*
- NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*

Operating Experience and Demonstration: From the start of the eighth refueling outage to the end of the fifteenth refueling outage, approximately nine hundred inspections have been accomplished. Resulting from these inspections, approximately one hundred twenty-five components were replaced. When replacements are required, the materials used are resistant to flow accelerated corrosion damage. This program has proven effective in managing the loss of material caused by flow accelerated corrosion. Based on operating experience, the continued implementation of the Flow Accelerated Corrosion Program provides reasonable assurance that the effects of aging will be adequately managed so that the main steam and main feedwater systems will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.10 Inspection and Preventive Maintenance of the ANO-1 Polar Crane

Purpose: This program provides for the inspection and preventive maintenance of the ANO-1 polar crane.

Scope: Structural steel associated with the ANO-1 polar crane.

Aging effects: The aging effect managed by the Inspection and Preventive Maintenance of the ANO-1 Polar Crane is a loss of material.

Method: The polar crane steel components are visually inspected in accordance with the governing procedure. In addition to a visual inspection, the cranes bridge system bolting tightness is tested by hand.

Industry Codes of Standards: The polar crane is inspected, tested, and maintained in compliance with ANSI B30.2.

Frequency: The polar crane steel components are inspected annually, in conjunction with other periodic crane inspection activities.

Acceptance Criteria of Standard: The acceptance criteria for this inspection are no visual indications of deformation, cracking, loose or corroded (i.e., loss of material) members, and no loose or missing bolts.

Regulatory Basis: ANO commitment to NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants.*

Operating Experience and Demonstration: Inspection findings related to the polar crane structural steel components have not identified indications of a loss of material (i.e., corrosion). However, visual inspections have proven effective in identifying indications of the applicable aging effects for the polar crane structures and components. The continued implementation of the Inspection and Preventive Maintenance of the ANO-1 Polar Crane provides reasonable assurance that the aging effect are managed such that the polar crane will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

4.11 INSTRUMENT AIR QUALITY

Purpose: The purpose of the Instrument Air Quality Program, with respect to license renewal, is to ensure that the instrument air supplied to components is maintained free of water and significant contaminants.

Scope: The Instrument Air Quality Program applies to those components within the scope of license renewal, supplied with instrument air where pressure boundary integrity is required for the component to perform its intended function.

Aging Effects: The aging effects addressed by the Instrument Air Quality Program are loss of material and cracking.

Method: Sampling is performed to verify the instrument air is dry. Testing also checks for contaminants or foreign material in the air supply.

Industry Code or Standards: ISA Quality Standard for Instrument Air, S7.3-1975 [Reference B-20] is an applicable industry standard used to develop the Instrument Air Quality Program.

Frequency: The frequency is in accordance with site procedures.

Acceptance Criteria or Standard: Acceptance criteria are based on guidance provided in ISA Quality Standard for Instrument Air, S7.3-1975.

Regulatory Basis: ANO commitment to NRC Generic Letter 88-14, *Instrument Air Supply System Problems Affecting Safety-Related Equipment*.

Operating Experience and Demonstration: The results of the periodic testing have verified the instrument air quality is being maintained. Based on this information, the continued implementation of the Instrument Air Quality Program provides reasonable assurance that the aging effects will be managed such that components supplied with instrument air will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.12 LEAKAGE DETECTION IN REACTOR BUILDING

Purpose: The purpose of leakage detection in the reactor building, with respect to license renewal, is to monitor for leakage to manage the consequences of cracking, loss of material, and loss of mechanical closure integrity.

Scope: Leakage detection in the reactor building is focused on RCS leakage, but also includes other systems that have the potential to leak in the reactor building.

Aging Effects: Monitoring for leakage in the reactor building is credited as one of the methods of managing the aging effects of cracking, loss of material, and loss of mechanical closure integrity.

Method: Leakage detection in the reactor building is accomplished by three different means. These are the inventory balance, the reactor building sump monitoring, and the reactor building atmosphere radioactivity monitoring.

Reactor Coolant Inventory Balance

ANO-1 Technical Specification Table 4.1-2 requires the RCS leak rate to be determined periodically. RCS allowable leakage is limited, during power operation, as specified in ANO-1 Technical Specification 3.1.6. The envelope for leakage monitoring is the RCS and makeup system with all leakage assumed to be from the RCS unless proven otherwise.

Reactor Building Sump Monitoring

The reactor building sump fill rate is trended, and in conjunction with the RCS leak rate, is used for an indication of the source of leakage into the sump (i.e. leakage inside/outside the reactor building, RCS leakage or non-RCS leakage such as from main feedwater or main steam systems, etc.).

Reactor Building Radioactivity Monitoring

The reactor building leak detector consists of the reactor building atmosphere particulate detector and the reactor building atmosphere gaseous detector. These monitor readings are recorded on operator logs.

Industry Code or Standards: Not applicable.

Frequency: Potential indicators of RCS leakage are monitored continuously throughout each shift. The RCS leak rate determination is performed as required by ANO-1 Technical Specification 3.1.6 and Table 4.1-2 and ANO-1 site procedures.

Acceptance Criteria or Standard: The RCS allowable leakage is limited as specified in ANO-1 Technical Specification 3.1.6. Identified non-RCS leakage is evaluated on a case-by-case basis.

Regulatory Basis: ANO-1 Technical Specification 3.1.6 and Table 4.1-2 provide the regulatory basis for this program.

Operating Experience and Demonstration: A review of ANO-1 operating experience (i.e. ANO-1 specific licensee event reports dating back to 1984) confirms that these activities are effective in detecting leakage in the reactor building. In 1989, a non-isolable leak on a reactor coolant system drain line was detected when RCS leakage increased from the previous day's leak rate by approximately 0.2 gpm (to a total of 0.74 gpm). Although the cause of this leak was attributed to a weld defect and not an aging effect, this example demonstrates the program is effective in detecting small amounts of RCS leakage. Leaks caused by cracking, loss of material, or loss of mechanical closure integrity would be detected by this program. Based on operating experience, the continued implementation of Leakage Detection in the Reactor Building provides reasonable assurance that the effects of aging will be adequately detected and managed so that the systems within scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.13 MAINTENANCE RULE

Purpose: Maintenance Rule system and structural walkdowns are conducted to detect and manage aging effects of structures and components within the scope of the license renewal.

Scope: Structural components and commodities within the scope of license renewal and managed under the Maintenance Rule are listed in Tables 3.6-1 through 3.6-8. Coatings inspections apply to coated surfaces of ANO-1 structures and components within the scope of license renewal.

Aging Effects: The Maintenance Rule is utilized to manage cracking, loss of material, and change in material properties of structures and components within the scope of license renewal.

Method: Visual inspections of structures and components are performed.

Industry Codes or Standards: Not applicable.

Frequency: Structural and component walkdowns are performed periodically, and the frequency varies depending on the structure or component being inspected.

Acceptance Criteria or Standards: No unacceptable visual indications of cracking, loss of material, or change of material properties of structures or components.

Timing of New Program or Activity: Incorporate additional guidance for coatings inspections as part of existing system and structural walkdowns during next revision of System Engineering Desk Guide, but no later than the end of the initial 40-year license term for ANO-1.

Regulatory Basis: The Maintenance Rule is consistent with the requirements of 10CFR50.65.

Operating Experience and Demonstration: The ANO-1 history of successful operation demonstrates that visual inspections have been effective in managing the effects of aging on structures and components. This is indicative that the Maintenance Rule will be effective in the future for managing aging effects, since it incorporates proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls from existing programs and procedures. Based on this experience, the continued implementation of the Maintenance Rule provides reasonable assurance that the effects of aging will be adequately managed so that the systems within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.14 OIL ANALYSIS

Purpose: The purpose of the Oil Analysis Program is to ensure the oil environment in the mechanical systems is maintained to the quality required. Oil analysis program controls are credited as a program for maintaining oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to corrosion.

Scope: The scope of the Oil Analysis Program, with respect to license renewal, is limited to sampling and analysis of lubricants in the following components.

- Auxiliary building electrical room chillers
- Emergency diesel generators
- Decay heat pumps
- Reactor building spray pumps
- Primary makeup pumps
- Diesel driven fire pump and engine
- EFW pumps and EFW turbine
- Alternate AC diesel generator
- Control room ventilation compressors

Aging Effects: The Oil Analysis Program has been credited for ensuring the oil is free of water or contaminants. This manages the aging effects of cracking and loss of material.

Method: For components that have oil changes at intervals that satisfy the recommendations of the equipment manufacturer, a particle count and check for water are performed to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. For components that do not have regular oil changes, viscosity and neutralization number are determined to verify the oil is suitable for continued use. Specialized sampling and testing is performed for some components based on their specific use and vendor recommendations.

Industry Code or Standards: References used to develop this program include:

- ASTM D95, *Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation* [Reference B-21]
- ASTM D664, *Standard Test Method for Neutralization Number by Potentiometric Titration* [Reference B-22]

Frequency: The frequency of sampling is based upon equipment manufacturer recommendations and standard industry practices for each component.

Acceptance Criteria or Standard: The acceptance criteria for the Oil Analysis Program are contained in site procedures.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: Review of historical oil sampling plots for components in the scope of license renewal verifies that the lubricating oil is maintained free of excess water. For all non-engine oils, the total acid number is measured to verify contamination is not occurring that has impacted oil acidity. For engine oils, the total base number is measured and trended to verify that the oil is being maintained with enough additives to neutralize any acid that forms due to engine operation. Based on this information, the continued implementation of the Oil Analysis Program provides reasonable assurance that the aging effects will be managed such that the applicable components will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

4.15 Preventive Maintenance

Purpose: The purpose of the Preventive Maintenance Program is to perform preplanned, repetitive maintenance tasks on plant components and systems with the intent to extend equipment operating life and to minimize the possibility of in-service component failures.

Scope: The scope of the Preventive Maintenance Program, with regard to license renewal, is those preventive maintenance tasks credited with managing the aging effects identified in Section 3.0 of the LRA. Below is a list of preventive maintenance activities and the aging effects that they address.

Preventive Maintenance Activity	Aging Effect
Borated water storage tank internal inspection	Loss of material
Borated water storage tank external inspection	Loss of material and loss of mechanical closure integrity
Reactor building ventilation cooling coil cleaning and inspection	Fouling and loss of material
Hydrogen sampling system cabinet / heat exchanger cleaning, inspection, and lubrication	Fouling
Emergency fire diesel cooling water quarterly sampling for corrosion inhibitor	Loss of material
Penetration room floor drain check valves inspection	Loss of material and cracking
Decay heat room drain valves inspection	Loss of material, cracking, and loss of mechanical closure integrity
Emergency diesel fuel oil tank inspection	Loss of material
Emergency diesel generator HVAC components inspection	Loss of material and loss of mechanical closure integrity
Control room ventilation inspections	Fouling and loss of material
Battery Charger and Penetration Room Cooler Cleaning & Inspection	Loss of material and loss of mechanical closure integrity

Preventive Maintenance Activity	Aging Effect
Auxiliary Building Switchgear Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling
Auxiliary Building Decay and Heat Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling
HPI Room Coolers Cleaning and Inspection	Loss of material, loss of mechanical closure integrity, and fouling

Aging Effects: The aging effects addressed by the Preventive Maintenance Program are identified in the above table.

Method: The Preventive Maintenance Program consists of preplanned repetitive tasks for maintenance activities on plant components. These activities include periodic inspections, tests, calibrations, measurements and adjustments, cleaning, sampling or analysis, lubrication, and the replacement of limited life parts or components. The required maintenance activities are defined by preventive maintenance engineering evaluations. Vendor recommendations, ANO commitments, equipment history, industry experience and owners group recommendations are considered in these evaluations.

Industry Code or Standards: Not applicable.

Frequency: The frequency of the performance of preventive maintenance tasks is based on recommendations in the preventive maintenance engineering evaluations. The scheduling of preventive maintenance task is established to coincide with any previously schedule-related tasks, system outages, or component outages as applicable.

Acceptance Criteria or Standard: Applicable acceptance criteria are provided for each repetitive maintenance task based on the preventive maintenance engineering evaluations. Existing preventive maintenance procedures that do not adequately address inspection criteria for aging effects will be updated to provide appropriate inspection criteria.

Timing of New Program or Activity: New preventive maintenance activities that address inspection criteria for aging effects will be incorporated into existing preventive maintenance procedures prior to the end of the initial 40-year license term for ANO-1.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: The ANO-1 history of successful operation demonstrates that typical preventive maintenance activities, such as visual inspections, cleaning, and sampling, have been effective in managing the effects of aging on components. This is indicative that the Preventive Maintenance activity will be effective in the future for managing aging effects since it consists of proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls in existing programs and procedures. Based on this experience, the continuation of the Preventive

Maintenance activity provides reasonable assurance that the effects of aging will be adequately managed so that the components within the scope of this program will perform their intended functions consistent with the current licensing basis for the period of extended operation

4.16 REACTOR BUILDING LEAK RATE TESTING

The Reactor Building Leak Rate Testing Program provides assurance that leakage from the reactor building will not exceed required maximum values for reactor building leakage. The Reactor Building Leak Rate Testing Program consists of Type A, Type B, and Type C testing.

Type A testing measures the primary reactor building overall integrated leakage rate. This is also known as Integrated Leak Rate Testing.

Type B testing measures the leakage across air locks, door seals, equalizing valves, and test ports whose designs incorporate resilient seals, gaskets, and flexible metal seals.

Type C testing measures primary reactor building isolation valve leakage rates, whether the valves are manual or automatic. Generically, Type B and Type C tests are also known as local leak rate testing.

For the purposes of aging management programs for license renewal, only Type A and Type C tests are considered.

4.16.1 Integrated Leak Rate Testing

Purpose: The purpose of the integrated leak rate test is to measure the primary reactor building overall integrated leakage rate.

Scope: The scope of the integrated leak rate test is the reactor building.

Aging Effects: Type A integrated leak rate testing identifies loss of material or cracking.

Method: The integrated leak rate test pressurizes the reactor building to the peak calculated reactor building internal pressure, for the design basis loss of coolant accident, and monitors the rate of pressure drop. A leak rate is calculated based on the rate of the pressure drop observed.

Industry Code or Standards: Guidelines for the testing is provided by:

- ANSI/ANS 56.8, 1994, *Containment System Leakage Testing Requirements* [Reference B-14]
- ANSI N45.4, 1972, *Leakage Rate Testing of Containment Structures for Nuclear Reactors* [Reference B-15]

Frequency: Integrated leak rate tests are required once per ten years as long as calculated leakage remains less than the maximum allowable leakage rate.

Acceptance Criteria or Standard: The maximum allowable reactor building leakage rate is defined in the technical specifications.

Regulatory Basis: The regulatory basis for this program includes 10CFR50.54; 10CFR50 Appendix J option B; Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program* and ANO-1 Technical Specification 6.8.4.

Operating Experience and Demonstration: Historically, integrated leakage rates have been well within the maximum allowable leakage rates specified in the technical specifications. The continued implementation of the integrated leak rate testing provides reasonable assurance that the aging effects will be managed such the reactor building will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.16.2 Local Leak Rate Testing

Purpose: The purpose of the local leak rate test is to measure the leakage across individual penetration components and determine the leakage of each penetration.

Scope: Local Leak Rate Testing addresses leakage across reactor building penetrations.

Aging Effects: Local leak rate testing identifies changes in material properties, loss of material, and cracking.

Method: The local leak rate testing measures leakage on individual components by pressurizing the penetration to the specified test pressure.

Industry Code or Standards: Guidance for the local leak rate testing is provided by:

- ANSI/ANS 56.8, 1994, *Containment System Leakage Testing Requirements [Reference B-14]*
- ANSI N45.4, 1972, *Leakage Rate Testing of Containment Structures for Nuclear Reactors [Reference B-15]*

Frequency: Local leak rate tests are based on past local leak rate test results, service conditions, design, safety impact, previous failure causes, and common mode failure detection. Local leak rate tests are required when any adjustment or maintenance on an isolation barrier is performed that can affect sealing characteristics. Examples are replacement of packing, adjustments to valve stroke or closure switch settings, or lapping of valve seats.

Acceptance Criteria or Standard: The maximum allowable reactor building leakage rate is defined in ANO-1 Technical Specification 6.8.4.

Regulatory Basis: The regulatory basis for this program includes 10CFR50.54; 10CFR50 Appendix J; Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program* and ANO-1 Technical Specification 6.8.4.

Operating Experience and Demonstration: The sum of the leakage rates, at accident pressure, of Type B tests and pathway leakage rates from Type C tests, have been maintained less than the maximum allowable leakage rate, with margin, as specified in the technical specifications. The continued implementation of the local leak rate testing provides reasonable assurance that the aging effects will be managed such the reactor building will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.17 Reactor Building Sump Closeout Inspection

Purpose: The purpose of the Reactor Building Sump Closeout Inspection is to detect significant degradation of the sump components and remove any foreign objects that could impede suction from the sump.

Scope: The Reactor Building Sump Closeout Inspection applies to ANO-1 reactor building sump, the area immediately surrounding the sump, the screening materials, and the equipment and structural components inside the sump.

Aging Effects: The aging effects addressed by the Reactor Building Sump Closeout Inspection are loss of material for the carbon steel components and cracking for stainless steel components due to the presence of borated water.

Method: The Reactor Building Sump Closeout Inspection is a visual inspection of the exterior and interior surfaces of the sump. If the inspection is associated with a limited scope outage and the screens are not unbolted, or controls for a foreign material exclusion area are in place, then only exterior surfaces of the sump are inspected.

Industry Code or Standards: Not applicable.

Frequency: As a minimum, this inspection is performed at the end of each refueling outage.

Acceptance Criteria or Standard: Acceptance criteria are based on guidance provided in the closeout inspection procedure. Surfaces are inspected for evidence of the following: significant structural distress, corrosion, excessive rust, significant physical degradation, obvious loose or missing bolts, excessive hatch gap, or tears in sump screens. The reactor building sump screen is inspected for excessive openings or gaps in the screen. The sump internal inspection also verifies that there is no obvious loose bolting in the internal area of the sump and that no excessive corrosion or loss of material exists on the bolting and yokes of valves or on the divider plate. The inspection verifies that there is no excessive pitting or corrosion on piping external surfaces or flued heads.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: As detailed during the 1998 inspection, wetted portions of the sump were inspected for indications of aging effects. Structural members showed very little evidence of corrosion. Some light boron was removed which had formed due to a leaking valve above the sump. No service induced, or environmentally induced deficiencies were found with respect to carbon or stainless steel valve parts. The carbon steel portions of the divider plate were beginning to show light corrosion and rust along the bottom edge and up both sides. Flued heads showed no signs of service induced or environmentally induced pitting, cracking, or corrosion.

This experience demonstrates that continuation of the Reactor Building Sump Closeout Inspection provides reasonable assurance that aging affects will be managed such that the reactor building sump will continue to perform its intended functions consistent with the current licensing basis during the period of extended operation.

4.18 REACTOR VESSEL INTEGRITY

Section 2.3.1 of the ANO-1 LRA identifies the reactor vessel as a component that is subject to aging management review for license renewal. For the reactor vessel, Section 3.2.5 and Table 3.2-1 identify reduction in fracture toughness as the aging effect requiring management for the period of extended operation. The ANO-1 Reactor Vessel Integrity Program will manage the aging effect of reduction in fracture toughness of the reactor vessel. The ANO-1 Reactor Vessel Integrity Program consists of the following five interrelated subprograms.

- Master Integrated Reactor Vessel Surveillance Program
- Cavity Dosimetry Program
- Fluence and Uncertainty Calculations
- Pressure/Temperature Limits
- Monitoring Effective Full Power Years

Entergy Operations complies with the requirements of 10CFR50.60, Appendices G and H, and 10CFR50.61, through the ANO-1 Reactor Vessel Integrity Program. In accordance with 10CFR50.60 and 10CFR50.61, periodic updates for the five subprograms are provided to the NRC for review.

Continuation of the Reactor Vessel Integrity Program provides reasonable assurance that applicable aging effects will be managed such that the reactor vessel will continue to perform its intended functions consistent with the current licensing basis during the period of extended operation.

4.18.1 Master Integrated Reactor Vessel Surveillance

Entergy is a participant in the BWOG Master Integrated Reactor Vessel Surveillance Program. The Master Integrated Reactor Vessel Program meets the requirements of Appendix H of 10CFR Part 50, with regard to integrated surveillance programs (paragraph III.C). In addition, the Master Integrated Reactor Vessel Program addresses reference temperature shift concerns and pressurized thermal shock in accordance with 10CFR50.61. A description of the Master Integrated Reactor Vessel Program is provided in BAW-1543A, Revision 2 [Reference B-23] and in BAW-2251A [Reference B-24].

Purpose: The purpose of the Master Integrated Reactor Vessel Program is to provide a method to monitor reactor pressure vessel materials containing Linde 80 high copper beltline welds for determining the reduction of material toughness by neutron irradiation embrittlement.

Scope: The scope of the Master Integrated Reactor Vessel Program includes beltline plate and weld material for the beltline region of the ANO-1 reactor vessel.

Aging Effects: The aging effect requiring management is the reduction of material toughness by neutron irradiation embrittlement.

Method: Fracture toughness specimens are irradiated within two operating B&W reactor vessels (i.e., Davis-Besse and Crystal River–3) and the participating Westinghouse reactor vessels. The specimens are irradiated in capsules located near the reactor vessel inside wall, thus enabling reactor vessel materials to become irradiated to beyond anticipated license renewal fluence levels. The fracture toughness specimens are tested in accordance with the applicable ASTM standards identified in Section 5.0 of BAW-1543A, Revision 2.

Industry Code or Standard: ASTM E185 [Reference B-25]; ASTM E900 [Reference B-30]; ASTM standards as identified in Section 5.0 of BAW-1543.

Frequency: The capsule withdrawal schedules are presented in BAW-1543, Revision 4, Supplement 3. The Master Integrated Reactor Vessel Program schedule may be altered due to unscheduled downtimes or extended outages at the host plants. In addition, certain surveillance capsules may receive additional irradiation to fully satisfy license renewal fluence requirements.

Acceptance Criteria or Standard: Fracture toughness specimens removed from the surveillance capsules will be laboratory tested to ensure reactor vessel fracture toughness properties exhibit upper shelf energy greater than 50 ft-lbs. If the Charpy upper shelf energy drops below 50 ft-lbs, then it must be demonstrated that margins of safety against fracture are equivalent to those of Appendix G of ASME Section XI. In addition, calculations of reference temperature for pressurized thermal shock (RT_{PTS}) must be below the screening criteria of 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds. If the projected reference temperature exceeds the screening criteria, licensees are required to submit an analysis and schedule for such flux reduction programs as are reasonably practicable, to avoid exceeding the screening criteria. If no reasonably practicable flux reduction program will avoid exceeding the screening criteria, licensees shall submit a safety analysis to determine what actions are necessary to prevent potential failure of the reactor vessel if continued operation beyond the screening criteria is allowed.

Regulatory Basis: 10CFR50.60, *Acceptance Criteria for Fracture Prevention Measures for Light Water Nuclear Power Reactors for Normal Operation*; 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock*; Appendix G to Part 50, *Fracture Toughness Requirements*; Appendix H to Part 50, *Reactor Vessel Material Surveillance Program Requirements*; and ANO-1 Technical Specification 3.1.2, *Pressurization, Heatup, and Cooldown Limitations.*

4.18.2 Cavity Dosimetry

Purpose: The purpose of the Cavity Dosimetry Program is to verify the accuracy of fluence calculations and to determine fluence uncertainty values.

Scope: The ANO-1 reactor vessel has installed cavity dosimetry.

Aging Effects: The reduction of material toughness by irradiation embrittlement.

Method: Dosimeters (i.e., U_{238}, Np_{237}, Ni, Cu, etc.) are irradiated in the cavity region outside of the ANO-1 reactor vessel. Cavity dosimetry was irradiated at ANO-1 for Cycles 10, 11, and 12, and combined Cycles 13 and 14. At present, cavity dosimetry is being irradiated at ANO-1 for combined cycles 15 and 16.

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.

Industry Code or Standard: ASTM E185 [Reference B-25] and ASTM E900 [Reference B-30].

Frequency: At present, cavity dosimetry is changed out on an every-other-cycle basis. Projections indicate extending the frequency to an every-third-cycle exchange period or longer may be acceptable. The cavity dosimetry exchange schedule may be altered due to changes in fuel type, fuel loading pattern, or power rating of ANO-1.

Acceptance Criteria or Standard: Not applicable. This information is used in conjunction with the fluence and uncertainty calculations.

Regulatory Basis: 10CFR50.60, *Acceptance Criteria for Fracture Prevention Measures for Light Water Nuclear Power Reactors for Normal Operation*; Appendix H to Part 50, *Reactor Vessel Material Surveillance Program Requirements*; BAW-2241A-P, and 10CFR50.61.

4.18.3 Fluence and Uncertainty Calculations

Purpose: The purpose of the reactor vessel fluence and uncertainty calculations is to provide an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value for use in development of the pressure/temperature limit curves and pressurized thermal shock calculations.

Scope: The fluence and uncertainty calculations apply to the ANO-1 reactor vessel.

Aging Effect: The reduction of material toughness by neutron irradiation embrittlement.

Method: The cavity dosimetry program yields irradiated dosimeters that are analyzed based on ANO-1 specific geometry models (i.e., fuel, reactor vessel, capsule holders, concrete structures), macroscopic cross sections, cycle-specific sources using the DORT and GIP computer codes, and reference microscopic cross section (BUGLE 93). Specific attention is given to target fluence values for limiting reactor vessel beltline weld locations. Recently updated fluence and uncertainty calculations were based on cavity dosimetry irradiated at ANO-1 for cycles 10 through 14. Future calculation revisions will be based on cavity dosimetry being irradiated at ANO-1 for combined cycles 15 and 16.

Industry Code or Standard: ASTM E900 [Reference B-30] and ASTM E185 [Reference B-25].

Frequency: Fluence and uncertainty calculations are expected to follow each cavity dosimetry analysis for the next few years. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. Future decisions concerning the frequency of withdrawal of dosimetry will be based on changes in fuel type or fuel loading pattern.

Acceptance Criteria or Standard: The fluence uncertainty values are to be within the NRC-suggested limit of ±20%. Calculated fluence values for fluence levels above 1.0 MeV are compared with the measurement values to determine if calculations contain any errors. The method represents a continuous validation process to ensure that no biases have been introduced and that the uncertainties remain comparable to the reference benchmarks.

Regulatory Basis: Appendix H of 10CFR Part 50, *Reactor Vessel Material Surveillance Program Requirements*; BAW-2241A-P; and BAW-2251A.

4.18.4 Pressure/Temperature Limit Curves

Purpose: The purpose of the pressure/temperature limit curves is to establish the normal operating, inservice leak test, and hydrostatic test transient limits for the RCS.

Scope: The pressure/temperature limit curves apply to the ANO-1 reactor vessel.

Aging Effects: The change of material properties by neutron irradiation embrittlement.

Method: Pressure/temperature curves are generated assuming a postulated 1/4T surface flaw in accordance with ASME Section XI, Appendix G. Bounding input heatup and cooldown transients are used to develop the pressure/temperature curves.

Industry Code or Standard: ASME Section XI, Appendix G, 1989 Edition; ASME Code Case N-514; ASTM E900 [Reference B-30].

Frequency: Pressure/temperature limit curves are valid for a period expressed in effective full power years. The curves are required to be updated prior to exceeding this time period.

Acceptance Criteria or Standard: Pressure/temperature limit curves must be in place for continued plant operation.

Regulatory Basis: ANO-1 Technical Specification 3.1.2 and BAW-10046 [Reference B-27]

4.18.5 Effective Full Power Years

Purpose: The purpose of determining the EFPY is to accurately monitor and tabulate the accumulated operating time experienced by the reactor vessel.

Scope: The EFPY activity applies to the ANO-1 reactor vessel.

Aging Effect: The reduction of material toughness by neutron irradiation embrittlement.

Method: The effective full power days of plant operation are based on reactor incore power readings. The Nuclear Applications Software, which runs on the plant computer, collects incore instrument data. Site reactor engineers determine effective full power days values by comparing the burnup to the thermal power calculated burnup. The data is collected continuously.

Industry Code or Standard: Not applicable.

Frequency: ANO-1 is continuously computer monitored and updated weekly by site reactor engineers to determine the effective full power days of reactor coolant system operation during the previous seven day period.

Acceptance Criteria or Standard: For a given fuel cycle, the updated effective full power days calculation based on the power history must be within ±0.3 EFPD of the plant computer generated value.

Regulatory Basis: ANO-1 Technical Specification 3.1.2.

4.19 SERVICE WATER INTEGRITY

Purpose: The purpose of the Service Water Integrity Program is to ensure the ANO service water system components continue to operate and perform their safety-related functions for the remaining life of ANO-1. The Service Water Integrity Program activities are integrated into the normal system engineering responsibilities that include such duties as performance monitoring, Maintenance Rule administration, and Generic Letter 89-13 compliance.

Scope: The scope of the Service Water Integrity Program, with respect to license renewal is limited to activities on ANO-1 service water system components and structures, including the emergency cooling pond.

Aging Effects: The Service Water Integrity Program is credited with managing the following aging effects.

- The flow rate testing ensures the effects of fouling do not reduce flow rates below required values. System cleaning is performed when necessary to maintain cleanliness in accordance with GL 89-13 commitments.
- The heat exchanger testing manages the aging effect of fouling by ensuring the heat exchangers can remove the necessary heat load.
- The thickness mapping and visual inspections manage the effects of loss of material from the service water components.
- Visual inspections of a sample of safety-related valves and heat exchangers manage the effect of cracking of the components.
- The service water bay inspection manages loss of material for the mechanical components in the service water bay.

Method: The ANO-1 Service Water Integrity Program consists of the following testing activities to achieve the program objectives committed to in the Generic Letter 89-13 responses.

- Flow testing of safety related heat exchangers every refueling outage
- Heat transfer testing or inspections of heat exchangers
- Pump performance testing in accordance with ASME Section XI
- Flushing and minimum flow testing of the reactor building coolers in accordance with the technical specifications
- Testing of the sluice gates and system boundary valves for leakage

Non-destructive examinations commitments in Generic Letter 89-13 responses include the following.

- Cleaning and inspecting the intake structure service water bay and sluice gates on a periodic basis
- Mapping pipe thickness at selected locations
- Visual inspections of a sample of the safety related heat exchangers and valves
- Inspections of the epoxy coating internal to the ECP return line

Chemical controls commitments in Generic Letter 89-13 responses include the following.

- Treatment with biocides to minimize macrobiological fouling and MIC
- A side stream corrosion rack or other acceptable methods for detailed monitoring of the corrosion and chemical effects
- Addition of a corrosion inhibitor, to the extent practical to reduce the corrosion rate of the system carbon steel piping

Other activities also include:

- The periodic flushing of pump bearing coolers and stagnant portions of the service water piping
- Mechanical or chemical cleaning, when necessary, to remove fouling

Industry Code or Standards: Not applicable.

Frequency: The frequency of activities is specified in site procedures. The frequency may be adjusted based on the results of testing and inspection.

Acceptance Criteria or Standard: The acceptance criteria for the Service Water Integrity Program are located in site procedures.

Regulatory Basis: The regulatory basis for the Service Water Integrity Program is the ANO commitment to Generic Letter 89-13 [Reference B-31, B-32, B-33, B-34, and B-35].

Operating Experience and Demonstration: The Service Water Integrity Program, initially established for ANO-1 in 1980, is a comprehensive program to ensure operability of the service water system. The program involves chemistry controls, system and component testing, non-destructive examinations, and miscellaneous preventive maintenance activities that have proven effective in managing the effects of aging on plant components. These program activities consist of proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls in existing site procedures. The continuation of the Service Water Integrity Program provides reasonable assurance that the aging effects will be managed such that the components of the service water system will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.20 STEAM GENERATOR INTEGRITY

Purpose: The purpose of the Steam Generator Integrity Program is to ensure the steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The Steam Generator Integrity Program is structured to meet the Nuclear Energy Institute *Steam Generator Program Guidelines* (NEI 97-06) [Reference B-28], which includes the following essential elements.

- Assessment of potential degradation mechanisms
- Tube inspection
- Tube structural and leakage assessment
- Maintenance and repairs
- Primary-to-secondary leakage monitoring
- Secondary side water chemistry
- Primary side water chemistry
- Foreign material exclusion
- Secondary side integrity
- Self-assessments
- NRC reporting

Scope: The scope of the Steam Generator Integrity Program applies to the ANO-1 steam generator internals, tubing, and associated repair techniques and components, such as plugs and sleeves.

Aging Effects: The aging effects addressed by the Steam Generator Integrity Program are loss of material, cracking, and fouling.

Method: Eddy current inspections are completed as required by technical specifications and the Steam Generator Integrity Program. The technical specifications require eddy-current testing, or other equivalent technique, that is capable of detecting defects with a penetration of 20% or more of the minimum allowable, as-manufactured tube wall thickness. To ensure adequate detection sensitivity, the techniques used during the eddy current inspections are qualified or demonstrated equivalent to the EPRI PWR Steam Generator Examination Guidelines. In many cases, this requires testing of the steam generator tubes with multiple techniques.

The secondary side internals of the steam generators are assessed each outage and inspections are periodically performed in accordance with procedural requirements. Leak testing may be performed to locate a primary to secondary leak, and tube pulls can be performed, when necessary, to further evaluate flaw morphology and assess structural and leakage integrity.

Industry Code or Standards: Industry codes and standards utilized for this program include the ASME Boiler and Pressure Vessel Code, Section XI.

Frequency: The frequency of inspections is based on the technical specifications. Additionally, the post outage tube integrity evaluation is performed to ensure the operating interval is justified.

Acceptance Criteria or Standard: Site procedures, technical specifications, and engineering evaluations provide the acceptance criteria. The detailed tube repair criterion is documented in an engineering evaluation prior to each eddy current inspection.

Regulatory Basis: ANO-1 Technical Specification 4.18.

Operating Experience and Demonstration: Detailed OTSG operating experience is routinely compiled by the BWOG and included in the plant-to-plant trending report. Additionally, the evaluations performed for the tube integrity include ANO-1 specific operating experience. Steam generator inspection and testing activities have proven effective in identifying indications of aging effects such as cracking and loss of material. Corrective actions within this program have been successful in correcting the identified deficiencies. Based on this information, the Steam Generator Integrity Program provides reasonable assurance that the aging effects will be managed such that the steam generators will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.21 System and Component Monitoring, Inspections, and Testing

A number of miscellaneous system and component monitoring, inspection, and testing activities are credited for managing the effects of aging. These existing activities are typically surveillance activities required by the technical specifications that are not considered part of a larger program or activity. In general, these activities are conducted on a periodic basis to verify the continuing capability of safety-related structures, systems, and components to meet established performance requirements. These credited activities are described in the following sections.

4.21.1 Annual Emergency Cooling Pond Sounding

Purpose: The annual emergency cooling pond sounding verifies the availability of a sufficient supply of cooling water to handle design basis accidents, with a concurrent loss of the Dardanelle Reservoir.

Scope: The emergency cooling pond and surrounding structural components.

Aging Effects: Loss of form of the emergency cooling pond due to sedimentation.

Method: Accessible and exposed surfaces are visually inspected along with sounding for pond level. Areas of the cooling pond are inspected for excessive erosion, degradation of rip rap, or silt build-up.

Industry Codes or Standards: Not applicable.

Frequency: The emergency cooling pond and its structural components are inspected annually.

Acceptance Criteria: Acceptance criteria established in applicable site procedures are based on technical specifications to ensure that sufficient inventory will be maintained in the emergency cooling pond.

Regulatory Basis: Emergency cooling pond inspections meet the surveillance requirements of ANO-1 Technical Specification 4.13.

Operating Experience and Demonstration: A review of in-house documentation showed that emergency cooling pond deficiencies have been identified during ECP inspections. The identified deficiencies include torn sandbags, out-of-place riprap, eroded banks and a broken drain. Applicable station procedures ensure that adequate corrective measures are taken when such deficiencies are identified during inspection.

Based on the above review, continued implementation of the Annual Emergency Cooling Pond Sounding provides reasonable assurance that the effects of aging will be managed such that the emergency cooling pond will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.21.2 Battery Quarterly Surveillance

Purpose: The purpose of the battery rack inspections is to ensure their structural integrity.

Scope: Seismically-qualified battery racks are within the scope.

Aging Effects: Battery racks and associated threaded fasteners are inspected for physical damage or abnormal deterioration, including a loss of material.

Method: The battery racks are visually inspected as part of the battery quarterly surveillance.

Industry Code or Standard: ANSI/IEEE Standard 450-1980: *IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations* [Reference B-29].

Frequency: In association with other battery maintenance activities, battery rack inspections are performed on a quarterly basis.

Acceptance Criteria: The battery racks are considered acceptable if there are no visual indications of degradation. Deficiencies, when noted, are evaluated to determine if the damage or deterioration affects the ability of the battery banks to perform their function.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: A review of ANO-1 condition report summaries did not identify indications of damage to, or deterioration of, the battery racks. While battery rack inspections have identified no evidence of loss of material, visual inspections in general have proven effective in identifying degradation that would be indicative of this aging effect. The continuation of this activity will provide reasonable assurance that the effects of aging will be adequately managed so that the battery racks will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

4.21.3 Control Room Ventilation Testing

Purpose: With respect to license renewal, Control Room Ventilation Testing is credited as one of the programs to manage aging effects.

Scope: The control room ventilation testing applies to the control room emergency cooling coils.

Aging Effects: Fouling on the external surfaces of the cooling coil tubes is the aging effect managed by this program.

Method: Per ANO-1 Technical Specification 4.10, each train of the control room emergency air conditioning system is demonstrated operable at least once per 31 days. This testing provides evidence that excessive fouling is not present.

Industry Standard or Codes: Not applicable.

Frequency: Each train is tested once per 31 days. At least once per 18 months, the system flow rate is verified.

Acceptance Criteria: The acceptance criteria for testing are provided in ANO-1 Technical Specification 4.10.

Regulatory Basis: ANO-1 Technical Specification 4.10

Operating Experience and Demonstration: A review of ANO-1 condition report summaries did not identify fouling of the cooling coils. In conjunction with control room ventilation system inspection under the PM Program and the Heat Exchanger Monitoring Program, the continued implementation of Control Room Ventilation Testing will provide reasonable assurance that fouling of the cooling coils will be adequately managed so that the control room ventilation system will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

4.21.4 Core Flood Tank Monitoring

Purpose: With respect to license renewal, the core flood tank monitoring provides a method to manage the aging effect of loss of material due to boric acid corrosion.

Scope: The core flood tank monitoring applies to both core flood tanks at ANO-1.

Aging Effects: The loss of material due to boric acid corrosion on parts wetted by leaks from the core flood tanks may be detected through core flood tank monitoring.

Method: Core flood tank level and pressure are monitored per ANO-1 operating procedures using installed control room instrumentation. Alarms activate if pressure or level moves outside the acceptable range.

Industry Standard or Codes: Not applicable.

Frequency: Core flood tank level and pressure are monitored once per shift during plant operation. Alarms activate if pressure or level moves outside the acceptable range.

Acceptance Criteria: The acceptance criteria for level and pressure are provided in site procedures.

Regulatory Basis: ANO-1 Technical Specification 4.1.a.

Operating Experience and Demonstration: Core flood tank level monitoring has proven effective in identifying level changes resulting from small amounts of leakage. This same monitoring activity is expected to identify aging effects resulting in similar small amounts of leakage. Based on the general effectiveness of core flood tank level monitoring in identifying leakage, the continuation of this activity will provide reasonable assurance that the effects of aging will be adequately managed so that the core flood system will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.21.5 Emergency Diesel Generator Testing and Inspections

Purpose: With respect to license renewal, Emergency Diesel Generator Testing and Inspections provide a means of detecting aging effects associated with the various emergency diesel generator subsystems.

Scope: The scope for testing and inspections includes the emergency diesel generator assembly and associated support components.

Aging Effects: Loss of material is an aging effect requiring management for the carbon steel components in the EDG starting air system. Loss of material is identified as an aging effect for the unpainted carbon steel internal surfaces and the outer portion of the intake that could be wetted by rain. Loss of material and fouling are considered aging effects for the EDG intake air aftercoolers. Loss of material from the piping and muffler internal surfaces and from external surfaces exposed to the weather is an aging effect for the EDG exhaust components. Loss of material and fouling are aging effects for the lube oil coolers. The cooling water carbon steel components are susceptible to a limited loss of material from corrosion and the stainless steel components have the aging effect of cracking. Loss of material and fouling are aging effects for the cooling water heat exchangers. Since the portions of the subsystems on the engine are exposed to high vibration, loss of bolted closure integrity was identified as an aging effect for the skid mounted and connected components.

Method: Per ANO-1 Technical Specification 4.6.1, each diesel generator is started each month and operated until the temperatures stabilize. Once every 18 months, the diesel generator is automatically started and operated for greater than one hour after the temperatures have stabilized. Also once every 18 months each diesel generator is given an inspection following the manufacturer's recommendations. The following are examples of the maintenance actions that support the management of aging effects.

- A pressure drop test is performed on the aftercoolers and the aftercoolers are cleaned if a high differential pressure is indicated. This would detect fouling of these heat exchangers.

- A check is made for exhaust leaks, cooling water leaks, or lube oil leaks while the engine is running. This would detect loss of bolted closure integrity, cracking or loss of material in these subsystems that had progressed to the point of allowing leakage.

- The air start components on the skid are disassembled and inspected. A leak check is performed on the tubing. This would detect significant loss of material or loss of integrity of the air start components.

- The exhaust manifold screen assembly is removed and inspected, which helps to detect loss of material at this location in the exhaust subsystem.

- The lube oil cooler is disassembled, inspected, and cleaned (interior and exterior of tubes) when necessary. This would detect loss of material or fouling.
- Throughout the inspection, the bolt torque is checked on a large number of components, thereby managing a loss of bolted closure integrity.

Industry Standard or Codes: Not applicable.

Frequency: Each emergency diesel generator is manually started monthly and automatically started every 18 months. Inspections are performed on an 18-month interval.

Acceptance Criteria: The acceptance criteria for testing and inspections are documented in emergency diesel generator operation and inspection procedures.

Regulatory Basis: ANO-1 Technical Specification 4.6.1 and NRC Regulatory Guide 1.108, *Periodic Testing of Emergency Diesel Generator Units Used As On-site Power Systems At Nuclear Power Plants.*

Operating Experience and Demonstration: Operational testing of the emergency diesel generators has proven effective in identifying loss of mechanical closure integrity of air, lube oil, and fuel oil systems components. Testing includes a 24-hour endurance run once per 18 months. Based on a review of industry experience and ANO condition reports regarding the emergency diesel generators, these tests and inspections provide reasonable assurance that the aging effects will be managed such that the emergency diesel generators will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.21.6 Emergency Feedwater Pump Testing

Purpose: With respect to license renewal, Emergency Feedwater Pump Testing is credited as one of the programs for managing the effects of aging.

Scope: The scope of Emergency Feedwater Pump Testing includes the turbine and electric motor driven emergency feedwater pumps and associated components.

Aging Effects: Fouling in the system heat exchangers is the primary aging effect that this testing will identify. This testing also is credited with identifying the aging effects of loss of material and loss of mechanical closure integrity for system components.

Method: Per ANO-1 Technical Specification 4.8, each train is demonstrated operable by verifying that each pump starts, and operates, through the test loop flow path.

Industry Standard or Codes: Not applicable.

Frequency: Each train is tested once per 31 days.

Acceptance Criteria: The acceptance criteria for testing are documented in ANO-1 Technical Specification 4.8.

Regulatory Basis: ANO-1 Technical Specification 4.8

Operating Experience and Demonstration: Emergency feedwater system testing challenges the pressure boundary and heat transfer functions for system components. A review of ANO-1 condition report summaries did not identify any occurrence of fouling of the system heat exchangers. The continued implementation of emergency feedwater pump testing provides reasonable assurance that fouling of the system heat exchangers will be detected and corrected so that the emergency feedwater system will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

4.21.7 NaOH Tank Level Monitoring

Purpose: The purpose of the NaOH tank level monitoring, with respect to license renewal, is to provide a method of detecting changes in the tank level that might indicate leakage from the NaOH tank or system.

Scope: The NaOH tank level monitoring applies to the NaOH system components.

Aging Effect: This inspection is credited with managing the aging effects of loss of material, loss of mechanical closure integrity, and cracking.

Method: The NaOH tank level is monitored through the use of a level alarm that actuates prior to exceeding the ANO-1 Technical Specification 3.3.4.B limits.

Industry Standard or Codes: Not applicable.

Frequency: The NaOH tank level is continuously monitored by the low level alarm feature.

Acceptance Criteria or Standards: Corrective action is initiated upon receipt of the NaOH tank low level alarm.

Regulatory Basis: ANO-1 Technical Specification 3.3.4.B

Operating Experience and Demonstration: A review of ANO-1 condition report summaries did not identify documentation of leakage from the chemical addition system boundary that could lead to the above identified aging effects. However, level monitoring in general has proven effective in leading to the identification and correction of small leaks. Continuation of NaOH tank level monitoring will provide reasonable assurance that the effects of aging will be adequately managed so that the chemical addition system will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.21.8 Spent Fuel Pool Level Monitoring

Purpose: The purpose of spent fuel pool level monitoring, with respect to license renewal, is to provide a method of detecting changes in the spent fuel pool level that might indicate cracks in the spent fuel pool liner.

Scope: The spent fuel pool level monitoring applies to the detection of leakage through the spent fuel pool liner.

Aging Effect: Cracking of the spent fuel pool liner is the aging effect addressed by spent fuel pool level monitoring.

Method: Operators record the spent fuel pool level during their rounds. Alarms are provided to indicate decreasing spent fuel pool level. If the spent fuel pool level dropped without explanation, operations will determine the cause and initiate corrective action. Leakage due to a through wall crack of the spent fuel liner would be identified by a decrease in spent fuel pool level.

Industry Standard or Codes: Not applicable.

Frequency: Operations records the spent fuel pool level once per shift. Spent fuel pool level is continuously monitored by the low level alarm feature.

Acceptance Criteria: The acceptance criterion for the spent fuel pool level is provided in site procedures.

Regulatory Basis: Not applicable.

Operating Experience and Demonstration: As documented in NRC Inspection Report 50-313/95-11; 50-368/95-11, 0CNA039524 [Reference B-8], the refueling cavity liner plate was found to have cracking during refueling outage 11. Welding of the new permanent seal plate is believed to have caused the previously existing cracks to propagate. Based on this condition, cracking is considered an applicable aging effect for the spent fuel pool liner. The cracking of the refueling canal liner plate occurred in the heat affected zone of the liner plate welds. Spent Fuel Pool Level Monitoring is one of the means of managing cracking of the spent fuel pool liner plate. In conjunction with the Spent Fuel Pool Monitoring Program described in Section 3.7 of this appendix, Spent Fuel Pool Level Monitoring will provide reasonable assurance that cracking of the liner plate will be managed such that the spent fuel pool will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.22 REFERENCES FOR APPENDIX B

B-1 Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule, NEI 95-10, Revision 0, Nuclear Energy Institute, March 1996.

B-2 Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants, Working Draft, NRC, September 1997.

B-3 BAW-2244A, *Demonstration of the Management of Aging Effects for the Pressurizer*, The B&W Owners Group Generic License Renewal Program, December 1997.

B-4 BAW-2248A, Demonstration of the Management of Aging Effects for the Reactor Vessel Internals, The B&W Owners Group Generic License Renewal Program, July 1997.

B-5 BAW-2243A, Demonstration of the Management of Aging Effects for the Reactor Coolant system Piping. The B&W Owners Group Generic License Renewal Program, June 1996.

B-6 1CAN059902, ANO letter dated May 6, 1999 to NRC, Annual Radiological Environmental Operating Report – 1998.

B-7 1CAN069804, ANO letter dated June 3, 1998 to NRC, Risk Informed Inservice Inspection Pilot Plant Submittal

B-8 0CNA039524, NRC letter dated March 31, 1995 to ANO, *NRC Inspection Report 50-313/95-11; 50-368/95-11*

B-9 BAW-2301, Degradation of Control Rod Drive Mechanism and Other Vessel Closure Head Penetrations, The B&W Owners Group Response to Generic Letter 97-01, July 1997.

B-10 1CAN048908, ANO letter dated April 13, 1989 to NRC, Information Submittal for Station Blackout Rule, 10CFR50.63

B-11 0CAN049107, ANO letter dated April 15, 1991 to NRC, Response to Station Blackout Safety Evaluation Report (TAC Nos.68508 and 68509).

B-12 0CAN088201, John R. Marshall (AP&L) letter dated August 2, 1982 to John T. Collins (NRC), Initial AP&L Response to IEB 82-02 – Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants.

B-13 0CAN058813, Dan R. Howard (AP&L) letter dated May 27, 1988 to Document Control Desk (NRC), Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants (Generic Letter 88-05).

B-14 ANS 56.8, Containment System Leakage Testing Requirements, ANS, 1994.

B-15 ANSI N45.4, Leakage Rate Testing of Containment Structures for Nuclear Reactors, ANSI, 1972.

B-16 BAW-2251A, Demonstration of the Management of Aging Effects for the Reactor Vessel, The B&W Owners Group Generic License Renewal Program, June 1996.

B-17 0CAN079703, ANO letter dated July 29, 1997 to NRC, *120 Day Response to Generic Letter 97-01*.

B-18 0CAN029908, ANO letter dated February 24, 1999 to NRC, Generic Letter 97-01 Request for Additional Information.

B-19 0CAN049705, ANO letter dated April 15, 1997 to NRC, *Monthly Operating Report*.

B-20 ISA S7.3, Quality Standard for Instrument Air, ISA, 1975.

B-21 ASTM D95, Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, ASTM, June 1999.

B-22 ASTM D664, Standard Test Method for Neutralization Number by Potentiometric Titration, ASTM, October 1995.

B-23 BAW-1543A, *Integrated Reactor Vessel Surveillance Program*, B&W Owners Group Materials Committee, May 1985.

B-24 BAW-2251A, *Demonstration of the Management of Aging Effects for the Reactor Vessel,* The B&W Owners Group Generic License Renewal Program, June 1996.

B-25 ASTM E185, Standard Practice for Conducting Surveillance Test for Light-Water Cooled Nuclear Power Reactor Vessels.

B-26 BAW-2241A-P, Fluence and Uncertainty Methodologies, April 1997.

B-27 BAW-10046, Revision 1, *Methods of Compliance with 10CFR50, Appendix G*, The B&W Owners Group.

B-28 NEI 97-06, Steam Generator Program Guidelines.

B-29 IEEE 450, IEEE Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Substations, IEEE, 1980.

B-30 ASTM E900, Standard Guide for Predicting Neutron Radiation Damage to Reactor Vessel Materials, ASTM, 1987.

B-31 0CAN019012, ANO letter dated January 26, 1990 to NRC, *Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment".*

B-32 0CAN119010, ANO letter dated November 30, 1990 to NRC, *Revision to Response to Generic Letter 89-13.*

B-33 0CAN099110, ANO letter dated October 3, 1991 to NRC, Implementation Status of Four Issues at ANO.

B-34 1CAN039209, ANO letter dated March 20, 1992 to NRC, *Modified Component Testing List for Generic Letter 89-13.*

B-35 0CAN109205, ANO letter dated October 30, 1992 to NRC, *Revised Approach for Compliance to NRC Generic Letter 89-13; Service Water.*

Appendix C

Process for Identifying Aging Effects Requiring Aging Management for Non-Class 1 Mechanical Components

1.0 INTRODUCTION

Entergy Operations utilized generic guidance developed as part of the BWOG Generic License Renewal Program as the primary basis for determining applicable aging effects for the ANO-1 non-Class 1 mechanical components. This appendix does not contain the detailed derivation of the aging effects that are applicable for the materials and environment combinations, but summarizes the process and the results to assist in the understanding of the aging effects identified in the LRA.

The potential aging effects for all mechanical components include the following.

- Loss of material
- Cracking
- Change in material properties
- Distortion
- Loss of mechanical closure integrity

An additional potential aging effect for heat exchangers and similar components, whose intended function is heat transfer, is fouling (loss of heat transfer capability).

Operating environments for mechanical systems within the scope of license renewal are discussed in the following sections of this appendix.

- Borated water (Section 2.0)
- Treated water (Section 3.0)
- Raw water (Section 4.0)
- Sodium hydroxide (Section 5.0)
- Oil and fuel oil (Section 6.0)
- Gas (Section 7.0)
- External environments (Section 8.0)

The following two special topics are also within the scope of license renewal.

- Bolted closures (Section 9.0)
- Heat exchangers (Section 10.0)

1.1 Mechanical Components Subject to Aging Management Review

In accordance with Appendix B of NEI 95-10 and the guidance provided in the 10CFR Part 54, only passive mechanical components are in the scope of review. Within the systems that are within the scope of license renewal, the following are typical components subject to aging management review.

- Heat exchangers
- Tanks/vessels
- Pump casings
- Valve bodies and bonnets
- Pipe, tubing, fittings, and branch connections
- Bolting
- Miscellaneous process components
- Filter housings
- Flex hose
- Expansion joints
- Traps
- Flow orifices
- In-line flowmeters
- Cyclone separators

Many of the mechanical components within the scope of license renewal contain gaskets, packing, and seals. However, these items are not subject to aging management review since they are not long lived and are defined as consumables. In addition, the NRC, in the SER on BAW-2244A [Reference 1-1], agreed that an aging management review was not required since a gasket, as a part of the bolted connection, exists to minimize leakage and is not solely responsible for providing the pressure boundary or supporting a structural load.

1.2 Materials Used in Non-Class 1 Components

The following materials are present in the non-Class 1 systems within the scope of license renewal.

- Stainless steels (wrought and cast)
- Nickel-base alloys (inconel)
- Carbon and low alloy (chrome-moly) steels
- Cast iron
- Copper alloys (bronze, brass, Admiralty, and copper-nickel)
- Aluminum
- Copper
- Glass
- Incoloy-800

1.3 Environments and Special Topics

1.3.1 Borated Water

Borated water is demineralized water containing boric acid. Aging effects for materials typically found in borated water environments are summarized in Section 2.0 of this appendix.

1.3.2 Treated Water

Treated water is demineralized water and is the base water for all clean systems. Depending on the system, treated water may require additional processing. Treated water could be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. Aging effects for materials typically found in treated water environments are summarized in Section 3.0 of this appendix.

1.3.3 Raw Water

At ANO-1, raw water systems use water from Lake Dardanelle that has been filtered by traveling water screens. In addition, the floor drains and reactor building and auxiliary building sumps may be exposed to a variety of untreated water that is classified as raw water for the determination of aging effects. Aging effects for materials typically found in raw water environments are summarized in Section 4.0 of this appendix.

1.3.4 Sodium Hydroxide

The sodium hydroxide (chemical addition) system contains sodium hydroxide in demineralized water. Aging effects for materials typically found in a sodium hydroxide environment are summarized in Section 5.0 of this appendix.

1.3.5 Lubricating Oil and Fuel Oil

The lubricating oil and fuel oil environment is applicable to components holding or using oil lubricants or fuel oil. Lubricating oil is low to medium viscosity hydrocarbons used for bearing, gear, and engine lubricating. Fuel oil is defined as diesel oil, No. 2 oil or other liquid hydrocarbons used to fuel diesel engines. Aging effects for materials found in an oil or fuel oil environment are summarized in Section 6.0 of this appendix.

1.3.6 Gas

Section 7.0 of this appendix discusses the aging effects applicable to the materials exposed to internal environments consisting of various gases. Non-Class 1 mechanical components within the scope of license renewal are exposed to the following internal gas environments.

- Air – both at atmospheric pressure in ventilation systems and compressed air used as a working fluid, e.g., instrument air
- Nitrogen
- Carbon dioxide
- Freon
- Halon

Ventilation, halon, compressed air, and refrigeration systems contain an internal environment of gas as the process fluid. Other systems only have an internal environment of gas above the liquid level in storage tanks or in portions of the system that are normally open to the atmosphere.

1.3.7 External Surface Environments

Sections 2.0 through 7.0 of this appendix discuss the aging effects of various fluids on the internal surfaces of components that ordinarily contain those fluids. Component external surfaces may experience aging due to exposure to the environment. Applicable external environments include the ambient atmosphere (including airborne contaminants and moisture), leakage, and the underground environment. Aging effects for materials exposed to these environments are discussed in Section 8.0 of this appendix. Degradation of external surfaces of bolted closures is addressed in Section 9.0 of this appendix.

1.3.8 Bolted Closures

Bolting applications within the scope of license renewal may be divided into pressure boundary bolting and structural or component support bolting. Pressure boundary bolting applications, which are addressed in Section 9.0 of this appendix, include bolted flange connections for vessels (i.e., manways and inspection ports), flanged joints in piping, body-to-bonnet joints in valves, and pressure retaining bolting associated with pumps and miscellaneous process components. These bolted joints are hereafter referred to as bolted closures. A bolted closure includes the entire bolted joint, seating surfaces (e.g., flange set surfaces), gasket, and pressure retaining bolting. Aging mechanisms affecting bolted closure integrity for the pressure boundary intended function are discussed in Section 9.0 of this appendix.

1.3.9 Heat Exchangers

Section 10.0 of this appendix discusses the aging effects applicable to heat exchangers.

1.4 POTENTIAL AGING EFFECTS

Potential aging effects are considered applicable if the effects could cause a component to lose function during the period of extended operation. The potential aging effects for non-Class 1 mechanical system components are as follows.

Loss of Material

Loss of material may be due to general corrosion, pitting corrosion, boric acid wastage, galvanic corrosion, crevice corrosion, erosion (including erosion caused by abrasive wear, erosive wear, cavitation wear, and droplet impingement wear), erosion/corrosion, microbiologically influenced corrosion, or selective leaching.

General corrosion is the result of a chemical or electrochemical reaction between the material and the environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup. General corrosion on components exposed to air tends to form a protective oxide film on the component that prevents further significant corrosion. This is typically true for components not exposed to other sources of moisture such as rain, condensation, or frequent leakage.

Pitting corrosion is a form of localized attack that results in depressions in the metal. Oxygen is required for initiation of pitting corrosion with contaminants such as halogens or sulfates required for continued material dissolution. Pitting corrosion is more common with passive materials such as austenitic stainless steels than with non-passive materials. Most materials of interest are susceptible to pitting corrosion under certain conditions. Most pitting is associated with the presence of halide ions, chlorides, bromides, and hypochlorites.

Loss of material due to boric acid wastage is an applicable aging effect for the external surfaces of carbon steel and low-alloy or chrome-molly component materials exposed to the leakage of borated water. Leaking fluid from a borated water system may expose the external surfaces of components made from these materials to a concentrated boric acid solution that can cause loss of material.

Loss of material due to galvanic corrosion can occur only when materials with different electrochemical potentials are in contact in the presence of oxygenated water or a corrosive environment. Generally, the effects of galvanic corrosion are precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). In galvanic couples involving admiralty, brass, carbon steel, cast iron, copper, low-alloy steel and stainless steel materials, the lower potential (more anodic) carbon steel, cast iron and low-alloy steel materials would be preferentially attacked.

Crevice corrosion occurs when a crevice exists in a component that allows a corrosive environment to develop within the crevice. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads. Crevice corrosion is strongly dependent on the presence of dissolved oxygen. Oxygen is required for crevice corrosion initiation; however, once initiated, the corrosion process does not require oxygen to continue. For environments with extremely low oxygen content (<0.1 ppm), crevice corrosion is considered insignificant.

Erosion-corrosion is a term used to describe the alternating pattern of oxide erosion due to fluid flow followed by corrosion of the newly exposed material surface that is again followed by oxide erosion as the pattern repeats. Physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, and mechanical component configuration affect the degree of erosion-corrosion.

Microbiologically influenced corrosion is a localized, corrosive attack accelerated by the influence of microbiological activity. Microbiologically influenced corrosion usually occurs at temperatures between 50°F and 120°F. Microbiological organisms can produce corrosive substances, as a byproduct of their biological processes, that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion.

Selective leaching is the dissolution of one element from a solid alloy by corrosion processes.

Cracking

Cracking is service-induced cracking (initiation and growth) of base metal or weld metal due to hydrogen damage, stress corrosion, intergranular attack, or vibration. The analysis of the potential for cracking due to low cycle, thermal fatigue is a time-limited aging analysis and is addressed in the ANO-1 LRA.

Hydrogen damage to carbon steel results from the absorption of hydrogen into the metal. This effect is prevalent in carbon steel only for very high yield strengths that are not utilized in the non-Class 1 components at ANO-1.

Stress corrosion cracking and intergranular attack require a combination of a susceptible material, a corrosive environment, and tensile stress. Since the level of tensile stress required for stress corrosion cracking in a component is unknown, the stresses are conservatively assumed to be sufficient to initiate stress corrosion cracking and intergranular attack if the other conditions are met. Intergranular attack is similar to stress corrosion cracking, except that stress is not necessary for it to proceed. In the case of stress corrosion cracking of carbon and low-alloy steels, the literature shows the mechanism is possible citing stress corrosion cracking in aqueous chlorides as the most common form. However, in the discussion of prevention and control, one of the most reliable methods of preventing stress corrosion cracking of carbon and low-alloy steels is to select a material with a yield strength of less than 100 ksi. The yield strength of carbon steels typically used in non-Class 1 systems is on the order of 30 to 45 ksi. Industry data does not indicate a significant problem of stress corrosion cracking in low strength carbon steels. For these reasons, stress corrosion cracking of carbon and low-alloy steels is considered not applicable.

For stainless steels exposed to atmospheric conditions, stress corrosion cracking is considered plausible when exposed to high levels of contaminants (e.g., saltwater environment) and only if the material is in a sensitized condition. For ANO-1 non-Class 1 mechanical systems, this applies only to components whose exterior surfaces may be exposed to sodium hydroxide.

Stainless steel components at ANO-1 that are exposed to high levels of chlorides, fluorides, or sulfates have been reviewed for susceptibility to cracking from stress corrosion cracking. Cracking has been identified as an applicable aging effect at ANO-1 for stainless steel components that are exposed to high levels of chlorides, fluorides, or sulfates. ANO has not experienced cracking of the low carbon stainless steel components exposed to water from Lake Dardanelle. Low carbon stainless steel in an environment of low temperature water has a reduced susceptibility to cracking. This is consistent with NPRDS industry failure data that indicates stress corrosion cracking of stainless steels in a fresh water lake water environment is unlikely.

<u>Change in Material Properties</u>

Change in material properties is a reduction in fracture toughness due to hydrogen embrittlement, radiation embrittlement, or thermal aging. Change in material properties was considered in all mechanical system components falling within the scope of license renewal. For non-Class 1 mechanical system components, change in material properties is not an applicable aging effect.

<u>Distortion</u>

Distortion is a physical property change in a component caused by plastic deformation due to the temperature-related phenomenon of creep. Materials within non-Class 1 components are not exposed to the required high temperatures necessary for this mechanism to occur. Therefore, distortion is not an applicable aging effect for the non-Class 1 mechanical system components at ANO-1.

<u>Loss of Mechanical Closure Integrity</u>

The loss of mechanical closure integrity is an aging effect resulting in failure of a mechanical closure to provide a required pressure boundary. Loss of mechanical closure integrity may be attributed to one or more of the following conditions affecting bolting material.

- Loss of pre-load
- Cracking of bolting material
- Loss of bolting material
- Reduction of fracture toughness of bolting material (only applicable to reactor coolant system components)

<u>Fouling</u>

Fouling may be due to macro-organisms, precipitation or silting. Fouling is not a material degradation phenomenon, but is an aging effect that could cause loss of the heat transfer intended function, or a reduction in flow rate, for components in ANO-1 systems.

1.5 SECTION 1.0 REFERENCES

1-1 BAW-2244A, "*Demonstration of the Management of Aging Effects for the Pressurizer*," The B&W Owners Group Generic License Renewal Program, December 1997

1-2 "*Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers*," SAND93-7070, prepared by MDC-Ogden Environmental and Energy Services under contract to Sandia National Laboratories for the U.S. Department of Energy, June 1994.

2.0 EFFECTS REQUIRING AGING MANAGEMENT IN BORATED WATER ENVIRONMENTS

2.1 ATTRIBUTES OF BORATED WATER ENVIRONMENTS

Borated water is demineralized water with varying concentrations of boric acid.

2.2 MATERIALS USED IN BORATED WATER ENVIRONMENTS

The majority of the components within the scope of license renewal exposed to internal borated water are constructed of stainless steel. Other components are constructed of carbon steel but lined with stainless steel or Plastite to protect the carbon steel from direct contact with the borated water. Materials in direct contact with borated water include stainless steels and inconel.

2.3 AGING EFFECTS IN BORATED WATER ENVIRONMENTS

2.3.1 Loss of Material

Loss of material due to pitting corrosion is an applicable aging effect for inconel and stainless steel in borated water under certain conditions. For a borated water environment, two sets of conditions can lead to pitting corrosion. The first set of conditions needed for pitting corrosion to occur is the presence of halogens in excess of 150ppb, oxygen in excess of 100ppb and stagnant or low flow conditions. A second set of conditions leading to pitting corrosion is the presence of sulfates in excess of 100ppb, oxygen in excess of 100ppb and stagnant or low flow conditions. If either set of conditions is satisfied, loss of material due to pitting corrosion is an applicable aging effect for inconel and stainless steel materials in borated water.

2.3.2 Cracking

Cracking due to stress corrosion and intergranular attack of inconel and stainless steel materials in a borated water environment is an applicable aging effect under certain conditions. For inconel and stainless steel, the relevant conditions required for stress corrosion cracking are the presence of halogens in excess of 150ppb or sulfates in excess of 150ppb. In addition, stress corrosion cracking has been observed in high-purity water (i.e., sulfates and halogens less than 150ppb) at temperatures greater that 200°F with dissolved oxygen levels greater than 100ppb.

2.4 INDUSTRY EXPERIENCE IN BORATED WATER ENVIRONMENTS

In order to validate the applicable aging effects for components exposed to borated water, industry experience was reviewed. The review included an NPRDS search on relevant topics and NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those described in this section.

3.0 EFFECTS REQUIRING AGING MANAGEMENT IN TREATED WATER ENVIRONMENTS

3.1 ATTRIBUTES OF TREATED WATER ENVIRONMENTS

Treated water is demineralized water and is the base water for all clean systems. Depending on the system, treated water may require additional processing. Treated water could be deaerated, include corrosion inhibitors, biocides, or some combination of these treatments. In the determination of aging effects, steam is considered treated water.

Water chemistry of the main feedwater system is closely monitored to minimize the potential for degradation of the once-through steam generators. The pH of the feedwater is maintained by the addition of amines to reduce the potential for flow-assisted corrosion by reducing iron transport. Deaeration and the addition of hydrazine control dissolved oxygen. Impurities such as chlorides and sulfates are controlled to reduce the stress corrosion cracking of OTSG tubes.

Chemistry requirements for the demineralized or makeup water are stringent since makeup water is used for reactor coolant, secondary, and other auxiliary systems in which high quality water is required.

Emergency feedwater systems and condensate systems have strict limit on contaminants, but the safety related condensate storage tank at ANO-1 is vented to atmosphere so these systems contain water saturated with oxygen.

The chemistry in the auxiliary systems is treated water with corrosion inhibitors.

3.2 MATERIALS USED IN TREATED WATER ENVIRONMENTS

The following materials are exposed to an internal treated water environment.

- Stainless steels
- Carbon and low alloy (chrome-moly) steels
- Cast iron
- 90/10 Cu-Ni
- Copper
- Brass
- Bronze
- Admiralty
- Glass

3.3 Aging Effects in Treated Water Environments

3.3.1 Loss of Material

Loss of material due to general corrosion is an applicable aging effect for admiralty, brass, carbon steel, cast iron, copper, and low-alloy steel in ANO-1 treated water environments due to the presence of oxygen. Stainless steel in treated water environments is resistant to general corrosion.

Loss of material due to pitting corrosion is an applicable aging effect for admiralty, brass, carbon steel, cast iron, copper, low-alloy steel, and stainless steel materials in a treated water environment under certain conditions. For a treated water environment, two sets of conditions can lead to pitting corrosion. The first set of conditions is the presence of halogens in excess of 150ppb, oxygen in excess of 100ppb and stagnant or low flow conditions. A second set of conditions is the presence of sulfates in excess of 150ppb, oxygen in excess of 100ppb and stagnant or low flow conditions.

Loss of material due to galvanic corrosion can occur only when materials with different electrochemical potentials are in contact in the presence of oxygenated water.

Loss of material due to erosion-corrosion is an applicable aging effect for carbon steel in treated water under certain conditions. Fluid conditions in the main steam and main feedwater systems can lead to erosion-corrosion.

3.3.2 Cracking

Cracking due to stress corrosion of stainless steel materials in treated water is an applicable aging effect under certain conditions. For stress corrosion cracking to occur in stainless steel, the concentration of halogens or sulfates must exceed 150ppb. In addition, stress corrosion cracking of stainless steel has been observed in high-purity water (i.e., sulfates and halogens less than 150ppb) at temperatures greater that 200°F with dissolved oxygen levels greater than 100ppb. If these relevant conditions are satisfied, stress corrosion cracking is an applicable aging effect for stainless steel in a treated water environment.

3.4 Industry Experience with Treated Water Environments

To validate the applicable aging effects for mechanical components exposed to a treated water internal operating environment, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those discussed in this section.

4.0 EFFECTS REQUIRING AGING MANAGEMENT IN RAW WATER ENVIRONMENTS

4.1 ATTRIBUTES OF RAW WATER ENVIRONMENTS

The majority of raw water for ANO-1 is water from Lake Dardanelle. In general, the water has been rough-filtered to remove large particles and may contain a biocide additive for control of microorganisms, zebra mussels, and Asiatic clams. Lake Dardanelle is considered fresh water, i.e., it has a sodium chloride content below 1000 mg/l. In addition, the floor drains and reactor building and auxiliary building sumps may be exposed to a variety of untreated water that is classified as raw water for the determination of aging effects.

4.2 MATERIALS USED IN RAW WATER ENVIRONMENTS

Materials within the scope of license renewal at ANO-1 that are exposed to raw water include the following.

- Stainless steel
- Carbon and low alloy steel
- Cast iron
- Brass
- Admiralty
- Copper
- 90-10 copper nickel
- Bronze

4.3 AGING EFFECTS IN RAW WATER ENVIRONMENTS

4.3.1 Loss of Material

Loss of material due to general corrosion is an applicable aging effect for admiralty, brass, bronze, carbon steel, low alloy steel, cast iron, copper, and 90-10 copper-nickel component materials in a raw water environment. The stainless steel materials in the plant raw water environments are resistant to general corrosion.

Loss of material due to pitting corrosion is an applicable aging effect for admiralty, brass, bronze, carbon steel, low alloy steel, cast iron, copper, 90-10 copper-nickel, cast iron, and stainless steel materials in a raw water environment. Maintaining an adequate flow rate, which prevents impurities from adhering to the material surface, can inhibit pitting corrosion. The more susceptible locations for pitting corrosion in materials in a raw water environment are locations of low or stagnant flow.

Loss of material due to galvanic corrosion in a raw water environment can occur when materials with different electrochemical potentials are in contact.

Microbiological organisms present in raw water can produce corrosive substances, as a byproduct of their biological processes, that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion. Loss of material due to microbiologically influenced corrosion is an applicable aging effect for admiralty, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, and stainless steel materials exposed to raw water.

Loss of material due to selective leaching is an applicable aging effect for cast iron component materials in a raw water environment.

4.3.2 Cracking

Cracking due to stress corrosion cracking or intergranular attack is a potential concern for stainless steels and copper-based alloys in a raw water environment due to possible chemical concentrations. ANO-1 has not experienced cracking of stainless steel components exposed to service water because of the low temperature of the water and the use of low carbon stainless steel. This is consistent with NPRDS industry failure data that indicates stress corrosion cracking of stainless steels in a fresh water lake environment is not likely. Cracking has been conservatively identified as an applicable aging effect for components exposed to fluid in floor drains or sumps due to the potential for very high levels of contaminants in this environment.

4.3.3 Fouling

For a raw water system, fouling is an applicable aging effect. Fouling can be categorized by particulate fouling (sediment, silt, dust, corrosion products, etc.), marine biofouling (clamshells, mussels, etc.) or macro fouling (peeled coatings, debris, etc.). Fouling in a raw water system can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of the function of heat transfer and a reduction in the system flow rate.

4.4 Industry Experience with Raw Water Environments

To validate the applicable aging effects for mechanical components exposed to a raw water internal operating environment, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those discussed in this section.

5.0 EFFECTS REQUIRING AGING MANAGEMENT IN SODIUM HYDROXIDE ENVIRONMENTS

5.1 ATTRIBUTES OF SODIUM HYDROXIDE ENVIRONMENTS

Sodium hydroxide solutions in demineralized water are used in the sodium hydroxide (chemical addition) system to mix with the reactor building spray during loss of coolant accidents. The sodium hydroxide system is supplied only from treated water that is free from microorganisms. Microbiologically influenced corrosion has not occurred in this system. The sodium hydroxide in the system is a caustic soda that is maintained at a concentration of 18 +2.8/-3.0 wt.% as required by the ANO-1 Technical Specifications. High levels of chlorides exist in sodium hydroxide solutions due to the production methods for the sodium hydroxide. Since the tank is vented to the atmosphere, oxygen levels of the tank contents are expected to be near saturation.

5.2 MATERIALS USED IN SODIUM HYDROXIDE ENVIRONMENTS

The materials exposed to sodium hydroxide solution within the scope of license renewal include stainless steels and carbon and low alloy steels.

5.3 AGING EFFECTS IN SODIUM HYDROXIDE ENVIRONMENTS

5.3.1 Loss of Material

Carbon and low alloy steel are susceptible to general corrosion in a sodium hydroxide solution. Carbon and low alloy steels exposed to sodium hydroxide will form a protective film and further corrosion of the carbon steel is greatly affected by the liquid agitation and the temperature. Pitting and crevice corrosion are applicable aging mechanisms for carbon and low alloy steel due to the low flow and high chlorides. Galvanic corrosion is an applicable mechanism for carbon and low alloy steel at the interfaces with the stainless steel piping.

The corrosion rate of stainless steel in sodium hydroxide solutions at low temperatures is expected to be less than 0.1 mil per year, which will not cause significant loss of material even in the period of extended operation. Pitting and crevice corrosion are applicable aging mechanisms due to the stagnant conditions and high levels of chlorides.

5.3.2 Cracking

Stress corrosion cracking and intergranular separation are applicable aging mechanisms for the stainless steel materials since the water contains high levels of chlorides.

5.4 INDUSTRY EXPERIENCE WITH SODIUM HYDROXIDE ENVIRONMENTS

To validate the applicable aging effects for mechanical components exposed to sodium hydroxide, industry experience was reviewed. The review included an NPRDS search on relevant topics and review of NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those discussed in this section.

6.0 EFFECTS REQUIRING AGING MANAGEMENT IN LUBRICATING OIL AND FUEL OIL ENVIRONMENTS

6.1 ATTRIBUTES OF LUBRICATING OIL AND FUEL OIL ENVIRONMENTS

Separate evaluations are completed for lubricating oil and fuel oil.

6.1.1 Fuel Oils

At ANO-1, the fuel oil within the scope of licensing renewal is primarily No. 2 diesel oil. Diesel fuel oil is delivered to ANO-1 in tanker trucks and is stored in large tanks to provide an on-site supply of diesel fuel for a specified period of diesel generator operating time. This fuel oil is supplied to the diesel engines through pumps, valves, and piping. Strainers, filters and other equipment assure that the diesel fuel supplied to the engines is clean and free of contaminants.

6.1.2 Lubricating Oils

Lubricating oils within the scope of license renewal are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubricating.

6.2 MATERIALS USED IN LUBRICATING OIL AND FUEL OIL ENVIRONMENTS

The non-Class 1 mechanical components within the scope of license renewal exposed to lubricating oil and fuel oils contain the following materials.

- Stainless steels
- Carbon and low alloy steels
- Cast iron
- Brass
- Bronze
- Aluminum
- Admiralty
- Glass
- Copper

6.3 AGING EFFECTS IN THE LUBRICATING OIL AND FUEL OIL ENVIRONMENTS

6.3.1 Fuel Oil Environment

Loss of material due to general corrosion is an applicable aging effect for carbon and low alloy steel in a fuel oil environment at locations containing water. The stainless steel, brass, admiralty, cast iron, glass, aluminum, bronze, and copper are inherently resistant to general corrosion in the plant fuel oil environments.

Loss of material due to pitting corrosion is an applicable aging effect for brass, bronze, carbon steel, low alloy steel, copper, and stainless steel materials in a fuel oil environment at location containing oxygenated water and contaminants such as halide ions, particularly chloride ions.

Loss of material due to crevice corrosion is an applicable aging effect for brass, bronze, carbon steel, copper, and stainless steel materials in a fuel oil environment at locations containing oxygenated water. Oxygen is required for the initiation of crevice corrosion. Fuel oil that is not contaminated does not contain oxygen in sufficient quantities for crevice corrosion to occur. Water contamination of the fuel oil is required for the introduction of oxygen.

Loss of material due to galvanic corrosion in a fuel oil environment can occur only when materials with different electrochemical potentials are in contact in the presence of water.

Loss of material due to microbiologically influenced corrosion is an applicable aging effect for brass, carbon steel, copper, and stainless steel materials exposed to fuel oil if microorganisms are present.

Cracking due to stress corrosion of the stainless steel material in a fuel oil environment is an applicable aging effect at locations containing oxygenated water.

Due to the high quality of fuel oil received at ANO-1, the system configuration, and sampling performed, little water is expected in the fuel oil systems. Any significant amount of water contamination would accumulate at the bottoms of the tanks, due to the higher density of water relative to fuel oil and the relatively low flow velocities in large tanks. Due to the addition of biocides, microbiologically influenced corrosion is not a concern for the ANO-1 fuel oil.

6.3.2 Lubricating Oil Environment

Loss of material due to general corrosion is an applicable aging effect for carbon and low alloy steel in a lubricating oil environment at locations containing water. The stainless steel, brass, admiralty, cast iron, glass, aluminum, bronze, and copper in the plant lubricating oil environments are inherently resistant to general corrosion.

Loss of material due to pitting corrosion is an applicable aging effect for brass, bronze, carbon steel, low alloy steel, copper, and stainless steel materials in a lubricating oil environment at location containing oxygenated water with contaminants such as halide ions, particularly chloride ions.

Loss of material due to crevice corrosion is an applicable aging effect for brass, bronze, carbon steel, copper, and stainless steel materials in an oil environment at locations containing oxygenated water. Oxygen is required for the initiation of crevice corrosion. Lube oil does not contain oxygen in sufficient quantities for crevice corrosion to occur. Water contamination of the lubricating oil is required for the introduction of oxygen.

Loss of material due to galvanic corrosion in a lubricating oil environment can occur only when materials with different electrochemical potentials are in contact in the presence of water.

Loss of material due to microbiologically influenced corrosion is an applicable aging effect for brass, carbon steel, copper, and stainless steel materials exposed to lubricating oil.

Cracking due to stress corrosion of the stainless steel material in a lubricating oil environment is an applicable aging effect at locations containing oxygenated water.

Due to the high quality of lubricating oil received at ANO-1 and the periodic sampling performed, water or contaminants are not expected in the lubricating oil systems. Microbiologically influenced corrosion has not been a concern for the ANO-1 lubricating oil for the systems in the scope of license renewal.

6.4 Industry Experience with Lubricating Oil and Fuel Oil Environments

To validate the applicable aging effects for mechanical components exposed to lubricating oil or fuel oil internal operating environment, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those discussed in this section.

7.0 EFFECTS REQUIRING AGING MANAGEMENT IN GAS ENVIRONMENTS

The gas environments within the scope of license renewal at ANO-1 include atmospheric air (filtered and unfiltered), instrument air (clean and dry), and compressed gases (nitrogen, carbon dioxide, freon, and halon). A steam environment is considered a treated water environment as discussed in Section 3.0 of this appendix.

7.1 ATTRIBUTES OF GAS ENVIRONMENTS

This discussion includes a majority of the gaseous internal environments to which components within the scope of license renewal may be subjected. Numerous components may be subjected to different gaseous environments depending on plant and system operating conditions. The various gaseous environments covered by this discussion are described below.

7.1.1 Air

Air is composed of mostly nitrogen and oxygen with smaller fractions of various other constituents. The internal surfaces of a majority of components are at some time exposed to air. External surface contact with air is described in Section 8.0 of this appendix. Where air is the intended internal fluid (e.g., compressed air and instrument air systems), it is supplied in either its natural state or in a "dry" condition. The ANO instrument air system supplies air free of water or contaminants.

7.1.2 Nitrogen

Nitrogen is an inert gas used in many nuclear plant applications to place components in a dry lay-up condition or to provide a cover gas to prevent exposure to oxygen. The commercial grade nitrogen provided to ANO-1 is a high quality product with little, if any, contaminants.

7.1.3 Carbon Dioxide

Carbon dioxide is a colorless, odorless incombustible gas. The carbon dioxide systems of interest at ANO-1 contain dry carbon dioxide in gaseous form. Without the presence of moisture, this gaseous carbon dioxide is not a significant contributor to corrosion or other aging effects.

7.1.4 Freon

Fluorocarbons constitute a large family of fluorinated hydrocarbon compounds that exhibit similar chemical properties and a wide range of physical characteristics. The fluorocarbons used at ANO-1 are inert, nonflammable, colorless and relatively nontoxic. Their inert character and the range of their vapor pressures, boiling points and other physical properties makes them especially well suited for use as the working fluid in refrigeration and air conditioning systems.

7.1.5 Halon

Halon 1301 (bromotrifluoromethane-CF_3Br) is a halogenated extinguishing agent used in the ANO-1 main control room fire system for its ability to chemically react with fire and smother flames. The high purity Halon supplied to ANO-1 is essentially a non-corrosive gas. In use, it is combined with nitrogen gas (used as a propellant) in the fire suppression system.

7.2 Materials Used in Gaseous Environments

The materials exposed to gases within the scope of license renewal include the following.

- Stainless steels
- Carbon and low alloy steels
- Cast iron
- Brass
- Bronze
- Aluminum
- 90-10 copper nickel
- Copper
- Admiralty

7.3 Aging Effects in Gaseous Environments

For the most part, gases provide an environment for aging effects only in the presence of moisture or other contaminants.

7.3.1 Aging Effects in Air Environments

General Corrosion

At ordinary temperatures, oxygen and moisture are the basic factors for the corrosion of iron. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any significant extent. Carbon and low-alloy steels, as well as cast iron are susceptible to general corrosion. Stainless steels, nickel-based alloys, aluminum, copper alloys and galvanized steel are inherently resistant to general corrosion.

General corrosion is an electrolytic reaction and, regardless of the particular gas environment, depends on the presence of oxygen and moisture. Corrosion in a nonaqueous environment only occurs by direct chemical reaction and only at high temperatures well above those encountered at ANO-1. Nitrogen and halon environments should have negligible amounts of free oxygen. Therefore, corrosion of carbon steel and cast iron components in these environments should not be a concern. The air environments within plant systems and components can vary from clean, dry air to moist, contaminated air whose purity is dictated by the source of the air. Portions of compressed air systems contain air that has been processed through dryers, which provide dry, oil free air to the downstream portions of the system. Moisture should not be a concern for these portions of systems and general corrosion is not expected.

Galvanic Corrosion

The severity of galvanic corrosion depends largely on the type and amount of moisture present. Galvanic corrosion does not occur when the metals are completely dry since there is no electrolyte to carry the current between the two electrode areas. Any gas and moisture interface that contains dissimilar materials with significant potential differences may be susceptible to galvanic corrosion. Air systems can be susceptible to galvanic corrosion due to the different materials used and the potential for moisture in crevices and other low points of systems. Aluminum to brass connections, as well as steel to copper connections, are susceptible to galvanic corrosion.

Crevice Corrosion

With any gas environment other than air, the oxygen content may be low enough to preclude crevice corrosion concerns. Crevice corrosion is a concern where moisture may pool in the presence of contaminants such as halides or sulfates.

Pitting Corrosion

All ANO-1 materials of interest are susceptible to pitting corrosion under certain conditions. Most pitting is associated with the presence of halide ions, chlorides, bromides, or hypochlorites.

Microbiologically Influenced Corrosion

Microbiological organisms that could induce corrosion are generally not found in a gaseous environment. Microbiologically influenced corrosion, therefore, is only a potential problem where contamination from untreated water or soil may have introduced bacteria. Air and gas systems are only affected where stagnant conditions and the pooling of an untreated aqueous solution provide an environment suitable for propagation of the mechanism.

7.3.2 Aging Effects in Nitrogen Environments

Carbon steel, cast iron and stainless steel in a nitrogen environment have no aging effects since the nitrogen has negligible amounts of free oxygen.

7.3.3 Aging Effects in Carbon Dioxide Environments

Carbon dioxide environments should have negligible amounts of free oxygen; therefore, corrosion of carbon steel and cast iron components in these environments should not be a concern.

7.3.4 Aging Effects in Freon Environments

Fluorocarbons show no appreciable decomposition at temperatures up to 400°F and oxidize only at very high temperatures. Fluorocarbons are non-corrosive to common metals except at very high temperatures.

The ANO-1 non-Class 1 refrigerant systems are typically pressurized closed loop systems containing freon mixed with an oil lubricant. These systems contain in line refrigerant dryers for enhancement of both performance and corrosion prevention. Unless contamination of the closed system with moisture or sulfur occurs, the conditions necessary for internal pressure boundary degradation due to corrosion do not exist.

7.3.5 Aging Effects in Halon Environments

The Halon environment is non-corrosive for the materials in the Halon system.

7.4 Industry Experience with Gaseous Environments

To validate the applicable aging effects for mechanical components exposed to an internal gaseous operating environment, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified from these documents beyond those discussed in this section.

8.0 EFFECTS REQUIRING AGING MANAGEMENT IN EXTERNAL SURFACE ENVIRONMENTS

The purpose of this section is to identify aging effects applicable for external surfaces of mechanical components at ANO-1. Sections 2.0 through 7.0 of this appendix focused on specific material and internal environment combinations and the associated aging effects. Degradation of external surfaces of bolted closures is addressed in Section 9.0 of this appendix. External environments include the ambient atmosphere, leakage, and the underground environment.

8.1 ATTRIBUTES OF EXTERNAL SURFACE ENVIRONMENTS

8.1.1 External Ambient Environment

The external ambient environment consists of atmospheric conditions, which may include humidity, condensation, and airborne contaminants such as sulfur dioxide, chlorine gas, sulfur gas, and ozone.

8.1.2 Leakage Environment

The leakage environment is created when fluids escape from their system boundaries (usually from bolted closures) and contact the external surfaces of components. The fluid in leakage environments of concern is typically borated, treated, or raw water.

8.1.3 Underground Environment

The underground environment applies to components buried in the soil and exposed to the soil and groundwater. The soil and groundwater are untreated and could be corrosive to materials. The factors affecting corrosiveness of soils are moisture, pH (alkalinity or acidity), permeability of water and air (compactness or texture), oxygen, salts, stray currents, and biological organisms. Most of these affect electrical resistance of the soil, which is a good measure of corrosivity. High-resistance dry soils are generally not very corrosive. Carbon steel and cast iron with organic coatings are most common for underground components. Buried components are assumed susceptible to corrosion due to the potential for exposure to oxygen, moisture, biological organisms, and contaminants.

8.2 Materials Exposed to External Surface Environments

The materials exposed to external environments include the following.

- Stainless steels
- Carbon and low alloy (chrome-moly)steel
- Cast iron
- Brass
- Bronze
- 90/10 Cu-Ni
- Incoloy-800
- Aluminum
- Copper
- Admiralty
- Glass

8.3 Aging Effects of the External ambient Environment

8.3.1 Loss of Material

Loss of material due to general corrosion is an applicable aging effect for carbon steel and low-alloy steel, admiralty, brass, cast iron, and copper materials in ambient air environments if the material is in contact with moist air. Paint or protective coatings applied to external surfaces will prevent this aging effect.

Loss of material due to galvanic corrosion can occur when materials with different electrochemical potentials are in contact in the presence of water, which is needed to establish the galvanic couple. Systems continually operating at a temperature at which surface condensation occurs in the ambient air environment will have water present on their external surfaces.

8.3.2 Cracking

Stress Corrosion Cracking/Intergranular Attack

One of the most reliable methods of preventing stress corrosion cracking of carbon and low-alloy steels is to select a material with yield strength of less than 100 ksi. The yield strength of carbon steels typically used in non-Class 1 systems is on the order of 30 to 45 ksi. Industry data does not indicate a problem of stress corrosion cracking in low strength carbon steels. For these reasons, stress corrosion cracking of carbon and low-alloy steels is considered not applicable.

For stainless steels exposed to atmospheric conditions, stress corrosion cracking is only plausible when exposed to high levels of contaminants (e.g., saltwater environment) and then only if the material is in a sensitized condition.

8.4 Aging Effects in Leakage Environments

8.4.1 Loss of Material

Borated Water Leakage

Loss of material due to boric acid wastage is an applicable aging effect for the external surfaces of carbon steel and low-alloy or chrome-moly materials exposed to leakage of borated water. Leaking fluid from a borated water system may expose the external surfaces of components made from these materials to a concentrated boric acid solution that can cause loss of material.

Treated Water Leakage

Loss of material due to general corrosion is an applicable aging effect for admiralty brass, brass, carbon steel, cast iron, copper, and low-alloy steel exposed to treated water leakage due to the presence of oxygen. Stainless steel materials exposed to treated water leakage are resistant to general corrosion. Paint or protective coatings applied to external surfaces will prevent this aging effect.

Loss of material due to pitting corrosion is an applicable aging effect for admiralty brass, brass, carbon steel, cast iron, copper, low-alloy steel, and stainless steel materials exposed to treated water leakage. Paint or protective coatings applied to external surfaces will prevent this aging effect.

Raw Water Leakage

Loss of material due to general corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, and 90-10 copper-nickel component materials exposed to raw water leakage. Stainless steel materials are resistant to general corrosion due to raw water leakage.

Loss of material due to pitting corrosion is an applicable aging effect for admiralty, brass, bronze carbon steel, cast iron, copper, 90-10 copper-nickel, and stainless steel materials exposed to raw water leakage.

Loss of material due to galvanic corrosion can occur in materials exposed to raw water leakage.

Loss of material due to microbiologically influenced corrosion is an applicable aging effect for admiralty, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel and stainless steel materials exposed to raw water leakage.

Paint or protective coatings applied to external surfaces will prevent exposure to the raw water environment eliminating the aging effect of loss of material.

8.5 Aging Effects of Underground Environments

8.5.1 Loss of Material

Carbon steel materials in the underground environment in contact with soil and untreated groundwater can experience loss of material due to various corrosion mechanisms.

Microbiological organisms present in the soil or groundwater can produce corrosive substances, as a byproduct of their biological processes, that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion.

Galvanic corrosion in an underground environment can occur when materials with different electrochemical potentials are in contact in the presence of water. In the underground environment, galvanic corrosion can occur between the material and the surrounding soil and groundwater.

8.6 Industry Experience with External Aging Effects

To validate the applicable aging effects for mechanical components exposed to various external environments, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified from these documents beyond those discussed in this section.

9.0 EFFECTS REQUIRING AGING MANAGEMENT FOR BOLTED CLOSURES

This section discusses aging affects applicable to bolted closures of non-Class 1 mechanical components whose intended function is maintenance of pressure boundaries including the following.

- Bolted flange connections for vessels (i.e., manways and inspection ports)
- Flanged joints in piping
- Body-to-bonnet joints in valves
- Pressure-retaining bolting on pumps and miscellaneous process components

A bolted closure includes the seating surfaces (e.g., flange set surfaces), gasket, and pressure retaining bolting. Pressure boundary bolting, typically referred to as threaded fasteners, includes nuts, bolts, studs, and capscrews. Gaskets do not require an aging management review because the gaskets are only a part of the bolted connection and exist to minimize leakage rather than to directly support the pressure boundary.

9.1 ATTRIBUTES OF BOLTED CLOSURE ENVIRONMENTS

Bolted closures within the scope of license renewal are found in all non-Class 1 mechanical systems. The non-Class 1 bolting and threaded connections are subject to external ambient environments and exposure to leakage of process fluids from within components.

9.2 MATERIALS EVALUATED FOR BOLTING/THREADED CONNECTIONS

The materials used in bolting and threaded connections within the scope of license renewal are primarily carbon and low-alloy steels and stainless steel.

9.3 AGING EFFECTS ON BOLTED CLOSURES

The governing aging effect to consider for bolted closures is loss of mechanical closure integrity. Loss of mechanical closure integrity may be attributed to one or more of the following conditions.

9.3.1 Loss of Pre-Load

The loss of bolted closure may be attributed to embedment, cyclic load embedment, gasket creep, thermal effects (e.g., yield stress effect, modulus of elasticity effect, and stress relaxation), and self loosening.

9.3.2 Loss of Material of Bolting Materials

Corrosion of Bolting Materials

Loss of material due to boric acid wastage is the most common aging effect observed for ferritic fasteners. Stainless steel fasteners are immune to loss of material due to general corrosion. Most bolting is normally in a dry environment and is coated with a lubricant and general corrosion is not expected. General corrosion of ferritic fasteners has only been observed due to leaking joints.

Wear of Bolting Materials

Wear could lead to the loss of bolting material in connections subject to frequent operational use. Proper maintenance and tool handling practices and infrequent opening and closing preclude significant wear on most bolted connections.

9.3.3 Cracking of Bolting Materials

Cracking of bolting materials may be caused by stress corrosion cracking or fatigue. Stress corrosion cracking may occur in bolting materials subjected to water or steam (e.g., from leakage) that contains various contaminants. When leakage is combined with contaminant species, such as sulfides or chlorides, an aggressive environment that can promote stress corrosion cracking may result.

9.3.4 Vibration-Induced Loosening

Threaded connections are assumed subject to loss of mechanical closure integrity in high vibration applications, such as on diesel generators. This mechanism is independent of material and environment.

9.4 Industry Experience with Bolted Closures

To validate the applicable aging effects for non-Class 1 bolted closures, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and a review of NRC generic communications and NUREG documents. No unique aging effects were identified from these documents beyond those discussed in this section.

10.0 AGING EFFECTS REQUIRING MANAGEMENT IN HEAT EXCHANGERS

Although most heat exchanger aging effects are material and environment driven, heat exchangers are also evaluated for the component specific mechanisms of erosion and wear. In addition, heat exchangers are typically exposed to several different environment and material combinations (i.e., tube material and fluid are different from shell material and fluid) [Reference 10-1].

10.1 ATTRIBUTES OF HEAT EXCHANGER ENVIRONMENTS

The internal environments of heat exchangers (both the internal surfaces of the tubes and the internal surfaces of the shells) are the same as those described for the contained fluids (i.e., borated, raw and treated water, oil or fuel oil, and various gases). External heat exchanger surfaces are exposed to the external ambient atmosphere or to external leakage as discussed in Section 8.0 of this appendix.

10.2 HEAT EXCHANGER AGING EFFECTS

In general, heat exchanger components are subject to the same aging mechanisms as other non-Class 1 mechanical components of similar materials exposed to similar environments as described in Sections 2.0 through 8.0 of this appendix. This section will focus on the aging mechanisms that affect the heat exchangers in addition to the standard material and environment mechanisms.

10.2.1 Loss of Material

Loss of material due to vibration and rubbing of the heat exchanger internal components is an effect for heat exchangers. The applicability of this mechanism is dependent on the heat exchanger configuration.

Depending on specific component geometry and contents of the entrained fluids, erosion or erosion-corrosion can also produce a loss of material on internal heat exchanger surfaces with high flow velocities (typically, where the velocity is high in a localized area).

10.2.2 Fouling

Fouling is any process that changes heat transfer surfaces such that it impairs heat transfer. The impairment is primarily from a decrease in the heat transfer coefficient of the heat transfer surface.

Entrained materials in the fluids precipitating out and adhering to the heat exchanger surfaces, influenced by local flow patterns and temperature conditions, can cause fouling. Many corrosion mechanisms also generate corrosion byproducts that adhere to the surface of the corroding metal. Since even a thin layer of fouling can impact the heat transfer capability of heat exchangers, fouling is considered an applicable aging effect for non-Class 1 heat exchangers subject to an aging management review.

10.2.3 Heat Exchanger Operating History

To validate the applicable aging effects for non-Class 1 heat exchangers, industry experience was reviewed. The survey of industry experience included an NPRDS search on relevant topics and NRC generic communications and NUREG documents. No unique aging effects were identified in these documents beyond those discussed in this section.

10.3 SECTION 10.0 REFERENCES

10-1 Sandia National Laboratories, "Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers," Contractor Report No. SAND93-7070, June 1994.

Appendix D

Technical Specification Changes

The Code of Federal Regulations, 10CFR54.22, requires applicants to include any technical specification changes, or additions, necessary to manage the effects of aging during the period of extended operation as a part of the renewal application. Based on a review of the information provided in the ANO-1 LRA and Technical Specifications, no changes to the ANO-1 Technical Specifications have been identified.

Applicant's Environmental Report – Operating License Renewal Stage

Arkansas Nuclear One - Unit 1

Introduction

Set forth below is Entergy Operations' Environmental Report-Operating License Renewal Stage for Arkansas Nuclear One, Unit 1. This report was prepared in conjunction with Entergy Operations' application to the U. S. Nuclear Regulatory Commission to renew the operating license for ANO-1. In compliance with applicable NRC requirements, this ER analyzes potential environmental impacts associated with renewal of the ANO-1 license. It is designed to assist the NRC staff with the preparation of the ANO-1 specific Supplemental Environmental Impact Statement that is required for license renewal. The content of the ER complies with the requirements of 10CFR Part 51, as augmented by the NRC's "Generic Environmental Impact Statement for License Renewal of Nuclear Plants" (NUREG-1437).

Specifically, the ANO-1 ER complies with 10CFR54.23, which requires license renewal applicants to submit a supplement to the ER that complies with requirements of Subpart A of 10CFR Part 51. This report also addresses the more detailed requirements of NRC environmental regulations in 10CFR51.45 and 10CFR51.53, as well as the underlying intent of the National Environmental Policy Act, 42 U.S.C. § 4321 *et seq*. For major federal actions, the NEPA requires federal agencies to prepare a detailed statement that addresses significant environmental impacts, adverse environmental effects that cannot be avoided should the proposal be implemented, alternatives to the proposed action, and any irreversible and irretrievable commitments of resources associated with implementation of the proposed action. The information responsive to these requirements is set forth in the following sections of the ER:

Section 1.0: Purpose and Need for the Proposed Action
Section 2.0: Site and Environmental Interfaces
Section 3.0: Proposed Action
Section 4.0: Environmental Consequences of the Proposed Action
Section 5.0: Alternatives Considered
Section 6.0: Comparison of Impacts
Section 7.0: Status of Compliance

Based upon the evaluations discussed in the ER, Entergy Operations concludes that the environmental impacts associated with the renewal of the ANO-1 operating license are small. The environmental impacts from continued operation of ANO-1 are similar to those experienced during the original operating term and as evaluated in the Final Environmental Statement [Reference 1] issued in February 1973. No major plant refurbishment activities have been identified as necessary to support the continued operation of ANO-1 beyond the end of the existing operating license. Although normal plant maintenance activities may later be performed for economic and operational reasons, no significant environmental impacts associated with such activities are expected. Major refurbishment and plant maintenance activities typically receive an environmental review per ANO procedures during the planning stage for the activity.

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Attachment G	Severe Accident Mitigation Alternatives Analysis

ACRONYMS and ABBREVIATIONS

ALWR	Advanced Light Water Reactor
ADEQ	Arkansas Department of Environmental Quality
ADH	Arkansas Department of Health
AGFC	Arkansas Game and Fish Commission
ANHC	Arkansas Natural Heritage Commission
ANO	Arkansas Nuclear One
B&W	Babcock and Wilcox
BTA	Best Technology Available
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
DOE	Department of Energy
EA	Environmental Assessment
EIA	Energy Information Act
EIS	Environmental Impact Statement
EPA	U. S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ER	Environmental Report-Operating License Renewal Stage
FES	Final Environmental Statement
FWPCA	Federal Water Pollution Control Act
GEIS	Generic Environmental Impact Statement
GIS	Geographic Information System
IPE	Individual Plant Examination
ISFSI	Independent Spent Fuel Storage Installation
LOCA	Loss of Coolant Accident
MACCS	Melcor Accident Consequences Code System

MSW	Municipal Solid Waste
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NRC	U. S. Nuclear Regulatory Commission
NRR	(Office Of) Nuclear Reactor Regulation
NUREG	Nuclear Report Category
O&M	Operation and Maintenance
PV	Photovoltaic Cells
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
$PM_{2.5}$	Particulate Matter (nominal size of <2.5 microns)
RCRA	Resource Conservation and Recovery Act
SAMA	Severe Accident Mitigation Alternatives
SAMDA	Severe Accident Mitigation Design Alternative
SCR	Selective Catalytic Reduction
SHPO	State Historic Preservation Office
SO_2	Sulfur Dioxide
SRP	(NRC) Standard Review Plan
USC	United States Code

UNITS

cfs	cubic feet per second
fps	feet per second
ft	feet
ft^3	cubic feet
gpm	gallons per minute
ha	hectares
hr	hour
kg	kilograms
km	kilometer
kV	kilovolt
kW	kilowatt
mA	milliamps
MW	megawatts
MWd/MTU	megawatt day/metric ton uranium
MW(e)	megawatts, electric
MW(t)	megawatts, thermal
m	meters
m^3	cubic meters
mA	millamperes
°C	degrees celsius
°F	degrees fahrenheit

1.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

For license renewal, the NRC has adopted the following definition of purpose and need: "The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized Federal (other than NRC) decision makers." This is from Section 1.3 of the NRC Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NUREG-1437 [Reference 2].

Nuclear power plants are licensed by the NRC to operate for up to 40 years, and the licenses may be renewed [10CFR50.51] for periods up to 20 years. 10CFR54.17(c) states that "[a]n application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect." The proposed action will extend the ANO-1 operating license for a period of 20 years beyond the current operating license expiration date. The current operating license for ANO-1 expires at midnight on May 20, 2014 and would be renewed to expire at midnight on May 20, 2034.

2.0 SITE AND ENVIRONMENTAL INTERFACES

ANO is owned by Entergy Arkansas, Inc. and operated by Entergy Operations, Inc., both subsidiaries of Entergy Corporation. The site is located in southwestern Pope County, Arkansas, about 57 miles northwest of Little Rock, Arkansas, and 68 miles east of Fort Smith, Arkansas, on a peninsula formed by Lake Dardanelle as shown on Figure 2.1-1. Lake Dardanelle is part of the "Multiple-Purpose Improvement Plan for the Arkansas River" and includes the Arkansas River and the former Illinois Bayou. The town of Russellville, Arkansas is about six miles east-southeast of the site and the town of London, Arkansas is about two miles northwest of the site.

The construction of ANO-1 began after receipt of a construction permit on December 6, 1968, and extended until initial criticality on August 6, 1974. The impacts to the environment from the construction, operation, and decommissioning were evaluated prior to receipt of a construction permit, further investigated during the construction phase, and study results summarized in the Final Environmental Statement for ANO-1 issued in February 1973 [Reference 1].

2.1 General Site Environment

The ANO site is centrally situated on a peninsula about two miles wide and two miles long, which extends into Lake Dardanelle. On three sides, the site is surrounded by lake water. Generally, the site peninsula is at an elevation of about 400 feet, but some areas are above 500 feet. Ground surface within the plant site property line is predominantly meadow. Outside of the property line, forests cover the majority of the peninsula, with pasture, cropland, and residential development each contributing significant proportions of the remaining land-use. A breakdown of the land cover classes, acreage and percentage on the ANO site is shown in Table 2.1-1, with Figure 2.1-2 showing approximate locations on the ANO site.

To the north of the site, the land mass gradually ascends to 1,000 feet altitude at a distance of about 15 miles in the Boston Mountains. The maximum height of the Boston Mountains (2,700 feet) is 41 miles north-northwest of the site. Generally, the Arkansas River follows along the base of the Boston Mountains. The higher portions of the mountains are located west-northwest to east-northeast of the site.

To the south and west of the site, across the Arkansas River and Lake Dardanelle, is a range of hills. Directly south is Mount Nebo, elevation 1,880 feet, at a distance of about eight miles. Further to the west and about 25 miles from the site is Magazine Mountain at 3,042 feet altitude, the highest point in the state. To the east, and extending to the south, the land area is moderately level, interspersed with rolling hills frequently covered with woods.

The site is characterized by excellent natural drainage. Surface runoff from the site is collected in storm water drains, the intake canal, and the emergency cooling pond where it is discharged to its natural destination, Lake Dardanelle. The average annual rainfall at the site is approximately 49 inches [Reference 1].

The region (50-mile radius) surrounding ANO was classified by the GEIS as having a low population, based on the population near the site, and the proximity and size of nearby cities [GEIS, Appendix C, Table C.2]. Nearby towns include the cities of Russellville [Figure 2.1-1] and London. Areas along Lake Dardanelle are developed with permanent residences, along with campgrounds, hiking trails, boat launch areas, and marinas. There are no permanent residences within the 0.65-mile (1.0 km) radius (exclusion zone) of ANO.

Table 2.1-1, ANO Land Cover Classification Areas

Land Cover Classes	Land Cover Class Acreage	Land Cover Class Percentage
Mixed Hardwoods	575	49.4%
Mixed Hardwoods/Pine	39	3.4%
Pine	11	0.9%
Wetland	5	0.4%
Shrub/Sapling	55	4.7%
Disturbed or w/o Cover	449	38.6%
Open water	30	2.6%
Total Land Area	1,164	100.0%

Note: On Figure 2.1-2, mixed hardwoods, pine, and shrub/saplings are grouped as "Mixed Pine-Hardwood", disturbed or without cover is shown as "Early Successional", and wetland and open water are grouped as "water".

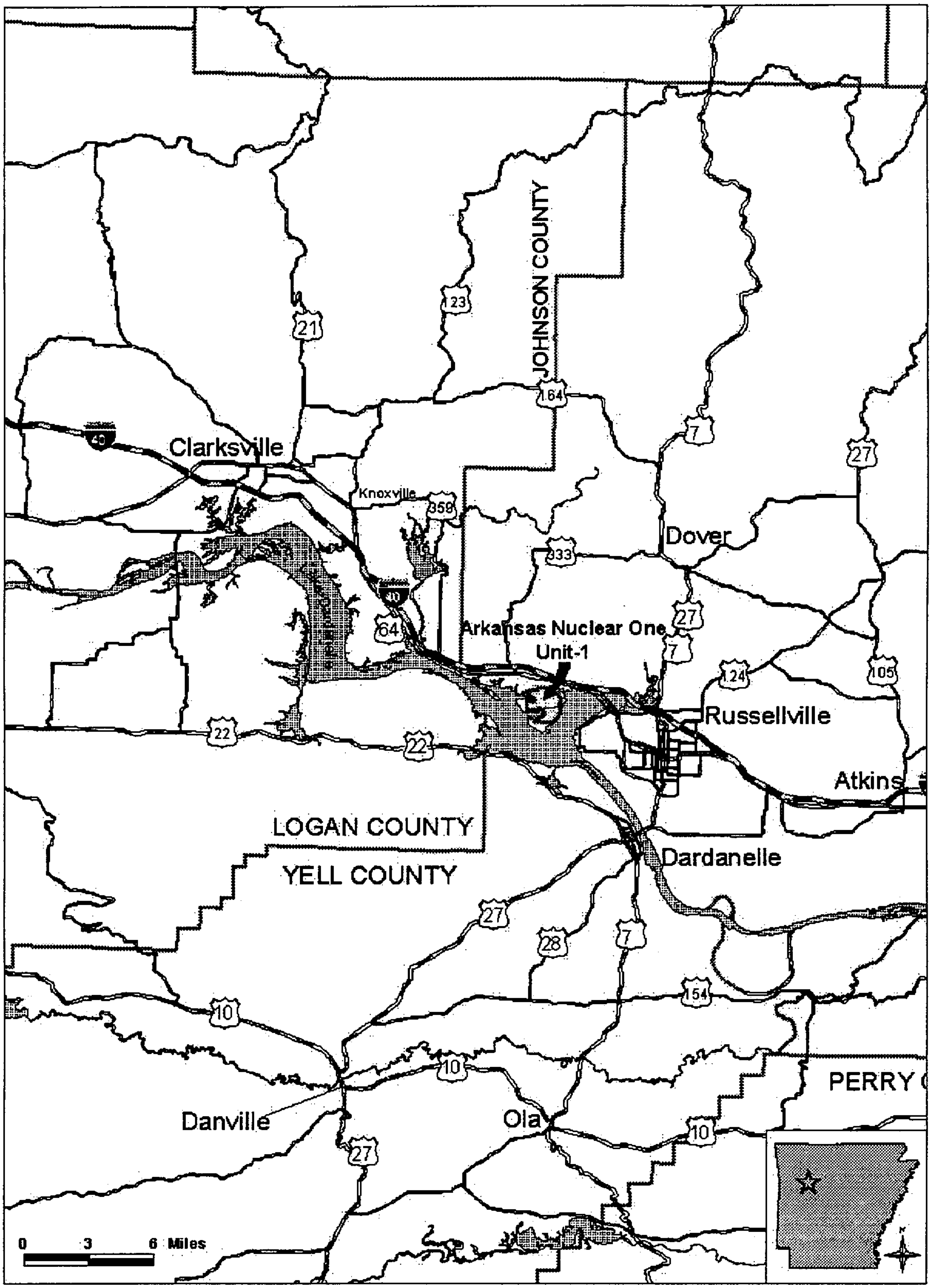

Figure 2.1-1, General Area for Arkansas Nuclear One

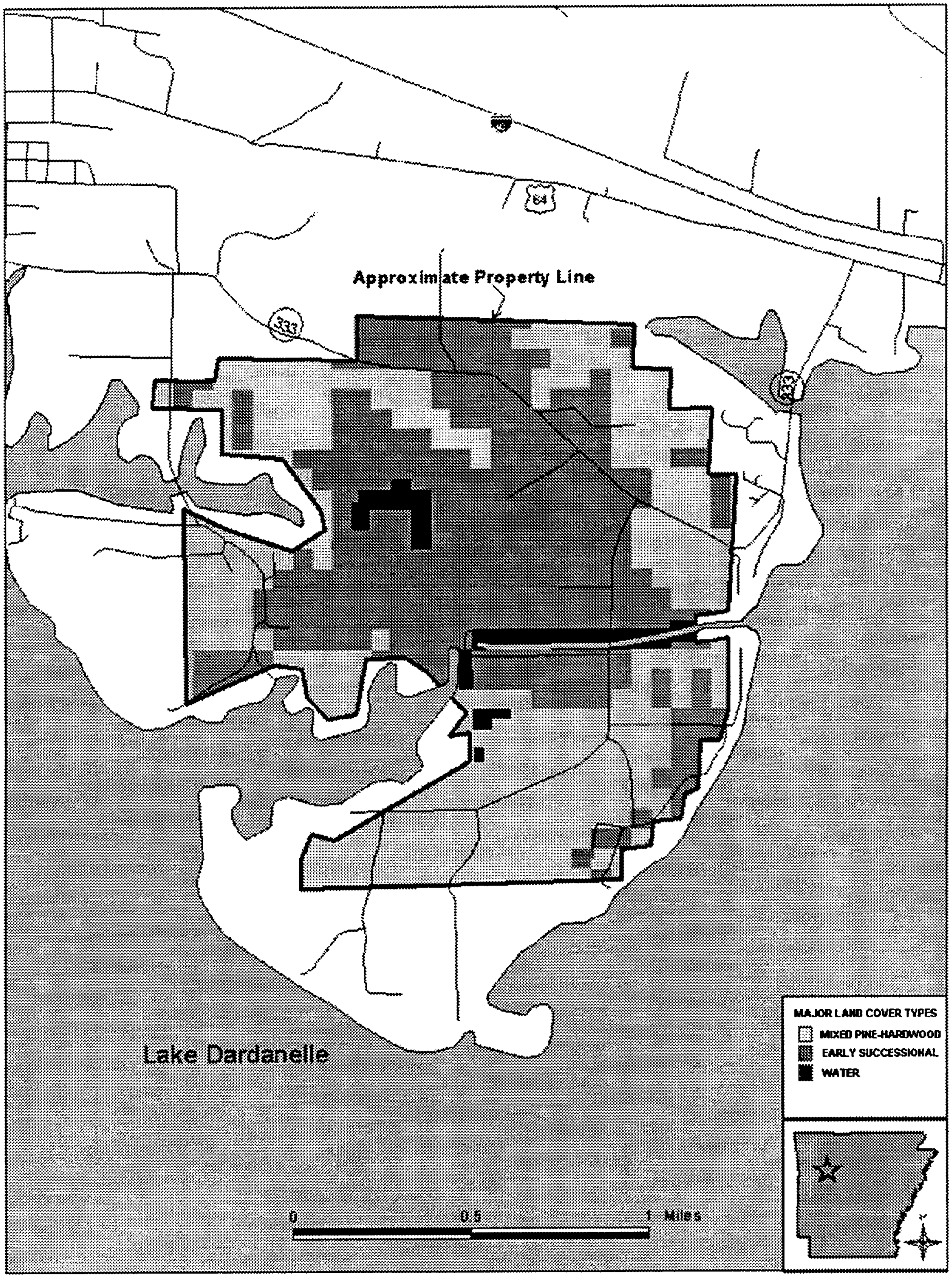

Figure 2.1-2, ANO Land Cover Areas

2.2 Lake Dardanelle

Lake Dardanelle [Figure 2.2-1], which is a part of the Arkansas River, is 50 miles long. It is over 60 feet deep at its lower end and has a surface area of approximately 37,000 acres, with an average depth of approximately 10 feet. The average flow into the lake is 35,620 cfs from a drainage area of 153,703 square miles. Lake Dardanelle has a storage capacity of 486,000 acre-feet, with a normal pool elevation of 338 feet, controlled downstream by the Dardanelle Lock and Dam.

Besides serving the needs of ANO-1, Lake Dardanelle serves a variety of other uses. The lake has been designated as suitable for the propagation of fish/wildlife, primary and secondary contact recreation, and public and industrial water supplies. The water quality of Lake Dardanelle is monitored routinely by the ADEQ. Recent studies have shown no evidence of degraded water quality and that all designated uses for the lake are being fully supported [References 3, 4, and 5].

Water-based recreation activities are a focal point of interest, with abundant opportunities for boating and fishing. In addition, camping, picnicking, sightseeing, photography, and nature study areas are available to visitors at strategic locations around the shoreline. The commercial fishing industry has grown in this area as compared to previous years. The species composition and general health of the fish in Lake Dardanelle are normal for the region.

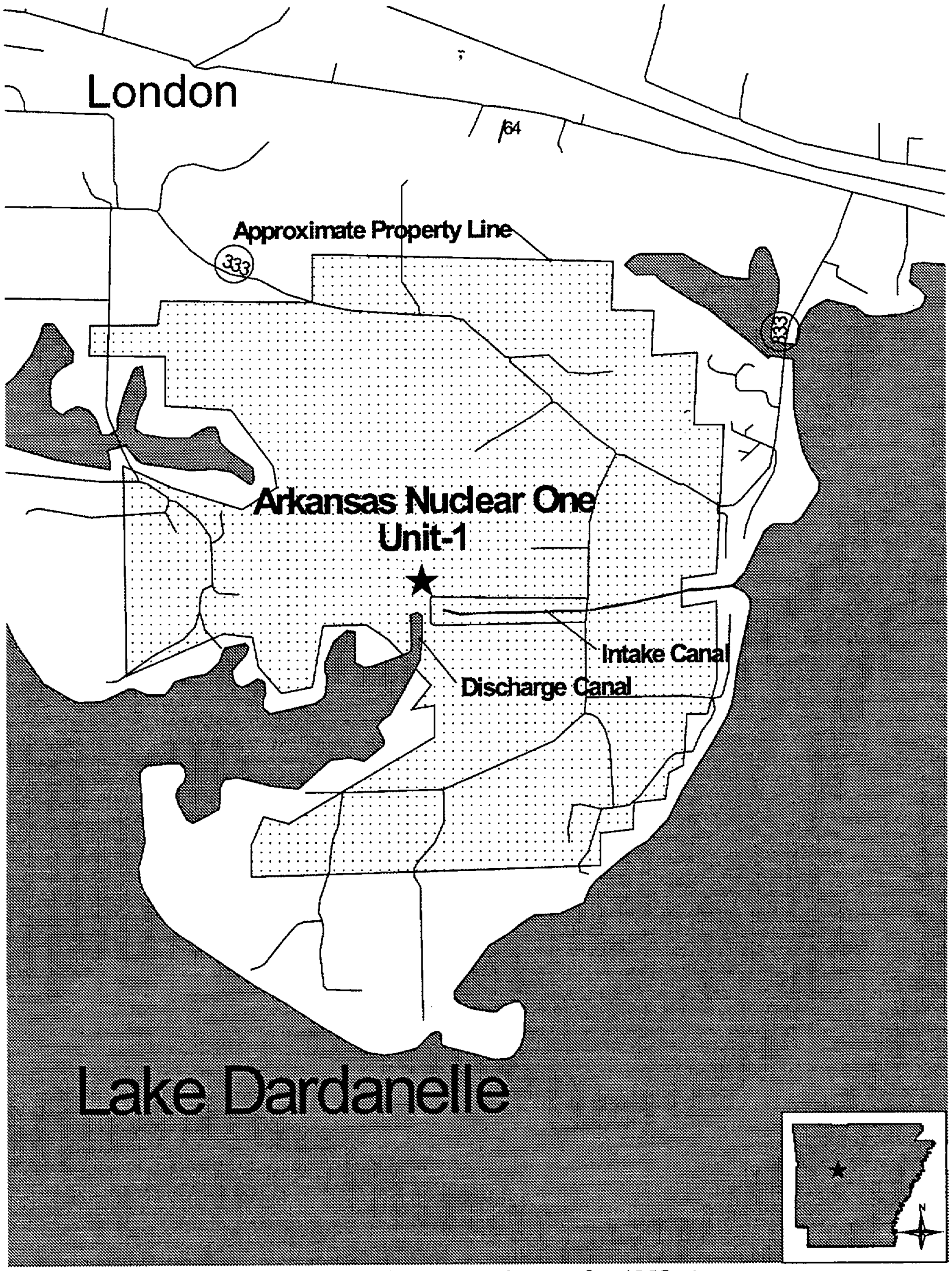

Figure 2.2-1, Lake Dardanelle - Cooling Water Source for ANO–1

2.3 ANO Plant Description

The ANO site has two pressurized water reactors, with nuclear steam supply systems manufactured by Babcock and Wilcox (ANO-1) and Combustion Engineering (ANO-2). ANO-1 was licensed by the NRC and began commercial operation in 1974. ANO-1 has a thermal rating of 2568 MW(t) and a maximum dependable electrical generation capacity of 836 net MW(e) [See Table 2.3-1].

ANO-1 consists of a reactor building, an auxiliary building, and a common turbine building shared with ANO-2. The reactor and nuclear steam supply system for ANO-1 are contained within the reactor building. Mechanical and electrical systems required for the safe operation of ANO-1 are primarily located in the auxiliary and reactor buildings. Figure 2.3-1 shows the general features of the ANO site. Figure 2.3-2 shows the 0.65-mile radius exclusion zone. No residences are permitted within this exclusion zone.

The ANO-1 condensers utilize once-through cooling; whereas, the ANO-2 condensers utilize closed-cycle cooling. Lake Dardanelle serves as the cooling water source for ANO-1 [Figure 2.2-1]. ANO-1 utilizes approximately 1,700 cfs of cooling water to condense steam during normal operation. The cooling water from the Illinois Bayou arm of Lake Dardanelle flows through a 4400-foot long canal to the intake structure. After flowing through the main condenser, the cooling water is then discharged to a 520-foot long canal prior to entering Lake Dardanelle [Reference 1]. A water flow diagram is provided in Attachment A.

The main features of the intake structure include bar grates, traveling screens, and four circulating water pumps. The bar grates have three-inch openings and prevent large debris from entering the intake structure. Inside the bar grates, cooling water passes through 3/8-inch mesh, vertical, traveling screens. The maximum water velocity through the traveling screens is approximately 2.2 fps. Debris that accumulates on the screens is removed through periodic cleaning. After passing through the traveling screens, the cooling water enters the circulating water pumps which have a rated capacity of approximately 191,000 gpm each.

The emergency cooling pond serves as a source of cooling water in the unlikely event of loss of Lake Dardanelle water inventory. The pond has a surface area of 14 acres and a normal depth of 6 feet for a total water inventory of 84 acre-feet.

Entergy Operations operates an independent spent fuel storage installation in accordance with 10CFR Part 72 at ANO. The ISFSI is not within the scope of 10CFR Part 54 since it governs the issuance of renewed operating licenses for nuclear power plants and 10CFR Part 72 governs the ISFSI licenses. Radiological monitoring associated with the ISFSI is included in the site effluent release program.

Table 2.3-1, ANO-1 Site Information

Location:	Pope County, Arkansas 10 km (6 miles) WNW of Russellville latitude 35°-18'-36" N; longitude 93°–13'-53" W Licensee: Entergy Arkansas, Inc.

<u>Unit Information</u>	Unit 1
Docket Number	50-313
Construction Permit	1968
Operating License	1974
Commercial Operation	1974
License Expiration	2014
Licensed Thermal Power [MW(t)]	2568
Design Electrical Rating [net MW(e)]	850
Capability [MW(e)]	836
Type of Reactor	PWR
Nuclear Steam Supply System Vendor	B&W

<u>Cooling Water System</u>

Type: once-through
Source: Lake Dardanelle
Typical Source Temperature Range: 4-28°C (40-83°F)
Design Condenser Temperature Rise: 8.3°C (15°F)
Intake Structure: 1341 m (4400 ft) canal
Discharge Structure: 160 m (520 ft) canal

<u>Site Information</u>

Total Area: 471 ha (1164 acres)
Exclusion Distance: 1.05 km (0.65 mile) radius
Low Population Zone: 6.44 km (4.00 mile) radius
Nearest Major City: Little Rock; 1990 population: 175,795
Site Topography: flat
Surrounding Area Topography: hilly to mountainous
Land Use within 8 km (5 miles): wooded
Nearby Features: The nearest town is London 3 km (2 miles) NW. The size of Lake Dardanelle is 15,000 ha (37,000 acres) and is part of the Arkansas River. The Missouri Pacific Railroad and U. S. Highway I-40 are just N of the site.
Population within an 80-km (50-mile) radius:

1990	2000	2010	2020	2030
200,000	274,037	295,803	312,158	322,991

Sources are:
Reference 1 ANO-1 FES, Reference 2 GEIS, and
U.S. Census Bureau 1990

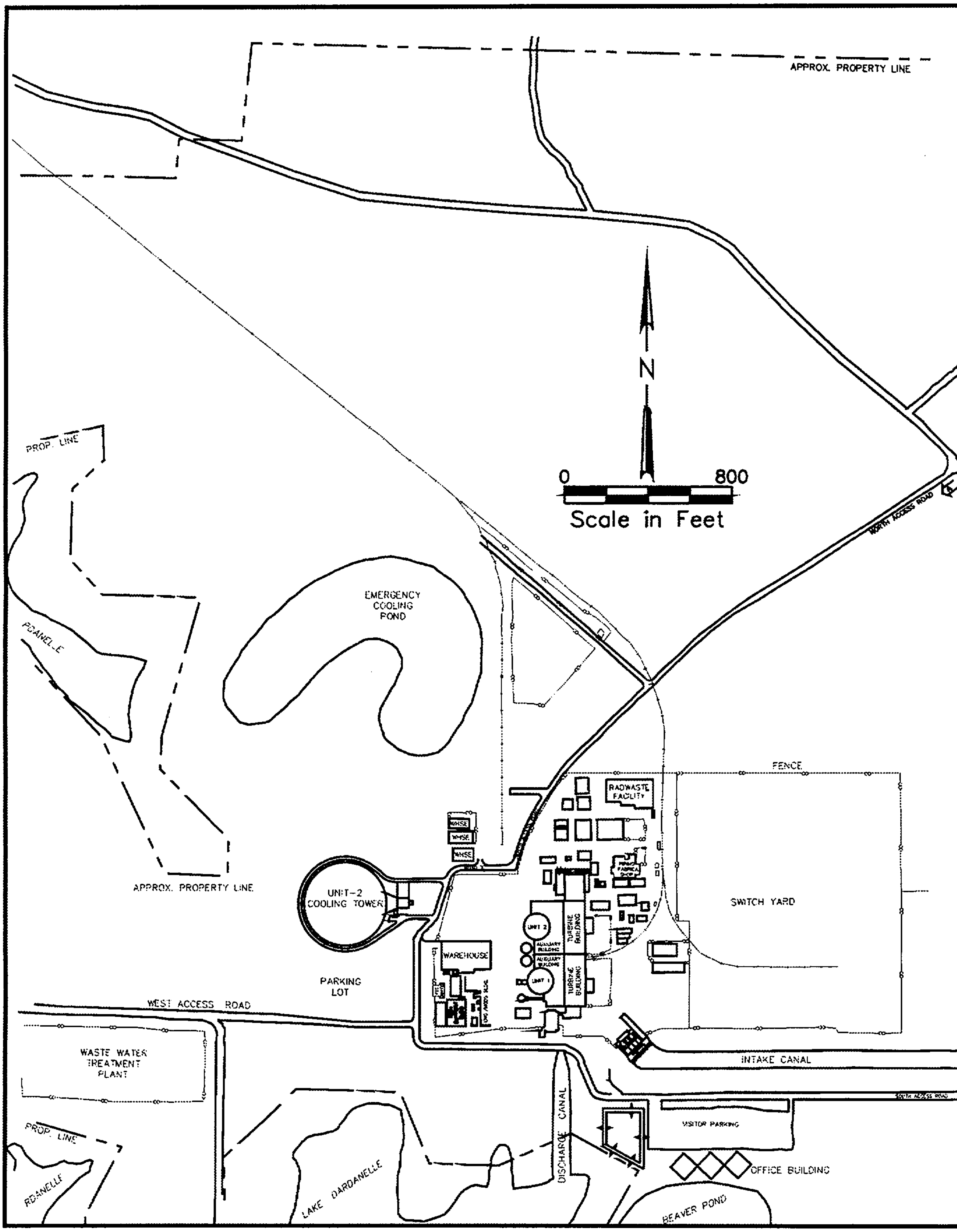

Figure 2.3-1, Arkansas Nuclear One Site – General Features

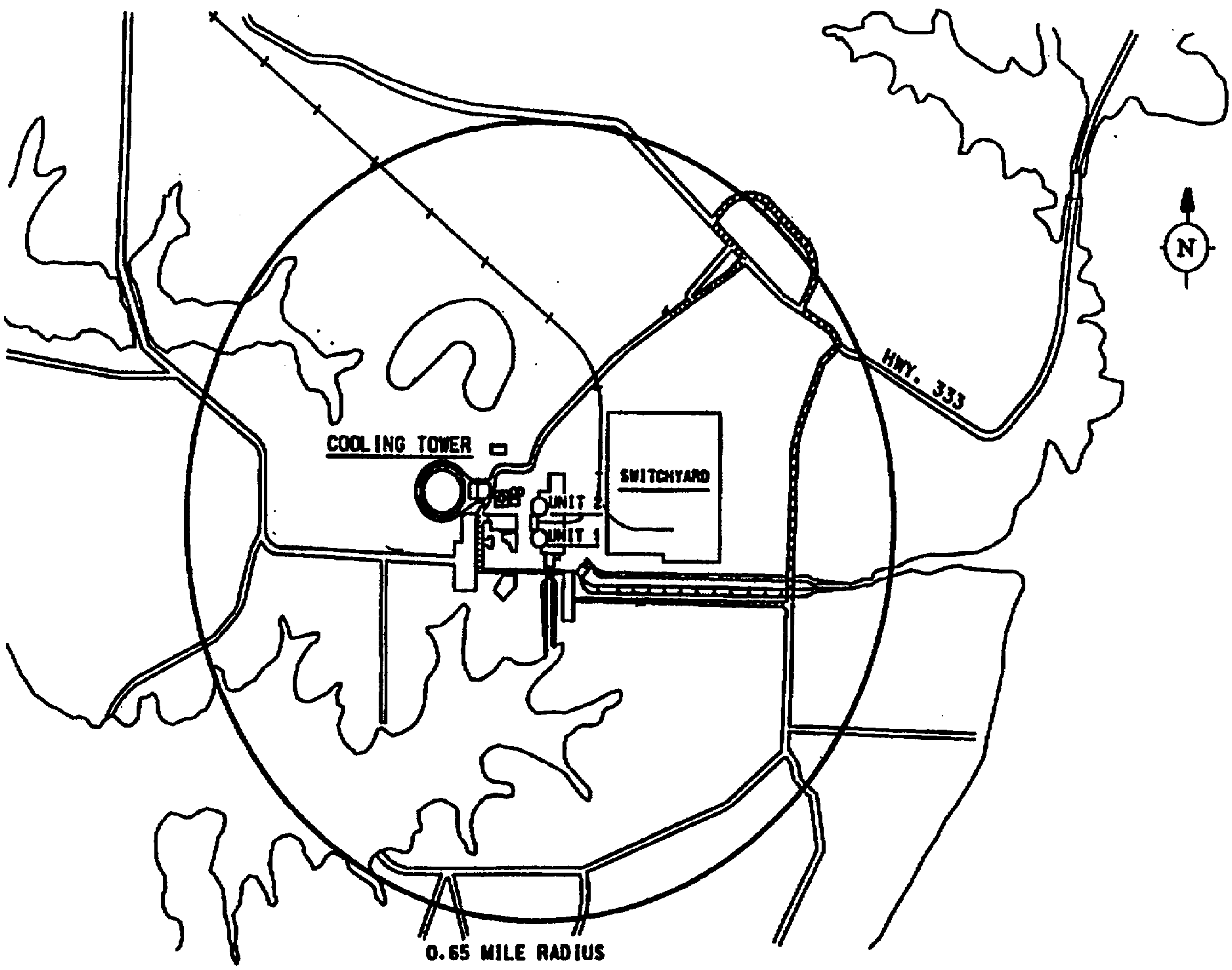

Figure 2.3-2, Arkansas Nuclear One –Exclusion Zone

2.4 Resident Population Estimates

Resident population estimates within 50 miles (80 km) of ANO for the years 2000, 2005, 2010, 2015, 2020, 2025 and 2030 are shown in Tables 2.4-1 through 2.4-7. The computer program SECPOP90 was used to process block-level 1990 census data to prepare population estimates for the region surrounding ANO. [Reference 6]. The 50-mile (80 km) radius area around the plant was divided into sixteen directions that are equivalent to a standard navigational compass rosette. This rosette was further divided into fifteen "inner" radial rings, each with sixteen azimuthal sections. The rings chosen were based on requirements for use in the SAMA analyses. These were grouped for this report into 10-mile (16 km) bands.

The SECPOP90 census data file used for the ANO evaluation contains a record for the location (geometric centroid coordinates) and the population of each census block (6,660,337 records) in the continental U.S. It is a binary file sorted primarily by descending longitude (west to east) and secondarily by descending latitude (north to south). The westernmost point in the census data file that lies on or to the east of the western longitude boundary of the geometric rosette was first found. For that data point and each subsequent data point read from the file, it was determined if the point lies between the north and south latitudinal boundaries for the 50-mile radii area. When a point was found to lie between the established boundaries, the distance of that point from the site is calculated to determine if in fact the point lies within the outer limits of the rosette grid. If the point met the distance criteria, it was then processed to determine the exact grid element in which it lies based on its radial distance and direction from the site. The population associated with that data point is then added to the population of that grid section. This process produced the 1990 population estimate for each rosette section.

The countywide 1998 population estimates, which were the most complete and current estimates available, were then utilized to update the 1990 estimates to 1998. For each rosette section, the fraction of its area in each county was estimated. These fractions were then used to calculate a county-area weighted population growth factor (1998 county population divided by 1990 county population) for the section. The 1990 section population was then multiplied by this growth factor to produce the 1998 population estimate for that section.

Since countywide projections were unavailable, the statewide 2000-2025 Bureau of the Census data was then used to project the future rosette section populations for the years 2000 to 2030 in five-year steps. For each step, a statewide growth factor was calculated by dividing the state population projection for that year by the 1998 state population estimate. A value for the year 2030 population was found by extrapolation. The mean change in population from 2015 to 2020 and from 2020 to 2025 was used to extrapolate the change for 2025 to 2030. This change was then added to the year 2025 data to prepare the year 2030 population projection. The section population projection for this step year is then calculated by multiplying the 1998 section population by the state growth factor.

Table 2.4-1, Resident Population Estimates, 2000

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,503	1,030	355	352	1,850	5,090
NNE	2,221	3,859	269	380	822	7,551
NE	14,775	4,630	1,929	363	1,320	23,017
ENE	11,507	2,987	2,023	1,849	4,848	23,214
E	4,506	5,772	9,009	5,091	21,611	45,989
ESE	1,899	639	4,794	3,294	38,275	48,901
SE	841	894	1,305	1,825	3,311	8,176
SSE	1,118	701	332	4,640	12,334	19,125
S	473	2,037	172	781	9,257	12,720
SSW	606	1,341	504	484	1,898	4,833
SW	391	3,026	617	615	600	5,249
WSW	315	1,142	881	1,198	1,372	4,908
W	58	237	5,062	8,033	6,521	19,911
WNW	713	1,781	4,455	9,993	4,078	21,020
NW	322	2,295	10,073	1,838	1,330	15,858
NNW	1,321	3,333	2,377	748	696	8,475
Total	42,569	35,704	44,157	41,484	110,123	274,037

Table 2.4-2, Resident Population Estimates, 2005

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,571	1,077	371	368	1,934	5,321
NNE	2,322	4,033	281	397	859	7,892
NE	15,443	4,839	2,016	379	1,379	24,056
ENE	12,027	3,122	2,114	1,932	5,068	24,263
E	4,710	6,033	9,416	5,321	22,589	48,069
ESE	1,985	667	5,011	3,443	40,007	51,113
SE	879	934	1,364	1,908	3,460	8,545
SSE	1,169	733	347	4,850	12,892	19,991
S	494	2,129	179	816	9,676	13,294
SSW	633	1,401	527	506	1,984	5,051
SW	409	3,163	645	643	627	5,487
WSW	329	1,194	921	1,252	1,434	5,130
W	60	248	5,291	8,396	6,816	20,811
WNW	745	1,861	4,656	10,445	4,263	21,970
NW	336	2,399	10,528	1,922	1,390	16,575
NNW	1,381	3,484	2,484	782	727	8,858
Total	44,493	37,317	46,151	43,360	115,105	286,420

Table 2.4-3, Resident Population Estimates, 2010

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,622	1,112	383	380	1,997	5,494
NNE	2,398	4,165	291	410	887	8,151
NE	15,948	4,998	2,082	392	1,425	24,845
ENE	12,421	3,224	2,184	1,995	5,234	25,058
E	4,864	6,231	9,724	5,495	23,328	49,642
ESE	2,050	689	5,175	3,556	41,316	52,786
SE	907	965	1,409	1,970	3,574	8,825
SSE	1,207	757	358	5,009	13,314	20,645
S	510	2,198	185	843	9,993	13,729
SSW	654	1,447	544	523	2,049	5,217
SW	422	3,266	666	664	648	5,666
WSW	340	1,233	951	1,293	1,481	5,298
W	62	256	5,465	8,671	7,040	21,494
WNW	769	1,922	4,809	10,787	4,402	22,689
NW	347	2,477	10,873	1,984	1,435	17,116
NNW	1,426	3,598	2,565	808	751	9,148
Total	45,947	38,538	47,664	44,780	118,874	295,803

Table 2.4-4, Resident Population Estimates, 2015

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,669	1,144	394	391	2,055	5,653
NNE	2,467	4,285	299	422	913	8,386
NE	16,409	5,142	2,142	403	1,466	25,562
ENE	12,779	3,318	2,247	2,053	5,385	25,782
E	5,005	6,410	10,005	5,654	24,002	51,076
ESE	2,109	709	5,325	3,659	42,509	54,311
SE	934	993	1,450	2,027	3,677	9,081
SSE	1,242	779	368	5,153	13,698	21,240
S	525	2,262	191	868	10,281	14,127
SSW	673	1,489	560	538	2,108	5,368
SW	434	3,361	685	683	666	5,829
WSW	350	1,269	978	1,330	1,524	5,451
W	64	263	5,622	8,921	7,243	22,113
WNW	791	1,978	4,948	11,099	4,529	23,345
NW	357	2,549	11,187	2,042	1,477	17,612
NNW	1,467	3,702	2,639	831	772	9,411
Total	47,275	39,653	49,040	46,074	122,305	304,347

Table 2.4-5, Resident Population Estimates, 2020

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,712	1,174	404	401	2,108	5,799
NNE	2,530	4,395	307	433	936	8,601
NE	16,830	5,274	2,197	413	1,503	26,217
ENE	13,107	3,403	2,304	2,106	5,523	26,443
E	5,133	6,575	10,262	5,799	24,618	52,387
ESE	2,164	727	5,461	3,752	43,600	55,704
SE	958	1,018	1,487	2,079	3,771	9,313
SSE	1,274	799	378	5,285	14,050	21,786
S	539	2,320	196	890	10,545	14,490
SSW	690	1,527	574	551	2,162	5,504
SW	445	3,447	703	700	684	5,979
WSW	359	1,301	1,003	1,365	1,563	5,591
W	66	270	5,767	9,150	7,429	22,682
WNW	812	2,029	5,075	11,384	4,645	23,945
NW	366	2,614	11,474	2,094	1,515	18,063
NNW	1,505	3,797	2,707	853	792	9,654
Total	48,490	40,670	50,299	47,255	125,444	312,158

Table 2.4-6, Resident Population Estimates, 2025

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,745	1,196	412	408	2,149	5,910
NNE	2,579	4,480	313	441	954	8,767
NE	17,156	5,376	2,240	421	1,532	26,725
ENE	13,361	3,469	2,349	2,146	5,630	26,955
E	5,232	6,702	10,460	5,911	25,094	53,399
ESE	2,205	742	5,567	3,825	44,444	56,783
SE	976	1,038	1,516	2,120	3,844	9,494
SSE	1,299	814	385	5,388	14,322	22,208
S	549	2,365	199	907	10,749	14,769
SSW	703	1,557	585	562	2,204	5,611
SW	454	3,514	716	714	697	6,095
WSW	366	1,326	1,023	1,391	1,593	5,699
W	67	275	5,878	9,327	7,572	23,119
WNW	827	2,068	5,173	11,604	4,735	24,407
NW	373	2,665	11,696	2,135	1,544	18,413
NNW	1,534	3,871	2,760	869	808	9,842
Total	49,426	41,458	51,272	48,169	127,871	318,196

Table 2.4-7, Resident Population Estimates, 2030

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,771	1,215	418	415	2,181	6,000
NNE	2,618	4,548	317	448	969	8,900
NE	17,414	5,457	2,273	428	1,555	27,127
ENE	13,562	3,521	2,384	2,179	5,715	27,361
E	5,311	6,803	10,618	6,000	25,472	54,204
ESE	2,239	753	5,651	3,883	45,113	57,639
SE	991	1,053	1,539	2,151	3,902	9,636
SSE	1,318	827	391	5,469	14,538	22,543
S	557	2,400	202	921	10,911	14,991
SSW	714	1,580	594	571	2,237	5,696
SW	461	3,567	727	725	707	6,187
WSW	371	1,346	1,038	1,412	1,617	5,784
W	68	279	5,967	9,468	7,686	23,468
WNW	840	2,099	5,251	11,779	4,807	24,776
NW	379	2,705	11,872	2,167	1,567	18,690
NNW	1,557	3,929	2,801	882	820	9,989
Total	50,171	42,082	52,043	48,898	129,797	322,991

3.0 PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is renewal of the existing ANO-1 operating license for an additional 20 years beyond the expiration of the current operating license. The facility operating license for ANO-1 currently expires on midnight May 20, 2014 and would be renewed to expire at midnight on May 20, 2034.

There are no changes related to license renewal with respect to the operations of ANO-1 that would directly affect the environment or plant effluents that affect the environment during the period of license extension. The environmental impacts from continued operation of ANO-1 are similar to those experienced during the original operating term and evaluated in the Final Environmental Statement [Reference 1].

3.2 Plant Modifications or Refurbishments which are Required for License Renewal

10CFR51.53(c)(2) requires that a license renewal applicant's ER contain: "a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures as described in accordance with Section 54.21 of this chapter. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment."

The objective of the review required by 10CFR54.21 is to determine whether the detrimental effects of plant aging could preclude certain ANO-1 systems, structures, and components from performing, in accordance with the manner in which they were initially designed, during the additional 20 years of operation requested in the license renewal application. The evaluation of structures and components as required by 10CFR54.21 has been completed.[1] This evaluation did not identify the need for refurbishment of structures or components. In addition, no other modifications or refurbishment activities related to license renewal have been identified as necessary.

[1] A full description of this review is contained in ANO-1 License Renewal Application [Reference 7].

3.3 Programs for Managing Aging

The programs for managing aging of systems and equipment at ANO-1 are described in the ANO-1 License Renewal Application [Reference 7]. The evaluation of structures and components required by 10CFR54.21 identified some new inspection activities necessary to continue operation of ANO-1 during the additional 20 years beyond the initial license term. These activities are described in the ANO-1 License Renewal Application [Reference 7]. The additional inspection activities are consistent with normal plant component inspections, and therefore, are not expected to cause any significant environmental impact. The majority of the aging management programs are either existing programs or modest modifications of existing programs.

3.4 Employment

The non-outage work force at ANO consists of approximately 1313 persons. There are 1145 Entergy employees normally on-site. The remaining 168 persons are baseline contractor employees. Table 3.4-1 shows employee residences by county and city. The GEIS estimated that an additional 60 employees would be necessary for operation during the period of extended operation. Since there will not be significant new aging management programs added at ANO, Entergy Operations believes that it will be able to manage the necessary programs with existing staff. Therefore, Entergy Operations has no plans to add non-outage employees to support plant operations during the period of the extended license.

Refueling and maintenance outages typically have durations of approximately 30 days. Depending on the scope of these outages, an additional 1,300 to 1,400 workers are typically on-site. The number of workers required on-site for normal plant outages during the period of the renewed license is expected to be consistent with the numbers of additional workers used for past outages at ANO.

Table 3.4-1 Arkansas Employee Residence Information (ANO), August 1999

County and City	Entergy Employees
CONWAY COUNTY	11
Hattieville	1
Morrilton	7
Springfield	3
CRAWFORD COUNTY	1
Alma	1
FAULKNER COUNTY	19
Conway	19
FRANKLIN COUNTY	2
Alix	1
Ozark	1
GARLAND COUNTY	1
Hot Springs	1
JOHNSON COUNTY	82
Clarksville	31
Coal Hill	4
Hagerville	1
Hartman	4
Knoxville	15
Lamar	27
LOGAN COUNTY	8
New Blaine	1
Scranton	5
Subiaco	2
LONOKE COUNTY	1
Austin	1
PERRY COUNTY	1
Bigelow	1
POPE COUNTY	938
Atkins	33
Dover	89
Hector	8
London	62
Pelsor	1
Pottsville	30
Russellville	715

Table 3.4-1, Arkansas Employee Residence Information (ANO), August 1999 (continued)

County and City	Entergy Employees
PULASKI COUNTY	6
Little Rock	3
Maumelle	1
North Little Rock	1
Sherwood	1
YELL COUNTY	75
Belleville	4
Casa	3
Centerville	1
Danville	4
Dardanelle	55
Delaware	2
Havana	1
Ola	3
Plainview	1
Waveland	1
Total	1145

Table 3.4-1 Arkansas Employee Residence Information (ANO), August 1999 (continued)

County and City	Baseline Contractor Employees
CONWAY COUNTY	5
Jerusalem	1
Morrilton	4
FRANKLIN COUNTY	1
Ozark	1
JOHNSON COUNTY	25
Clarksville	10
Hartman	5
Knoxville	3
Lamar	7
PERRY COUNTY	1
Perryville	1
POPE COUNTY	104
Atkins	9
Dover	16
Hector	3
London	7
Pelsor	1
Pottsville	5
Russellville	63
SEARCY COUNTY	2
Witt Springs	1
Marshall	1
YELL COUNTY	30
Belleville	1
Buckville	1
Danville	4
Dardanelle	16
Havana	4
Ola	2
Plainview	2
Total	168

4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

4.1 Discussion of GEIS Categories for Environmental Issues

The Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NUREG-1437, summarizes the approach and findings of a systematic inquiry into the potential environmental consequences of renewing the licenses and operating individual nuclear power plants for an additional 20 years. The GEIS assesses 92 environmental issues relevant to license renewal. The GEIS assessment of these issues was used to assign the Categories to the 92 environmental issues listed in 10CFR Part 51, Subpart A, Appendix B, Table B-1. In turn, Table B-1 was used to develop the requirements for the environmental issues listed in 10CFR51.53(c)(3)(ii). The GEIS assigned most environmental issues[2] one of the three following significance levels:

Small: Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

Moderate: Environmental effects are sufficient to alter noticeably but not to destabilize important attributes of the resource.

Large: Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

4.1.1 Category 1 Issues

Category 1 issues are defined as those environmental issues whose analysis in the GEIS has shown that:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristics;

- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective off-site radiological impacts from the fuel cycle and from high-level waste and spent fuel); and

[2] Of the 92 environmental issues evaluated in the GEIS and Addendum 1, 69 were designated as Category 1 and 21 were designated as Category 2. Two environmental issues were assigned as Category NA (Not Applicable). These issues are electromagnetic fields (chronic effects) and environmental justice. Footnotes to Table 9.1, in the GEIS provide details on the category definition for these issues.

- mitigation of adverse impacts associated with the issue has been considered in the analysis and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

Sixty-nine of the issues evaluated in the GEIS and Addendum 1 [Reference 35] were found to be Category 1. These issues are identified in Appendix B to Subpart A of Part 51 as not requiring additional plant-specific analysis. 10CFR51.53(c)(3)(i) provides that the environmental report for the operating license renewal stage need not contain analyses of the environmental impacts of the license renewal issues identified as Category 1. Entergy Operations adopts the generic conclusions of the GEIS and Addendum 1.

4.1.2 Category 2 Issues

For the Category 2 issues, the NRC analysis presented in the GEIS has shown that one or more of the Category 1 criteria cannot be met, and therefore, additional plant-specific review is required. Twenty-one of the issues evaluated in the GEIS and Addendum 1 were found to meet the Category 2 criteria. The NRC's findings on the environmental impact of these issues are summarized in 10CFR Part 51, Subpart A, Appendix B, Table B-1. The ER must contain an analysis of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal, and the impacts of operation during the renewal term, for those issues identified as Category 2 (plant-specific) issues in Appendix B to Subpart A of 10CFR Part 51. These 21 issues have been incorporated into 12 specific analytical requirements that are listed in 10CFR51.53(c)(3)(ii).

4.1.3 Table B-1, Appendix B to Subpart A and 10CFR51.53(c)(3)(ii) Issues

Table 4.1-1, of the ER, was developed to show the relationship of the Table B-1 Category 2 issues to the 10CFR51.53(c)(3)(ii) requirements. Table B-1, Subpart A, Appendix B lists 21 Category 2 issues. The Category 2 issues listed in Table B-1 can be referenced to the 12 analytical requirements defined in 10CFR51.53(c)(3)(ii). For example, 10CFR51.53(c)(3)(ii)(I) requires that an assessment of the impact of the proposed action on housing availability, land-use, public schools, and public water supplies be performed. Table B-1 lists five socioeconomic Category 2 issues that can be addressed in the same analysis required by 10CFR51.53(c)(3)(ii)(I). Table 4.1-1 lists the issue, the findings from Table B-1, and the applicable 10CFR51.53(c)(3)(ii) requirements. The issues were grouped by broader topics, such as surface water quality, aquatic ecology, etc.

4.1.4 Review of 10CFR51.53(c)(3)(ii) Issues

The review and analysis for the 10CFR51.53(c)(3)(ii) issues are found in Sections 4.2 through 4.13. The issues can be placed into one of three categories, which are discussed below. Table 4.1-2 provides a summary of the results for the issues listed in 10CFR51.53(c)(3)(ii).

4.1.4.1 10CFR51.53(c)(3)(ii) Issues not Applicable to ANO-1

No analysis is provided for issues that are not applicable to ANO-1. The basis for Entergy Operations' determination that a certain issue is not applicable is set forth in the specific section of the ER. Three of the issues listed in 10CFR51.53(c)(3)(ii) are not applicable to the ANO site and one other is not applicable to ANO-1 specifically as shown in Table 4.1-2. A discussion of the four non-applicable issues (water use conflicts, ground-water use conflicts, ground-water quality, and vehicle exhaust emissions) is provided in subsequent sections of the ER.

4.1.4.2 10CFR51.53(c)(3)(ii) Issues Applicable to ANO-1

The format for the Section 4.0 discussion of the 10CFR51.53(c)(3)(ii) issues applicable to ANO-1 is described below:

- Requirement - The requirement from 10CFR51.53(c)(3)(ii) is restated.

- Findings from Table B-1, Appendix B to Subpart A - The Finding(s) for the issue from Table B-1 - Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Subpart A, is presented. Several of the issues in 10CFR51.53(c)(3)(ii) have more than one issue from Table B-1 associated with that issue.

- Background - An excerpt from the applicable section of the GEIS is provided as background. The specific section of the GEIS is referenced for the convenience of the reader.

- Analysis of Environmental Impact - An analysis of the environmental impact as required by 10CFR51.53(c)(3)(ii) is provided, taking into account information provided in the GEIS, Appendix B to Subpart A of Part 51, as well as ANO-1 specific information.

- Consideration of Alternatives for Reducing Adverse Impacts - The alternatives to reduce or avoid adverse environmental effects are assessed as required by 10CFR51.45(c) and 10CFR51.53(c)(3)(iii).

4.1.4.3 10CFR51.53(c)(3)(ii) Issues Applicable to ANO-1 Related to Refurbishment

As discussed in Section 3.2, Plant Modifications or Refurbishments Required for License Renewal, the evaluation of structures and components required by 10CFR54.21 did not identify any major plant refurbishment activities[4] or modifications necessary to support the continued operation of ANO-1 beyond the end of the existing operating license. Accordingly, there are no identified refurbishment activities or modifications that would affect the environment or plant effluents. Therefore, further analysis of these issues is not required.

[4] GEIS, Appendix B, Table B.2 lists major refurbishment/replacement activities associated with license renewal.

Table 4.1-1, Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SURFACE WATER QUALITY, HYDROLOGY, AND USE (for all plants)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	SMALL OR MODERATE. The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations. See 10CFR51.53(c)(3)(ii)(A).	[10CFR51.53(c)(3)(ii)(A)] If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Entrainment of fish and shellfish in early life stages	SMALL, MODERATE, OR LARGE. The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems) (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Impingement of fish and shellfish	SMALL, MODERATE, OR LARGE. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems) (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Heat shock	SMALL, MODERATE, OR LARGE. Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40CFR Part 125, or equivalent state permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

GROUNDWATER USE AND QUALITY

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Ground-water use conflicts (potable and service water, and dewatering; plants that use >100 gpm)	SMALL, MODERATE, OR LARGE. Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users. See 10CFR51.53(c)(3)(ii)(C).	[10CFR51.53(c)(3)(ii)(C)] If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total on-site) of ground-water per minute, an assessment of the impact of the proposed action on ground-water use must be provided.
Ground-water use conflicts (plants using cooling towers withdrawing make-up water from a small river)	SMALL, MODERATE, OR LARGE. Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other ground-water or upstream surface water users come on line before the time of license renewal. See 10CFR51.53(c)(3)(ii)(A).	[10CFR51.53(c)(3)(ii)(A)] If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

GROUNDWATER USE AND QUALITY (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Ground-water use conflicts (Ranney wells)	SMALL, MODERATE, OR LARGE. Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal. See 10CFR51.53(c)(3)(ii)(C).	[10CFR51.53(c)(3)(ii)(C)] If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total on-site) of ground-water per minute, an assessment of the impact of the proposed action on ground-water use must be provided.
Ground-water quality degradation (cooling ponds at inland sites)	SMALL, MODERATE, OR LARGE. Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses. See 10CFR51.53(c)(3)(ii)(D).	[10CFR51.53(c)(3)(ii)(D)] If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on ground-water quality must be provided.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

TERRESTRIAL RESOURCES

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Refurbishment impacts	SMALL, MODERATE, OR LARGE. Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application. See 10CFR51.53(c)(3)(ii)(E).	[10CFR51.53(c)(3)(ii)(E)] All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

THREATENED OR ENDANGERED SPECIES (for all plants)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Threatened or endangered species	SMALL, MODERATE, OR LARGE. Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected. See 10CFR51.53(c)(3)(ii)(E).	[10CFR51.53(c)(3)(ii)(E)] All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AIR QUALITY

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Air quality during refurbishment (nonattainment and maintenance areas)	SMALL, MODERATE, OR LARGE. Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage. See 10CFR51.53(c)(3)(ii)(F).	[10CFR51.53(c)(3)(ii)(F)] If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

HUMAN HEALTH

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	SMALL, MODERATE, OR LARGE. These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically. See 10CFR51.53(c)(3)(ii)(G).	[10CFR51.53(c)(3)(ii)(G)] If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided.
Electromagnetic fields, acute effects (electric shock)	SMALL, MODERATE, OR LARGE. Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site. See 10CFR51.53(c)(3)(ii)(H).	[10CFR51.53(c)(3)(ii)(H)] If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant[3] to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided.

[3] The plant is defined as the nuclear reactors, steam-electric systems, intakes, discharges, and all other on-station facilities involved in the production of electricity. Transmission lines and other off-station facilities are not part of the plant. (NUREG-1555, SRP-ER, Introduction Chapter, Definitions, February 1999)

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Housing impacts	SMALL, MODERATE, OR LARGE. Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or in areas with growth control measures that limit housing development. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Public services: public utilities	SMALL OR MODERATE. An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Public services, education (refurbishment)	SMALL, MODERATE, OR LARGE. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Offsite land use (refurbishment)	SMALL OR MODERATE. Impacts may be of moderate significance at plants in low population areas. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Offsite land-use (license renewal term)	SMALL, MODERATE, OR LARGE. Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Public services, Transportation	SMALL, MODERATE, OR LARGE. Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. See 10CFR51.53(c)(3)(ii)(J).	[10CFR51.53(c)(3)(ii)(J)] All applicants shall assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Historic and archaeological resources	SMALL, MODERATE, OR LARGE. Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection. See 10CFR51.53(c)(3)(ii)(K).	[10CFR51.53(c)(3)(ii)(K)] All applicants shall assess whether any historic or archaeological properties will be affected by the proposed project.

POSTULATED ACCIDENTS

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Severe accidents	SMALL. The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives. See 10CFR51.53(c)(3)(ii)(L).	[10CFR51.53(c)(3)(ii)(L)] If the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment, a consideration of alternatives to mitigate severe accidents must be provided.

Table 4.1-2, Summary of Results for Analyses of Category 2 Issues

Category 2 Issue **10CFR51.53(c)(3)(ii)Requirement**	**Summary of Analysis Results**
Water use conflicts (Plants with cooling towers and cooling ponds) 10CFR51.53(c)(3)(ii)(A)	Not applicable to ANO–1 (ANO-1 utilizes once-through cooling).
Entrainment, impingement, and heat shock of fish and shellfish 10CFR51.53(c)(3)(ii)(B)	Impact is small. State and federal agencies concluded that ANO has had no significant adverse impacts on Lake Dardanelle.
Ground-water use conflicts (Ranney Wells or pumps more than 100 gallons per minute of groundwater) 10CFR51.53(c)(3)(ii)(C)	Not applicable to ANO (There are no wells located on the ANO site).
Ground-water quality (Plants with cooling ponds) 10CFR51.53(c)(3)(ii)(D)	Not applicable to ANO (ANO-1 utilizes once-through cooling).
Refurbishment impacts on important plant and animal habitats, and threatened or endangered species 10CFR51.53(c)(3)(ii)(E)	Impact is small. No major refurbishment activities identified. Six federal species listed due to potential geographic range. No state species listed.
Vehicle Exhaust Emissions 10CFR51.53(c)(3)(ii)(F)	Not applicable to ANO (ANO is not located in or near non-attainment or maintenance area).
Microbiological (thermophilic) organisms 10CFR51.53(c)(3)(ii)(G)	Impact is small. No concerns identified by ANO or state agency.
Electrical shock from induced currents 10CFR51.53(c)(3)(ii)(H)	Impact is small. Potential for electric shock is not significant.
Housing, land-use, public schools and public water supply impacts 10CFR51.53(c)(3)(ii)(I)	Impact is small. Site-specific reviews showed impacts to be less than those evaluated in the GEIS.
Local transportation impacts 10CFR51.53(c)(3)(ii)(J)	Impact is small. Site-specific reviews showed impacts to be less than those evaluated in the GEIS.
Historic and archaeological properties 10CFR51.53(c)(3)(ii)(K)	Impact is small. No significant properties identified.
Severe accident mitigation alternatives 10CFR51.53(c)(3)(ii)(L)	No impact from continued operation.

4.2 Water Use Conflicts (Plants with Cooling Towers and Cooling Ponds)

4.2.1 Requirement [10CFR51.53(c)(3)(ii)(A)]

If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.

4.2.2 Analysis of Environmental Impact

ANO-1 uses a once-through cooling system;[5] therefore, this issue is not applicable to ANO-1 and analysis is not required.

4.3 Entrainment, impingement, and heat shock of fish and shellfish

4.3.1 Requirement [10CFR51.53(c)(3)(ii)(B)]

If the applicant's plant utilizes once-through cooling[5] or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.3.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid. See 10CFR51.53(c)(3)(ii)(B)." "The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. See 10CFR51.53(c)(3)(ii)(B)." "Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants. See 10CFR51.53(c)(3)(ii)(B)."

[5] In a once-through cooling system, circulating water for condenser cooling is drawn from an adjacent body of water, such as a lake or river, passed through the condenser tubes, and returned at a higher temperature to the adjacent body of water. The waste heat is dissipated to the atmosphere, mainly by evaporation from the water body and, to a much smaller extent, by conduction, convection, and thermal radiation loss [Reference 2].

4.3.3 GEIS Background

The impacts of fish and shellfish entrainment are small at many plants, but they may be moderate or even large at a few plants with once-through cooling systems. Further, ongoing restoration efforts may increase the numbers of fish susceptible to intake effects during the license renewal period, so that entrainment studies conducted in support of the original license may no longer be valid. For these reasons, the entrainment of fish and shellfish is a Category 2 issue for plants with once-through cooling [Reference 2 GEIS Section 4.2.2.1.2].

Aquatic organisms that are drawn into the intake with the cooling water and are too large to pass through the debris screens may be impinged against the screens. Mortality of fish that are impinged is high at many plants because impinged organisms are eventually suffocated by being held against the screen mesh or are abraded, which can result in fatal infection. Impingement can affect large numbers of fish and invertebrates (crabs, shrimp, jellyfish, etc.). As with entrainment, operational monitoring and mitigative measures have allayed concerns about population-level effects at most plants, but impingement mortality continues to be an issue at others.

Consultation with resource agencies reveals that impingement is a frequent concern at once-through power plants, particularly where restoration of anadromous fish may be affected. In several cases, significant modifications were made to the intake structure to substantially reduce mortality due to impingement. Impingement is an intake-related effect that is considered by EPA or state water quality permitting agencies in the development of the NPDES permits and 316(b) determinations. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through cooling systems. For this reason, the impingement of fish and shellfish is a Category 2 issue [Reference 2, GEIS Section 4.2.2.1.3].

Based on the research literature, monitoring reports, and agency consultations, the potential for thermal discharges to cause thermal discharge effect mortalities is considered small for most plants. However, impacts may be moderate or even large at a few plants with once-through cooling systems. For example, thermal discharges at one plant are considered by the agencies to have damaged benthic invertebrate and seagrass communities in the effluent-mixing zone around the discharge canal; as a result, helper cooling towers have been installed to reduce the discharge temperatures. Because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions, this is a Category 2 issue for plants with once-through cooling systems [Reference 2, GEIS Section 4.2.2.1.4].

4.3.4 Analysis of Environmental Impact

The principal concerns with once-through cooling water systems relate to the impact of intake structure design on the entrainment of larval fish and the impingement of juvenile and adult fish, and the affect of thermal discharges on the aquatic ecology of the receiving water body. Entergy Operations has performed extensive environmental monitoring, including the ecological assessment of the affects of the ANO-1 once-through cooling water system. This monitoring was required by the original ANO-1 Technical Specifications until Amendment No. 72 was issued on March 11, 1983 (0CNA038315), deleting the requirement. Subsequent to the issuance of Amendment No. 72 to the ANO-1 Technical Specifications, Entergy Operations continued this monitoring on a voluntary basis. This monitoring included entrainment studies until 1988 and impingement studies until 1994. The results of these studies are summarized below. As a note, entrainment and impingement of shellfish is not an issue because there is no significant population of endemic shellfish species in the vicinity of ANO.

4.3.4.1 Impingement and Entrainment

Impingement

Fish impingement occurs when juvenile and adult fish, too large to be entrained, collect on the 3/8-inch mesh screens located at the intake structure. Mortality of fish that are impinged is high at many plants because impinged organisms are eventually suffocated by being held against the screen mesh or are abraded, which can result in fatal infections. The purpose of the impingement monitoring program was to provide sufficient information for the accurate determination of impingement impacts by ANO on fish populations in Lake Dardanelle.

During the period of study, the species composition, abundance and length/weight records for impinged fish were typically collected twice a week from April to September and three times a week from September to April. Representative samples of impinged fish were collected over a 24-hour period to provide accurate estimates of weekly, monthly, and annual impingement trends [References 8, 9, 10, 11 and 12].

During the monitoring period at ANO, the total number and biomass of fish impinged was variable from year to year based on the lake temperature during the winter months. Most impingement losses within any year occurred during the winter months. The impingement studies consistently showed that over 95 percent of the number of fish impinged annually were Gizzard Shad (*Dorosoma cepedianum*) and Threadfin Shad (*Dorosoma petenense*). Approximately 5 percent of impingement totals were composed of sunfish (*Lepomis* spp.), catfish (*Ictalurus* spp.), Freshwater Drum (*Aplodinotus grunniens*), White Bass (*Morone chrysops*), Crappie (*Pomoxis* spp.), and Largemouth Bass (*Micropterus salmoides*).

It was concluded that the major cause of fish impingement was the direct result of natural cold-stressed mortality of both Threadfin Shad and Gizzard Shad populations during the winter [Reference 13]. Threadfin Shad is a warm-water, introduced species to Lake Dardanelle and exhibits cold shock stress behavior at water temperatures below 54°F. Water temperatures in Lake Dardanelle normally drop below 35°F each winter season, well below the lethal threshold temperature of approximately 41°F for Threadfin Shad. Gizzard Shad are native to the region and exhibit cold shock stress behavior over a slightly lower temperature range. The lower lethal temperature threshold for Gizzard Shad is approximately 33°F.

Both populations of shad, as well as other important forage, sport, and commercial fish species, were also monitored in annual far-field investigations in Lake Dardanelle beyond the influence of ANO. The results of these studies also provided supporting evidence that significant fluctuations in local shad populations occur naturally in the lake and are directly related to low seasonal water temperatures [Reference 13]. It was concluded that impinged shad that accumulated at the ANO intake structure were either already dead and drifting in the intake area or were cold-stressed and unable to avoid the moderate flow rates at the intake screens. It was also concluded that Threadfin Shad and Gizzard Shad populations are able to reestablish themselves in the intake area and other areas of the lake each year.

During the course of impingement monitoring at ANO, it was also shown that no significant losses in the standing crop of other fish populations in Lake Dardanelle occurred due to impingement or seasonal cold stress mortality. In 1995, the Arkansas Game and Fish Commission concluded that impingement losses have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

Based on the impingement studies performed, no significant changes have occurred to native fish populations. In addition, no significant changes have been made to the operation of the ANO intake structure since construction. Previous studies indicate that continuation of the observed levels of impingement should not result in any significant adverse environmental impact during the period of extended operation.

Entrainment

Entrainment occurs when planktonic larval fish drifting in the lake are carried with cooling water through the intake screens, pumps, and steam condensers. High mortality to larval fish results from mechanical and hydraulic forces experienced within the cooling system. Although studies have shown some larval fish survive entrainment, it is usually assumed that 100 percent mortality occurs.

The entrainment of larval fish at ANO was monitored for several years [References 15 and 16]. The purpose of the entrainment monitoring program was to provide sufficient information for the accurate determination of entrainment impacts by ANO on fish populations in Lake Dardanelle. The objective of the monitoring program was to determine the species composition and abundance of larval fish entrained at ANO during the peak spawning period from April to June each year. Results of these studies were correlated with standing crop fish community data collected in a related study performed in several areas in Lake Dardanelle. The results of entrainment monitoring consistently showed that the impact of entrainment losses to fish populations in Lake Dardanelle were not significant. For most of the years monitored, over 95 percent of the larval fish entrained at ANO were Gizzard Shad and Threadfin Shad (*Clupeidae*). Approximately 5 percent of the entrainment losses were composed of other locally abundant fish populations such as Carp (*Cyprinidae*), Suckers (*Catostomidae*), and White Bass (*Morone chrysops*), and Freshwater Drum (*Aplodinotis grunniens*).

These studies demonstrated that entrainment losses did not adversely effect abundant Clupeidae populations, or any other population of fish or aquatic organisms, in Lake Dardanelle within the influence of the ANO intake structure. In 1995, the AGFC also concluded that entrainment losses have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

Based on the entrainment studies performed, no significant changes have occurred to native fish populations. In addition, no significant changes have been made to the operation of the ANO intake structure since construction. Previous studies indicate that continuation of the observed levels of entrainment should not result in any significant adverse environmental impact during the period of extended operation.

4.3.4.2 Heat Shock

Lake Dardanelle is used as the source of heat dissipation for the ANO-1 once-through cooling water system. The lake was constructed by the U.S. Army Corps of Engineers in 1966 as part of the McClellan-Kerr Arkansas River Navigation Project. The 50-mile long lake has a surface area of approximately 37,000 acres and a storage capacity of 486,000 acre-feet.

With four circulating water pumps in operation, the ANO-1 once-through cooling water system has a design flow of 1738 cfs and increases the temperature of ambient intake lake water a maximum of 15°F as it passes through the plant [Reference 1]. Heated cooling water is discharged to Lake Dardanelle through a 520-foot long canal and an 80-acre embayment of the lake.

Thermal discharge limits for ANO (Outfall 001) are currently established in NPDES Permit Number AR0001392, dated September 30, 1997 [See Attachment B]. Thermal effluent discharge limits for Outfall 001 are 110°F daily maximum and 105°F daily average. These limits apply to the point where the cooling water enters the 520-foot long discharge canal. Since 1973, when the facility was originally permitted to discharge cooling water to Lake Dardanelle, no violations of established thermal permit limits have occurred at ANO.

A specific condition of NPDES Permit No. AR0001392 requires the applicant to monitor water temperatures after the discharged cooling water passes through the discharge embayment (mixing zone) and enters the main channel of Lake Dardanelle. During the period from June to September, water temperatures are monitored twice a month at three locations in Lake Dardanelle within the influence of the ANO cooling water discharge. This monitoring is performed to ensure the thermal water quality standard for the lake is not exceeded.

The Arkansas Water Quality Standard for Lake Dardanelle is 95°F. Because water quality standards for temperature are being met in Lake Dardanelle, no Section 316(a) variance is required or needed. In support of previous conclusions by state and federal regulatory agencies and Entergy Operations [References 17 and 18], the AGFC also concluded in 1995, that thermal impacts from ANO have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

4.3.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations has operated both the cooling system and the water intake for ANO in a manner that has resulted in no significant adverse impacts on the aquatic communities of Lake Dardanelle. This result is evidenced by state and federal water quality and wildlife resource agencies concluding that the operation of ANO has had no significant adverse impacts on Lake Dardanelle. Therefore, impacts are small and mitigation measures were not further considered.

4.4 Ground-Water Use Conflicts (Ranney Wells)

4.4.1 Requirement [10CFR51.53(c)(3)(ii)(C)]

If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total onsite) of ground water per minute, an assessment of the impact of the proposed action on ground water use must be provided.

4.4.2 Analysis of Environmental Impact

There are no Ranney wells or other wells in use on the ANO site. Drinking water is supplied from the City of Russellville and service water is taken from Lake Dardanelle. Therefore, this issue is not applicable to ANO and analysis is not required.

4.5 Ground-Water Quality

4.5.1 Requirement [10CFR51.53(c)(3)(ii)(D)]

If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided.

4.5.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Sites with closed-cycle cooling ponds may degrade groundwater quality. For plants located inland, the quality of the groundwater in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses. See 10CFR51.53(c)(3)(ii)(D)."

4.5.3 GEIS Background

The extent of groundwater contamination by cooling ponds has not been documented at this time. Off-site groundwater monitoring is not standard practice at these sites, and there are no data with which to characterize the significance of potential off-site groundwater contamination. For those plants with cooling ponds located in a salt marsh, groundwater quality is not a significant concern because groundwater quality beneath salt marshes is too poor for human use. Because continued infiltration into the shallow aquifer will not change its groundwater use category (which is already restricted to industrial uses only) and because potential mitigation measures would be costly, no mitigation measures beyond those implemented during the current term license would be warranted. Therefore, for plants with cooling ponds located in salt marshes, this is a Category 1 issue. The impact on groundwater quality for plants with cooling ponds that are not located in salt marshes is a Category 2 issue [Reference 2, GEIS Section 4.8.3].

4.5.4 Analysis of Environmental Impact

ANO-1 uses once-through cooling as the heat dissipation system. It is not necessary to assess the impact of license renewal on groundwater quality for plants with cooling systems other than cooling ponds.

ANO does have an emergency cooling pond which would be used as an auxiliary heat dissipation system should the Lake Dardanelle water source be lost at the intake structure. This cooling pond is permitted by the ADEQ as NPDES Outfall 009, with all monitoring activities controlled under NPDES Permit Number AR0001392. The pond was excavated from an area of heavy clay and silty-clay soils that range from 13 to 24 feet deep. These soils, which have low hydraulic permeabilities [Reference 1], serve as an aquiclude, or impervious cap, over the water-bearing shale strata below, and prevent the upward flow of water from the shale strata and the downward percolation of surface water from the emergency cooling pond [Reference 19]. An additional clay liner was also installed during pond construction to maintain a low hydraulic gradient between the pond and underlying soils to ensure that leakage did not occur [Reference 20]. Rotenone (fish eradication), a biocide (zebra mussels), and a dechlorinating agent (oxidants) are periodically added to the pond. Entergy Operations concludes that ground-water contamination from the cooling pond is insignificant due to soil bearing formations. In addition, the ground-water under the pond flows in the direction of Lake Dardanelle.

4.5.5 Consideration of Alternatives for Reducing Adverse Impacts

Since ANO-1 utilizes once-through cooling water from Lake Dardanelle as the primary heat dissipation system and offsite groundwater quality is unaffected by the emergency cooling pond due to the soil bearing formations, mitigation measures for reducing or avoiding this type of adverse environmental effect were not considered further.

4.6 Refurbishment Impacts on Important Plant and Animal Habitats, and Threatened or Endangered Species

4.6.1 Requirement [10CFR51.53(c)(3)(ii)(E)]

All license renewal applicants shall assess the impact of refurbishment and other license renewal related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

4.6.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application. See 10CFR51.53(c)(3)(ii)(E)."

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected. See 10CFR51.53(c)(3)(ii)(E)."

4.6.3 GEIS Background

The issue of impacts to threatened or endangered species is potentially relevant to all cooling system types and to transmission lines. Review of power plant operations has shown that neither current cooling system operations nor electric power transmission lines associated with nuclear power plants are having significant adverse impacts on any threatened or endangered species. However, widespread conversion of natural habitats and other human activities continues to cause the decline of native plants and animals. As biologists review the status of species, additional species threatened with extinction are being identified; consequently, it is not possible to ensure that future power plant operations will not be found to adversely affect some currently unrecognized threatened or endangered species.

In addition, future endangered species recovery efforts may require modifications of power plant operations. Similarly, operations-related land-disturbing activities (e.g., spent fuel and low-level waste storage facilities) could affect endangered species. As noted in GEIS Section 3.2, without site-specific and project-specific information, the magnitude or significance of impacts on threatened and endangered species cannot be assessed. For these reasons, the nature and significance of nuclear power plant operations on as yet unrecognized endangered species cannot be predicted; and no generic conclusion on the significance of potential impacts on endangered species can be reached. The impact on threatened and endangered species, therefore, is a Category 2 issue [Reference 2, GEIS Section 4.1].

Potential impacts of refurbishment on federal- or state-listed threatened and endangered species, and species proposed to be listed as threatened or endangered, cannot be assessed generically because the status of many species is being reviewed and it is impossible to know what species that are threatened with extinction may be identified that could be affected by refurbishment activities. In accordance with the Endangered Species Act of 1973 (Pub. L. 93-205), the appropriate federal agency (either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service) must be consulted about the presence of threatened or endangered species. At that time, it will be determined whether such species could be affected by the refurbishment activities and whether formal consultation will be required to address the impacts. Each state should be consulted about its own procedures for considering impacts to state-listed species. Because compliance with the Endangered Species Act cannot be assessed without site-specific consideration of potential effects on threatened and endangered species, it is not possible to determine generically the significance of potential impacts to threatened and endangered species. This is a Category 2 issue [Reference 2, GEIS Section 3.9].

4.6.4 Analysis of Impacts from Refurbishment Activities on Important Plant/Animal Habitats

There are no major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

4.6.5 Analysis of Impacts of the Proposed Action on Threatened or Endangered Species

4.6.5.1 Federal-Listed Species

Two mammal and four bird animal species currently protected under the Endangered Species Act have geographic ranges that possibly include the ANO site area. These include the Florida panther (*Felis concolor coryi*), bald eagle (*Haliaeetus leucocephalus*), red-cockaded woodpecker (*Picoides borealis*), interior least tern (*Sterna antillarum*), gray myotis (*Myotis grisescens),* and Bachman's warbler (*Vermivora bachmanii*). Of these species, the bald eagle is currently listed as threatened with the remaining species listed as endangered. Only the bald eagle is known to occasionally frequent the ANO site area. Suitable habitat for the other five species is not found within or near project boundaries, and none has been reported from the project area. No federally-listed fish, reptiles, amphibians, or invertebrate species or appropriate habitats for them have been identified within the ANO site area. In addition, no federally-listed plant species having a potential for occurrence has been identified within the ANO site area.

There are no recent records for the Florida panther in Arkansas, although the state was included in its historical range [Reference 21]. U.S. Fish and Wildlife Service reports that it is "highly unlikely that viable populations of the Florida panther presently occur outside Florida" [Reference 22].

Suitable roosting and feeding habitat for the bald eagle probably does not exist within the ANO site area, although a potential for occasional stray birds to fly within the site area possibly exists during winter months. A small resident population may occur in the Arkansas River Valley region, but there is no evidence of suitable nesting habitat within the site area. A bald eagle nest site was reported at a distance of approximately 10 miles from the site area several years ago, but it is not known whether the nest had some potential for nesting or whether it represented a practice nest by a juvenile bird. Bald eagle nests typically are placed in very large living trees and away from heavily impacted sites. No trees having a potential to serve as suitable nesting sites have been identified within the site area.

There are historical records of the red-cockaded woodpecker in Yell County at distances of approximately 40 miles from the ANO site area [References 23 and 24]. The species is no longer present at those localities, however, and the closest remaining colonies of birds are in Scott County at a distance of greater than 40 miles from the site area [Reference 25]. Suitable habitat does not exist for this species in the site area; therefore, it is not expected to be present.

The interior least tern requires exacting sand bar conditions, i.e., sand bars in the Arkansas River having very low vegetation cover and affording some protection from predators and flooding [Reference 24]. These habitat conditions are not present within the site area.

Bachman's warbler continues to appear on the list of federally-listed species occurring in Arkansas. Inclusion of the species on the Arkansas list is based on historical records, however, and the species is almost certainly extinct throughout its range. If still to be found at any location, this species is probably to be expected only in South Carolina [Reference 22].

Critical habitat has not been designated in Arkansas by the U.S. Fish and Wildlife Service for any of the six species, i.e., Florida panther, gray myotis, and the four bird species [Attachment C]. A formal onsite survey at ANO was not required by the U.S. Fish and Wildlife Service.

In addition, the U.S. Fish and Wildlife Service was contacted [Attachment C] to identify any new information regarding federally-listed species along the transmission lines that were constructed to support ANO-1. No records of any federally-listed species were identified.

4.6.5.2 State-Listed Species

The ANHC was contacted for information regarding state-listed threatened and endangered species in the vicinity of ANO. Although ANHC has no regulatory or enforcement authority, it is the state agency designated to maintain the Arkansas list of state threatened species, state endangered species, and a diverse inventory of other elements (important plant, animal, and habitat records). ANHC applies the term "state threatened" to native species that are believed likely to become endangered in Arkansas in the foreseeable future, based on current inventory information. ANHC applies the term "state endangered" to native species that are in danger of being extirpated from the state. The state-level threatened and endangered species lists for Arkansas contain no animal species and only a limited number of plant species. No state-listed threatened or endangered plant species were identified in the records of ANHC for the ANO site [Attachment D].

In addition to state-level threatened and endangered species lists, other elements in the ANHC inventory include records such as outstanding examples of natural communities, colonial nesting sites, outstanding scenic, and geologic features. The inventory also contains information regarding plants and animals that may be federally-listed as threatened or endangered, rare in Arkansas, peripheral (i.e., around the borders of Arkansas) to Arkansas, or of an undetermined status in the state. A list of element occurrences for Pope County was obtained from the inventory records maintained by ANHC [Attachment D]. Seven database elements of special concern to ANHC have been reported to occur in the vicinity of ANO. These elements include the following plant and animal species and habitat types: Rafinesque's big-eared bat (*Corynorhinus rafinesquii*), gray myotis (*Myotis grisescens*), longnose darter (*Percina nasuta*), Northern crayfish frog (*Rana areolata circulosa*), Riddell's spike moss (*Selaginella riddellii*), Ozark spiderwort (*Tradescantia ozarkana*), and sandstone glade/outcrop habitat. None of these seven elements are classified as state-level threatened or endangered species.

Of the species in the ANHC inventory for Pope County having known occurrences on the Russellville West topographic quadrangle map, suitable habitat possibly exists within the site area for one of them, the Northern crayfish frog. The Northern crayfish frog is not a state listed species, but it represents a species that has been tracked by ANHC for several years as an S1 species [Reference 26]. ANHC defines a S1 species as "extremely rare" and "may be especially vulnerable to extirpation." In May 1999, Dr. Stanley E. Trauth (an Arkansas herpetofauna authority) recommended to ANHC that the Northern crayfish frog's ranking should be changed to S3 [Reference 27]. ANHC defines S3 species as "Rare to uncommon; typically between 20 and 100 estimated occurrences, may have fewer occurrences but with large number of individuals in some populations, may be susceptible to large-scale disturbances." Dr. Trauth assessed the State Protection Needs for the species as "none at the present time," and based on his recommendations, there does not appear to be cause for concern for the Northern crayfish frog at the site area.

The ANO site area also contains a very few small areas of sandstone glade/outcrop habitat, which represents an element tracked by the ANHC but which is afforded no protection under state or federal law. Since these small areas of sandstone/glade habitat have already been impacted during initial construction activities, they have likely lost their original habitat value.

The ANHC staff agreed that ANO represents an industrial site that has experienced alteration of much of its original vegetation cover and natural habitat value. Therefore, the probability of identifying any of the seven elements of special concern on the ANHC inventory would be remote and not justify an on-site survey at ANO [Attachment D].

The ANHC and Arkansas Game and Fish Commission were also contacted [Attachments D and E] to identify any new information regarding state-level threatened and endangered species along the transmission lines that were constructed to support ANO-1. No records of any state-listed threatened species, endangered species, or any other species of concern were identified.

4.6.5.3 Conclusion of Impacts

The continued operation of ANO-1 will not impact threatened and endangered species because no federally-listed or state-listed threatened and endangered species, other important species, or habitats of concern to the state are known to exist at the site. Correspondence with the U.S. Fish and Wildlife Service and the Arkansas Natural Heritage Commission relative to special status species issues is provided in Attachments C and D.

4.6.6 Consideration of Alternatives for Reducing Adverse Impacts

There are no major refurbishment activities required for license renewal at ANO-1 [See Section 3.2]; therefore, no analysis of the impact of this issue is required. In addition, no federally-listed or state-listed threatened and endangered species, other important species, or habitats of concern to the state are known to exist at the site or along the transmission lines. Therefore, there are no impacts necessitating consideration of alternatives.

4.7 Vehicle Exhaust Emissions

4.7.1 Requirement [10CFR51.53(c)(3)(ii)(F)]

If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended.

4.7.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage. See 10CFR51.53(c)(ii)(3)(F)."

4.7.3 Analysis of Environmental Impact

ANO is not located in, or near, a nonattainment or maintenance area for air pollutants, from either the federal or state regulatory standpoint. The nearest nonattainment areas to ANO are the Dallas/Ft. Worth, Texas metropolitan area, over 300 miles southwest of the site, and the Memphis, Tennessee metropolitan area located approximately 200 miles east of the site. Additionally, there are no major refurbishment activities required for license renewal at ANO-1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

4.8 Microbiological (Thermophilic) Organisms

4.8.1 Requirement [10CFR51.53(c)(3)(ii)(G)]

If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than $3.15x10^{12}$ ft^3/year ($9x10^{10}m^3$/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided.

4.8.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically. See 10CFR51.53(c)(3)(ii)(G)."

4.8.3 GEIS Background

Public health questions require additional consideration for the 25 plants using cooling ponds, lakes, canals, or small rivers because the operation of these plants may significantly enhance the presence of thermophilic organisms. The data for these sites are not now at hand and it is impossible to predict the level of thermophilic organism enhancement at any given site with current knowledge. Thus, the impacts are not known and are site-specific. Therefore, the magnitude of the potential public health impacts associated with thermal enhancement of *N. fowleri* cannot be determined generically. This is a Category 2 issue [Reference 2, GEIS Section 4.3.6].

4.8.4 Analysis of Environmental Impact

ANO was one of eleven nuclear plants in 1981 that participated in a study regarding the possible presence of thermophilic pathogens in cooling water systems [References 28, 29, and 30]. In addition, ANO was one of ten sites where thermophilic free-living amoebae were detected. Tests indicated, however, that the amoebae were not pathogenic as *Naegleria* sp. was not detected in water and sediment samples collected from the ANO intake canal or discharge embayment. *Legionella* was detected in water samples collected at ANO (Lake Dardanelle) and several control sources of surface water in the area. Concentrations of *Legionella* in the ANO cooling water systems were similar to concentrations in local surface water control sources.

Studies regarding the presence of thermophilic pathogens at ANO concluded that any risk for infection from contact with aerosols containing *Legionella* sp. was an industrial hygiene concern that could be effectively managed using standard industrial hygiene practices. No concerns regarding public exposure to aerosols containing *Legionella* were identified. Because pathogenic *Naegleria* sp. was not detected in samples collected from Lake Dardanelle or the ANO discharge embayment, the human health risks associated with this microorganism were considered to be very low or insignificant. No specific studies were developed to address the possible presence of naturally occurring thermophilic microorganisms such as *Salmonella, Shigella, Aeromonas,* and *Pseudomonas* at ANO.

The ADH was contacted to identify any possible concerns state health officials had concerning waterborne thermophilic pathogens in Lake Dardanelle and the Arkansas River system. Several officials, including the State Epidemiologist, indicated that no information was available to indicate that a human health exposure problem exists with thermophilic pathogens in Lake Dardanelle or the Arkansas River [Reference 31]. They noted that one case, reported in approximately 1980, involved an individual who died soon after contracting amoebic meningoencephalitis. Public health officials suspected the victim's swimming in warm, shallow water in the Arkansas River may have lead to the infection. The cause of the disease and its source were never confirmed. The suspected location of the contaminated river water was approximately 175 miles downstream from ANO.

There has been no known impact of ANO-1 operation on public health related to thermophilic microorganisms. Since no changes are planned to the operation of the cooling water discharge, no such impact is likely to occur as a result of license renewal.

4.8.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations complies with the directives issued by the ADH regarding public health, thermophilic organisms, and their relationship to ANO-1 operation. No mitigation measures beyond those required by ADH during the current term of ANO-1 operation would be expected as a result of license renewal.

4.9 Electrical Shock from Induced Currents

4.9.1 Requirement [10CFR51.53(c)(3)(ii)(H)]

If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant[6] to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided [10CFR51.53(c)(3)(ii)(H)].

4.9.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electrical shock potential at the site[7]. See 10CFR51.53(c)(3)(ii)(H)."

4.9.3 GEIS Background

The transmission lines of concern are those between the plant and the intertie to the transmission system. With respect to shock safety issues and license renewal, three points must be made. First, in the licensing process for the earlier licensed nuclear plants, the issue of electrical shock safety was not addressed. Second, some plants that received operating licenses with a stated transmission line voltage may have chosen to upgrade the line voltage for reasons of efficiency, possibly without reanalysis of induction effects. Third, since the initial NEPA review for those utilities that evaluated potential shock situations under the provision of the NESC, land-use may have changed, resulting in the need for reevaluation of this issue.

[6] The plant is defined as the nuclear reactors, steam-electric systems, intakes, discharges, and all other on-station facilities involved in the production of electricity. Transmission lines and other off-station facilities are not part of the plant. (NUREG-1555, Standard Review Plan for Environmental Reviews for Nuclear Power Plants, Introduction Chapter, Definitions, February 1999)

[7] The site is considered to be synonymous with 'Station', which is defined as all facilities (reactors, control buildings, intakes, discharges, etc.) that are located on the applicant's site. Transmission lines and their associated facilities are not considered part of the station. (NUREG-1555, Standard Review Plan for Environmental Reviews for Nuclear Power Plants, Introduction Chapter, Definitions, February 1999)

The electrical shock issue, which is generic to all types of electrical generating stations, including nuclear power plants, is of small significance for transmission lines that are operated in adherence with NESC. Without review of each nuclear plant's transmission line conformance with NESC criteria, it is not possible to determine the significance of the electrical shock potential. This is a Category 2 issue [Reference 2, GEIS Sections 4.5.4 and 4.5.4.1].

4.9.4 Analysis of Environmental Impact

To connect the ANO-1 nuclear unit into the transmission system required construction of four transmission lines in the early 1970's. These lines are shown in Figure 4.9-1 and are listed in Table 4.9-1.

The transmission lines in Table 4.9-1 have remained at the same operating voltage levels since the ANO units were placed into service. These transmission lines have not been upgraded to operate at higher voltage levels and have not been moved since their initial installation. The clearances along these transmission lines were initially designed for most land uses (i.e., county roads, farm machinery, etc.). Since Entergy Arkansas holds easements to the land beneath the transmission lines and monitors these transmission lines by aerial surveillance during the year, Entergy Arkansas controls the land use. If the ANO units were removed from service, these transmission lines would have to remain in service to provide power for the area transmission loads due to the significant increase in area loads since the construction of the ANO units.

To provide a safeguard for persons who may be in close proximity to electric power lines, the National Electrical Safety Code identifies minimum vertical clearances for electric lines operating at various voltage levels. Regulatory bodies usually require that utilities construct transmission lines according to either the latest edition of the NESC or to a specified edition adopted by the body; however, they do not require existing transmission lines to be upgraded to meet revisions of the code. In addition, the NESC does not require maintenance replacements to comply with latest code, unless a structure is replaced. Vertical clearance to facilities on the pole are required to have current code dimensions (for example, communication lines, transformers, etc.).

The two 500 kV transmission lines (48 miles) presently meet the 1997 NESC clearances of 28.35 feet at a maximum operating temperature of 212°F.

The two 161 kV transmission lines (built for ANO-1 which total 50 miles in length) are composed of aluminum conductors and were constructed in 1971 in compliance with the then applicable sixth edition of the NESC (1961). When initially installed, these transmission lines were designed for 26 feet clearance at a temperature of 120°F. The loadings on these transmission lines have increased since the initial installation, resulting in increased conductor temperatures and increased sag. Since installation, these ground clearances could decrease to less than 21 feet at maximum possible conductor operating temperatures (a clearance value required in the 1997 NESC). Consequently, these two transmission lines might not presently meet the 1997 NESC requirements for clearance (21 feet to ground) during certain limited transmission line outages, which result in maximum possible conductor operating temperatures. However, the transmission lines continue to meet the previous code (1961) to which they were constructed. The clearances to ground currently exceed the height of vehicles expected to pass under these lines. Also, to Entergy-Arkansas' knowledge, no incidents of electric shock have been reported from these lines since they were placed into service.

The earlier standards, to which these four transmission lines were constructed, did not specifically address electric shock that could be experienced by a person contacting a large vehicle parked under the transmission lines. This was added to the more recent NESC editions which states that for voltages exceeding 98 kV to ground (169.7 kV phase to phase), either the clearance must be increased or the effects thereof shall be reduced by other means, as required, to limit the steady-state current due to electrostatic effects to 5 mA (root-mean-square), if the largest anticipated truck, vehicle, or equipment under the transmission line were short-circuited to ground. The size of the anticipated truck, vehicle, or equipment used to determine the clearances may be less than, but need not be greater than, that limited by federal, state, or local regulations governing the area under the transmission line. For this determination, the conductors shall be at a final unloaded sag of 50°C (120°F).

The necessary studies have been performed to determine whether the two 500 kV transmission lines built for ANO-1 have adequate clearances to limit the steady-state current for the largest anticipated truck parked under the transmission line to the 5-mA limit. The 161 kV transmission lines were excluded from this study since their voltages to ground do not exceed 98 kV to ground and therefore, do not apply to this NESC code requirement (Note - the 161 kV transmission lines do not generate an electric field of enough magnitude to cause a shock hazard).

EPRI has published a reference book [Reference 32] and has developed a computer code called ENVIRO [Reference 33], which together are used to calculate the steady-state current value from transmission lines. The calculation is a two-step process in which the analyst calculates the average field strength at one meter (3.28 feet) above the ground beneath the minimum line clearance, and then calculates the steady-state current value.

The two 500 kV transmission lines were evaluated for this 5-mA standard. The largest vehicle that would routinely be anticipated being under these 500 kV transmission lines is a tractor-trailer (75 feet long, 8.5 feet wide, and 13.5 feet high) parked on or alongside the roadway. These transmission line clearances, together with transmission line characteristics such as voltage and conductor position, have been entered into the ENVIRO code, to obtain electric field strengths at one-foot intervals, one meter above the ground. The maximum calculated average field strength is determined (in kV per meter) while placing a 75-foot object under and perpendicular to the transmission lines (representing a large tractor-trailer rig). Using the maximum average field strength, in accordance with the EPRI reference book, the steady-state current for a tractor trailer

75 feet long, 8.5 feet wide, and 13.5 feet high at the road crossings under these two 500 kV transmission lines was calculated. The resultant values were found to be greater than the 5-mA limit established by the NESC for three of the nine major road crossings. The highest level of 5.54 mA appeared at a 500 kV crossing having a 37.2 feet clearance at 120°F and an average maximum field strength of 6.03 kV/meter. However, for these few situations, it is not deemed necessary to take any mitigating measures for these road crossings for the following reasons:

- The likelihood that a large truck would park in perfect orientation directly under one of the nine major road crossings on this 48 miles of 500 kV transmission lines is remote.

- Although the 1997 NESC uses 5 mA as a limit, this value would not actually flow through a person touching such a vehicle. The actual flow of current would be a small fraction of the 5 mA limit and would not result in any safety concern for an adult or child. The 5 mA value could only occur when the vehicle is perfectly insulated and the person is perfectly grounded. Research has shown [Reference 32] that for a large school bus, the median value of short-circuit current through a body touching the school bus is only 1 to 4 percent of the calculated short-circuit level. Thus, if 5 mA were calculated (a value conservatively used as a let-go current level for children), then the average person would only have 0.05 to 0.2 mA flowing through his body. This 0.05 to 0.2 mA value is not perceptible for the average adult and would at most be "perceptible without shock" to a child. As is stated in this reference, "if the line is designed according to code (i.e., within the 5 mA. short-circuit limit), short-circuit currents to a person would be below minimum perception levels." Therefore, it is not believed that there is a need to modify the two 500 kV transmission lines (at the three crossings) that exceed the 5 mA limit by at most 10.8 percent, when contact with this large vehicle would result in a shock that would be barely perceptible.

- Without a transmission line change or planned modification to the transmission line as specified within the NESC Code, it is not normally the policy to reconstruct existing facilities (that were initially built to applicable code standards) in order to meet later or more restrictive code standards. The NESC does not require utilities to modify existing facilities to comply with later revisions of the code as long as those facilities complied with prior editions of the code except as possibly required by the administrative authority.

For off-the-road clearances, the minimum clearance for the two 500 kV transmission lines was found to be 35 feet at 120°F. At the maximum operating transmission line temperature of 212°F, this clearance would meet the NESC requirement of 28.35 feet. In addition, a very large school bus (40 feet long by 11 feet high by 8 feet wide) was placed at an off-road location to simulate the largest possible vehicle or agriculture combine that possibly might be located in a field location. The resultant calculations determined that the short circuit currents for this large school bus were 3.95 mA, which is less than the 5 mA 1997 NESC limit.

It should also be noted that the ANO generating plant is located in close proximity to the ANO switchyard, where the above transmission lines are terminated. A 500 kV transmission line connects the ANO-1 generator to this switchyard. Additionally, a short 161 kV transmission line runs from the plant to this switchyard for offsite power requirements. These transmission lines are very short, less than 1600 feet, and meet the 1997 NESC requirements for clearance and electric shock for large vehicles.

4.9.5 Consideration of Alternatives for Reducing Adverse Impacts

Based on the above information, the impact of the potential for electric shock is small. Since these four transmission lines would remain in-service regardless of license renewal, license renewal will have no impact on shock hazard. Further, the potential for shock hazard is not significant, and mitigation is not considered to be warranted.

Table 4.9-1, Transmission Lines Built for Installation of ANO-1

Line Description	Voltage	Distance (Miles)	Year Line Was Energized
Tap on Ft. Smith-Mabelvale Line Connection of ANO-1 to Mabelvale	500 kV	24.16	1971
Tap on Ft. Smith-Mabelvale Line Connection of ANO-1 to Fort Smith	500 kV	24.07	1971
ANO-1 - Morrilton East	161 kV	38.89	1971
ANO-1 - Russellville East	161 kV	11.98	1971
TOTALS	500 kV 161 kV	48.23 50.87	

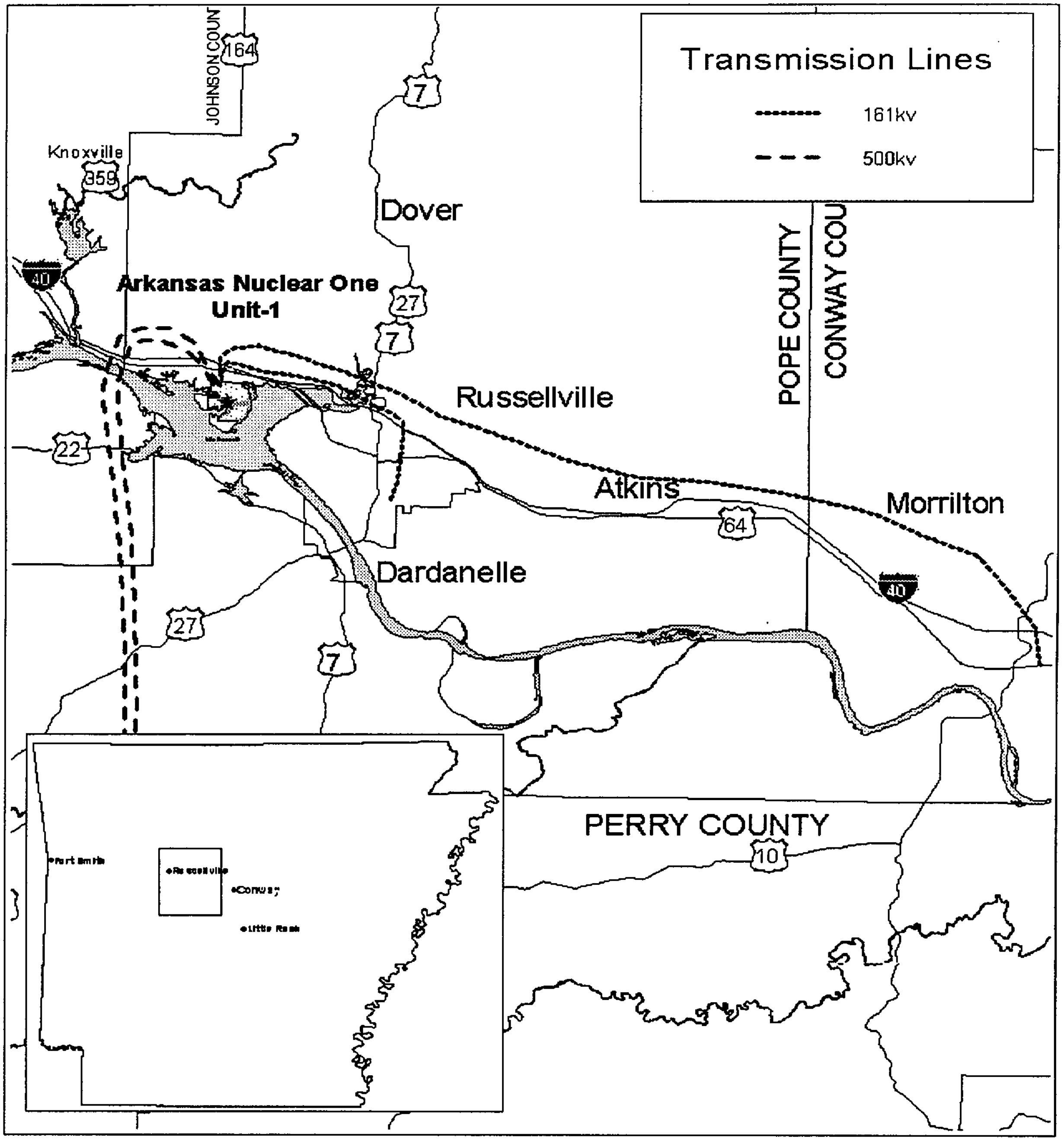

Figure 4.9-1, Transmission Lines from ANO-1 to the Transmission System

4.10 Housing, Land-Use, Public Schools and Public Water Supply Impacts

4.10.1 Requirement [10CFR51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

4.10.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or in areas with growth control measures that limit housing development. See 10CFR51.53(c)(3)(ii)(I)."

"An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. Impacts may be of moderate significance at plants in low population areas."

"Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10CFR51.53(c)(3)(ii)(I)."

4.10.3 Estimates of Workforce During the License Renewal Term

The socioeconomic impacts of license renewal are addressed in the GEIS; in particular see Volume 1, Section 3.7, and Section 4.7. Volume 2 of the GEIS, Appendix C (Socioeconomics) includes the results of a case study, for the area around ANO, of the socioeconomic impacts associated with refurbishment activities and continued operation during the license renewal term. In GEIS Appendix C, Section C.4.1, the impact of estimated increases in staff at ANO is evaluated in terms of the population of Pope County. The 1990 census showed the population of Pope County to be 45,883 persons. The Census Bureau estimate of the 1997 population for Pope County is 51,219.

The GEIS assumes that an additional staff of 60 permanent workers will be required during the license renewal period. This evaluation also accounted for indirect employment and for in-migration of workers and their families to Pope County. The evaluation found that the increase would represent less than 0.3 percent of Pope County's population in 2014. Entergy Operations has not identified any increases in staffing related to license renewal-related programs; therefore, there would be no corresponding increase in direct or indirect workers in Pope County due to the proposed action. Therefore, the GEIS evaluation overestimates the increase in staff at ANO-1 during the license renewal term.

Housing Availability - GEIS Background

The impacts on housing are considered to be of small significance when a small and not easily discernible change in housing availability occurs, generally as a result of a very small demand increase or a very large housing market. Increases in rental rates or housing values in these areas would be expected to equal or slightly exceed the statewide inflation rate. No extraordinary construction or conversion of housing would occur where small impacts are foreseen.

The impacts on housing are considered to be of moderate significance when there is a discernible but short-lived reduction in available housing units because of project-induced in-migration. The impacts on housing are considered to be of large significance when project-related demand for housing units would result in very limited housing availability and would increase rental rates and housing values well above normal inflationary increases in the state.

Moderate and large impacts are possible at sites located in rural and remote areas, at sites located in areas that have experienced extremely slow population growth (and thus slow or no growth in housing), or where growth control measures that limit housing development are in existence or have been recently lifted. Because impact significance depends on local conditions that cannot be predicted at this time, housing is a Category 2 issue [Reference 2, GEIS Section 3.7.2].

Analysis of Impact of the Proposed Action on Housing Availability

The GEIS, Volume 2, Appendix C, Table C.21, indicates that in the year 2013, the projected direct and indirect plant related employment at ANO will be 2964 persons. This is 8.9 percent of the total Pope County employment, as indicated in GEIS Table C.21. The GEIS estimated that an additional 60 workers would be required at ANO-1 during the license renewal period and that this would cause only small new housing impacts. Based on a site-specific review, the impact of license renewal on housing availability is expected to be even smaller than that discussed in the GEIS. Since no major refurbishment activities have been identified, and there is no identified need to increase plant staff for the period of extended operation, impact on housing availability is expected to be very small.

Land-Use - GEIS Background

The issue evaluated in this section concerns refurbishment-induced changes to local land use and development patterns. Because the value attributed to land-use changes can vary for different individuals and groups, this analysis does not attempt to conclude whether such changes have positive or negative impacts. The impacts to off-site land use are considered small if population growth results in very little new residential or commercial development compared with existing conditions and if the limited development results only in minimal changes in an area's basic land-use pattern. Land-use impacts are considered to be moderate if plant-related population growth results in considerable new residential or commercial development and the development results in some changes to an area's basic land-use pattern. The impacts are considered to be large if population growth results in large-scale new residential or commercial development and the development results in major changes in an area's basic land-use pattern. Based on predictions for the case study sites, refurbishment at all nuclear plants is expected to induce small or moderate land-use changes. There will be new impacts, but for almost all plants, refurbishment-related population growth would typically represent a much smaller percentage of the local areas' total population than did original construction-related growth. Because future impacts are expected to range from small to moderate, and because land-use changes could be considered beneficial by some community members and adverse by others, this is a Category 2 issue [Reference 2, GEIS Section 3.7.5].

Based on predictions for the case study plants, it is projected that all new population-driven land-use changes during the license renewal term at all nuclear plants will be small because population growth caused by license renewal will represent a much smaller percentage of the local area's total population than has operations-related growth. Also, any conflicts between offsite land use and nuclear plant operations are expected to be small. In contrast, it is projected that new *tax-driven* land-use changes may be moderate at a number of sites and large at some others. Because land use changes may be perceived by some community members as adverse and by others as beneficial, the staff is unable to assess generically the potential significance of site-specific off-site land use impacts. This is a Category 2 issue [Reference 2, GEIS Section 4.7.4.2].

Analysis of Impact of the Proposed Action on Land-Use

Appendix C of the GEIS contains an analysis of land-use for the area around ANO. This analysis evaluated the direct and indirect land-use impacts resulting from the extension of the license, and concluded that: "With the plant-related population increase projected for Pope County, the land-use impacts of ANO refurbishment are expected to be small."

"The indirect land-use impacts of ANO-1's license renewal term are expected to be moderate. Population growth associated with the plant's continued operation is projected to represent only a 0.3 percent increase in Pope County's projected 2014 population, so the new land-use impacts of worker in-migration are expected to be minimal. However, key sources expect residential development to continue on the peninsula because of the availability of desirable lakefront property. As in the past, this continued residential development would be guided by the provision of roads and water service, an indirect impact of ANO's presence. The plant's operation also would result in continued economic benefits such as direct and indirect salaries and tax contributions for Pope County. But the tax benefits may be less than those previously available because of Amendment 59, which in the mid-to-late 1980's caused reductions in tax payments on utility property. Nonetheless, ANO-1's operation would provide Pope County with economic benefits that would continue to shape land-use and development patterns in Russellville and the rest of the county through the provision of municipal services" [Reference 2, GEIS, Volume 2, Appendix C, C.4.1.5.2 Predicted Impacts of License Renewal]. Entergy Operations accepts the GEIS evaluation and no further evaluation is required.

Analysis of Impact of Refurbishment Activities on Public Schools

There are no identified major refurbishment activities required for license renewal at ANO-1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

Public Water Supply - GEIS Background

Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as the quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services. In general, small to moderate impacts to public utilities were observed as a result of the original construction of the case study plants. While most locales experienced an increase in the level of demand for services, they were able to accommodate this demand without significant disruption. Water service seems to have been the most affected public utility.

Public utility impacts at the case study sites during refurbishment are projected to range from small to moderate. The potentially small to moderate impact at Diablo Canyon is related to water availability (not processing capacity) and would occur only if a water shortage occurs at refurbishment time. Because the case studies indicate that some public utilities may be overtaxed during peak periods, the impacts to public utilities would be moderate in some cases, although most sites would experience only small impacts. This is a Category 2 issue [Reference 2, GEIS Section 3.7.4.5].

Analysis of Impact of the Proposed Action on Public Water Supply

The impact on public utilities attributable to population increases from the proposed action is evaluated in GEIS, Volume 2, Appendix C, Section C.4.1.4.2 (Predicted Impacts of License Renewal). The following excerpt is from that source: "...the public water system may be moderately affected because of the diminishing local water supply and increasing water usage by the plant."

License renewal is not projected to cause a noticeable effect on the Russellville water supply. Historically, the water system has used the Illinois Bayou and, on occasion, Lake

Dardanelle as a source of water. In 1997, the City of Russellville completed the construction of a new water supply source, the Huckleberry Creek Reservoir. This new reservoir significantly increased the water system storage capacity and provides residential and industrial customers in the area with a reliable supply of high quality water for many years. Plans are also being made to double the current water treatment processing capacity of 10 million gallons per day.

ANO is currently the third largest water consumer on the Russellville water system, with an average consumption of approximately 100,000 gallons per day. The facility is connected to the water system by way of a 1,000,000 gallon storage tank located north of the facility. Eighty percent of the capacity of the tank is reserved for ANO with the remaining amount assigned to meet the needs of the City of London, Arkansas.

During normal plant operations, the amount and quality of water available to ANO from the Russellville water system is adequate to meet the facility's operational needs. During infrequent start-up periods, however, the short-term demand for water by ANO increases significantly and has caused noticeable affects on the local water distribution system. To reduce this affect, Entergy Operations completed modifications in 1997 that will now provide the facility with a supplementary source of water for start-up periods. This modification now allows water to be pumped from Lake Dardanelle, treated, and stored on-site for use during intermittent periods of high consumption. Therefore, the construction of the new water reservoir combined with the ANO facility modification, has not only minimized impacts to the public water supply system, but has also ensured that an adequate water supply will be available in the future.

4.10.4 Consideration of Alternatives for Reducing Adverse Impacts

The impacts from the proposed action on housing availability and public schools were evaluated in the GEIS and determined to be small. The impacts of the proposed action on land-use were also evaluated in the GEIS. The direct land-use impacts were found to be small, while the indirect land-use impacts (additional roads and water service) were found to be moderate. These identified impacts were found to be favorable and similar to the impacts that ANO plant operations has had on the community to date. Entergy Operations agrees with this determination, and therefore, mitigation measures for reducing or avoiding adverse environmental effects need not be considered. In addition, the construction of the new water reservoir combined with the ANO facility modification, has not only minimized impacts to the public water supply system, but has also ensured that an adequate water supply will be available in the future. Therefore, impacts to public water supply are small and mitigation measures were not considered further.

As discussed in GEIS Appendix C, Section C.4.1.3.2, one of the most significant impacts of ANO, since the start of operations in 1974, has been the benefit provided by the amount of property taxes paid by Entergy Operations to Pope County. License renewal would allow the county to continue to receive property taxes from the operating nuclear station for up to 20 additional years beyond the current license expiration.

4.11 Local Transportation Impacts

4.11.1 Requirement [10CFR51.53(c)(3)(ii)(J)]

All applicants shall assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license.

4.11.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. See 10CFR51.53(c)(3)(ii)(J)."

4.11.3 GEIS Background

Impacts to transportation during the license renewal term would be similar to those experienced during current operations and would be driven mainly by the workers involved in current plant operations. Based on past and projected impacts at the case study sites, transportation impacts would continue to be as small significance at all sites during operations and would be of small or moderate significance during scheduled refueling and maintenance outages. Because impacts are determined primarily by road conditions existing at the time of the project and cannot be easily forecast, a site-specific review will be necessary to determine whether impacts are likely to be small or moderate and whether mitigation measures may be warranted. This is a Category 2 issue [Reference 2, GEIS Section 4.7.3.2.].

4.11.4 Analysis of Environmental Impact

There are no identified major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]. In addition, the GEIS, Volume 2, Appendix C, Section C.4.1.4.2 (Predicted Impacts of License Renewal) contains an analysis of the local transportation impacts for the area around ANO. This analysis was based on adding additional workers for refurbishment activities. The following excerpt is from that source: "...During ANO construction, when the number of in-migrants peaked at 2756 (an 8.3 percent increase in Pope County population), there were small impacts on transportation, social services, public utilities, tourism, and recreation. Projected refurbishment-related in-migration (15 percent less than construction in-migration) will increase the population 3.7 percent. Therefore, projected impacts on these public services from refurbishment will be small."

4.11.5 Consideration of Alternatives for Reducing Adverse Impacts

Since no refurbishment activities have been identified and no additional workforce has been identified as needed during the license renewal period, impacts to local transportation will continue to be small. Therefore, mitigation measures were not considered further.

4.12 Historic and Archaeological Properties

4.12.1 Requirement [10CFR51.53(c)(3)(ii)(K)]

All applicants shall assess whether any historic or archaeological properties will be affected by the proposed project.

4.12.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection. See 10CFR51.53(c)(3)(ii)(K)."

4.12.3 GEIS Background

It is unlikely that moderate or large impacts to historic resources occur at any site unless new facilities or service roads are constructed or new transmission lines are established. However, the identification of historic resources and determination of possible impact to them must be done on a site-specific basis through consultation with the State Historical Preservation Office. The site-specific nature of historic resources and the mandatory National Historic Preservation Act consultation process mean that the significance of impacts to historic resources and the appropriate mitigation measures to address those impacts cannot be determined generically. This is a Category 2 issue [Reference 2, GEIS Section 3.7.7].

4.12.4 Analysis of Environmental Impact

ANO is located in the Arkansas River Valley. During construction of the plant, several minor sites were likely disturbed, although no records existed which indicated areas of archeological significance located within the site boundary. The Arkansas Archeological Survey Coordinating Office, the Arkansas State Parks and Tourism Commission, and the Arkansas State Historic Preservation Office were consulted during the construction and early operation of ANO for information regarding potential impacts to historic sites. In general, all sources indicated the construction and operation of ANO had only insignificant impacts on archeological sites and had no effect on historic structures listed in the Federal Register of Historic Places [Reference 1].

The SHPO was contacted [Attachment F] to identify any new information regarding sites of archeological, historical, or architectural significance on the ANO site. Although no historical or architectural sites were identified, five archeological sites of interest were reported to exist around ANO. However, none of these areas are close enough to existing facilities to warrant concern. The SHPO provided Entergy Operations with a map that identified these sites to ensure that their archeological value remains protected. Entergy Operations notifies the SHPO prior to any significant earth-moving activities in or near these areas. A formal onsite survey was not required by the SHPO [Attachment F].

To date, the construction and operation of ANO has had no significant impact to aesthetic resources of the local area. In addition, the plant's appearance has had no adverse impact on the residential or recreational land uses on Lake Dardanelle. Because no refurbishment activities have been identified for ANO-1 license renewal, no additional land is needed for the plant's use. In addition, the visible profile of the plant is not expected to change, and impacts on historic and aesthetic resources are expected to be much smaller than the insignificant impacts experienced during construction.

In addition, the SHPO was contacted [Attachment F] to identify any information regarding sites of archeological, historical, or architectural significance along the transmission lines that were constructed to support ANO-1. No historical or architectural issues were identified.

4.12.5 Consideration of Alternatives for Reducing Adverse Impacts

Continued operation of ANO-1 during the period of the renewed license will have no significant adverse impact on historic or archeological property. No refurbishment activities have been identified as being necessary to support continued operation of ANO-1 beyond the end of the existing operating license. Therefore, impacts on historic or archeological property are small.

4.13 Severe Accident Mitigation Alternatives

4.13.1 Requirement [10CFR51.53(c)(3)(ii)(L)]

If the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environmental assessment, a consideration of alternatives to mitigate severe accidents must be provided.

4.13.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives. See 10CFR51.53(c)(3)(ii)(L)."

4.13.3 GEIS Background

The staff concluded that the generic analysis summarized in the GEIS applies to all plants and that the probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to groundwater, and societal and economic impacts of severe accidents are of small significance for all plants. However, not all plants have performed a site-specific analysis of measures that could mitigate severe accidents. Consequently, severe accidents are a Category 2 issue for plants that have not performed a site-specific consideration of severe accident mitigation and submitted that analysis for Commission review [Reference 2, GEIS Section 5.5.2.5].

4.13.4 Analysis

The following sections present the SAMA analysis that was performed for ANO-1.

4.13.4.1 Methodology Overview

The methodology used to perform the ANO-1 SAMA analysis was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities, "Regulatory Analysis Technical Evaluation Handbook", NUREG/BR-0184, January 1997, subject to ANO-1 specific considerations.

Environmental impact statements and environmental reports are prepared using a sliding scale in which impacts of greater concern and mitigative measures of greater potential value receive more detailed analysis than impacts of less concern and mitigative measures of less potential value. Accordingly, Entergy Operations used less detailed feasibility investigative and cost estimation techniques for SAMAs having disproportionately high costs and low benefits and more detailed evaluations for the most viable candidates.

Initial input for the ANO-1 SAMA benefits analysis was the ANO-1 Probabilistic Safety Assessment model. This model is the ANO-1 internal events risk model and is an updated version of the Individual Plant Examination, "Arkansas Nuclear One Unit 1 Probabilistic Risk Assessment Summary Report," April 1993. Therefore, the SAMA analysis is based on ANO-1 modeling.

The following is a brief outline of the approach taken in the SAMA analysis:

<u>Establish the base case – Use NUREG/BR-0184 to evaluate severe accident impacts:</u>

- Offsite exposure costs – Monetary value of consequences (dose) to offsite population; use the ANO-1 PSA model to determine total accident frequency (core damage frequency and containment release frequency); Melcor Accident Consequences Code

System to convert release input to public dose; and NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

- Offsite economic costs – Monetary value of damage to offsite property; use the ANO-1 PSA model to determine total accident frequency (core damage frequency and containment release frequency); MACCS2 to convert release input to offsite property damage; and NUREG/BR-0184 methodology to convert offsite property damage to present worth dollars.

- Onsite exposure costs – Monetary value of dose to workers; use NUREG/BR-0184 best estimate occupational dose values for immediate and long-term dose, then apply NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

- Onsite economic costs – Monetary value of damage to onsite property; use NUREG/BR-0184 best estimate cleanup and decontamination costs, then apply NUREG/BR-0184 methodology to convert onsite property damage estimate to present worth dollars. It is assumed that, subsequent to a severe accident, the plant would not be restored to operation, therefore replacement/refurbishment costs are not included in onsite costs. Replacement power costs, unlikely to be incurred in a deregulated market, are also not included directly but are considered in the sensitivity analysis.

<u>SAMA Identification – Identify potential SAMAs from the following sources:</u>

- Severe Accident Mitigation Design Alternative analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants;

- NRC and industry documentation discussing potential plant improvements; and

- Documented insights provided by the ANO-1 staff.

<u>Preliminary Screening – Eliminate non-viable candidates, based upon:</u>

- SAMA improvements that modify features not applicable to ANO-1; or

- SAMA improvements that have already been implemented at ANO-1.

Final Screening of Remaining SAMAs – Using cost-benefit analysis, screen out SAMAs that do not provide an adequate level of benefit based on:

- Implementation of SAMA would require extensive plant reconstruction, or the cost of implementing SAMA would exceed the maximum possible benefit; or
  - Cost/Benefit Evaluation – Evaluate benefits and costs of implementing the SAMA:
    - Benefit calculation – Estimate benefits of implementing each SAMA individually;
    - Existing Level 2 modeling used.
    - SAMA impacts – Calculate impacts (i.e., onsite/offsite dose and damages) by manipulating the ANO-1 model to simulate revised plant risk following implementation of each individual SAMA.
    - Averted SAMA impacts – Calculate benefits for each SAMA in terms of averted consequences. Averted consequences are the arithmetic differences between the calculated impact for the base case and revised impact following implementation of each individual SAMA.
    - SAMA Benefits – Calculate total benefit for each SAMA.

  - Cost estimate – Estimate cost of implementing each evaluated SAMA. The detail of the cost estimate must be commensurate with the benefit; if a benefit is very low, it is not necessary to perform a detailed cost estimate to determine that the SAMA is not cost beneficial – expert judgement can be applied.

  - Sensitivity Analysis – Determine the effect that changing certain inputs, including averted onsite costs and discount rate, would have on the cost-benefit calculation.

  - Conclusions – Identify SAMAs that are cost beneficial, if any, and implementation plans or provide a basis for not implementing.

The Entergy Operations' SAMA analysis for ANO-1 is presented in the following sections. These sections provide a detailed discussion of the process presented above.

4.13.4.2 Establishing the Base Case

The purpose of establishing the base case is to provide the baseline for determining the risk reductions that would be attributable to the implementation of potential SAMAs. This severe accident risk, based on the ANO-1 PSA model, is calculated through use of the IPE Level 2 and the MACCS2 Level 3 model, based upon site-specific meteorology, population characteristics, and economic information.

The primary source of data relating to the base case is the ANO-1 PSA model. The ANO-1 model used is based upon the latest modeling information available for ANO-1, and uses PSA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;
- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The ANO-1 PSA model includes internal events (e.g., loss of feedwater event, loss of coolant accident) and is more advanced than the IPE. The ANO-1 PSA model is periodically updated as a result of:

- Equipment Performance – As data collection progresses, estimated failure rates and system unavailabilities change.
- Plant Configuration Changes – There is a time lag between changes to the plant and incorporation of those changes into the ANO-1 PSA model.
- Modeling Changes – The ANO-1 PSA model is refined to incorporate the latest state of knowledge.

The ANO-1 PSA model describes the results of the first two levels of the PSA for ANO-1. These levels are defined as follows: Level 1 determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and release of fission products to the environment.

Using the results of these analyses, the next step is to perform a Level 3 PSA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. MACCS2 is used for determining the offsite impacts for the Level 3 analysis, whereas the magnitude of the onsite impacts (in terms of clean up and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184. The principal phenomena analyzed are atmospheric transport of radionuclides, mitigative actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection, dose accumulation by a number of pathways, including food and water ingestion, and economic costs. Input for the Level 3 analysis includes the ANO-1 core radionuclide inventory, source terms from the IPE (as applied to the ANO-1 PSA model), site meteorological data, projected population distribution (within 50-mile radius) for the year 2025, emergency response evacuation modeling, and economic data.

The Level 3 analysis looks at the source term for each of 53 different release modes associated with endstates of the containment event tree. Because the analysis is based on probabilistic risk input, the analytical results relate the frequency of an impact to the magnitude of the impact (i.e., frequency versus risk). In general, severe accidents having the greatest predicted impact have the lowest predicted probability of occurrence. Attachment G contains detailed information on the SAMAs.

Offsite Exposure Costs

The Level 3 base case analysis shows an annual offsite exposure risk of 0.55 person-rem. This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem from NUREG/BR-0184. This monetary equivalent was then discounted to present value using the NRC's formula from NUREG/BR-0184:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE =	monetary value of accident risk avoided due to population doses, after discounting
R =	monetary equivalent of unit dose, ($2,000/person-rem)
F =	accident frequency (events/yr)
D_P =	population dose factor (person-rems/event)
S =	status quo (current conditions)
A =	after implementation of proposed action
r =	real discount rate = 7% (as a fraction, 0.07)
t_f =	years remaining until end of facility life = 20 years.

Using a 20-year period for remaining plant life and a 7% discount rate results in the monetary equivalent value of $11,908 and is presented in Table 4.13-1.

Offsite Economic Costs

The Level 3 analysis shows an annual offsite economic risk monetary equivalent of $956. Calculated values of offsite economic costs caused by severe accidents must also be discounted to present value. Discounting is performed in the same manner as for the public health risks in accordance with the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right) \frac{1 - e^{-rt_f}}{r}$$

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting

P_D = offsite property loss factor (dollars/event)

The resulting monetary equivalent of $10,290 is presented in Table 4.13-1.

<u>Onsite Exposure Cost</u>[8]

Values for occupational exposure associated with severe accidents are not derived from the ANO-1 PSA model, but, instead, are obtained from information published by the NRC in NUREG/BR-0184. The values for occupational exposure consist of "immediate dose" and "long-term dose." The best estimate value provided by the NRC for immediate occupational dose is 3,300 person-rem, and long-term occupational dose is 20,000 person-rem (over a ten-year clean-up period). The following equations are applied to these values to calculate monetary equivalents:

Immediate Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the immediate dose present value with the following equation:

Equation (1):

$$W_{IO} = \left(F_S D_{IO_S} - F_A D_{IO_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
IO = subscript denoting immediate occupational dose
R = monetary equivalent of unit dose, ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = years remaining until end of facility life.

The values used in the ANO-1 analysis are:

R = $2,000/person rem
r = 0.07
D_{IO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for t_f.

[8] Calculated values presented in this and subsequent subsections were calculated using a spreadsheet and may differ slightly from values calculated from the numbers provided; this is due to rounding performed on the numbers presented in this document.

For the basis discount rate, assuming F_A is zero, the bounding monetary value of the immediate dose associated with ANO-1's accident risk is:

$$W_{IO} = \left(F_S D_{IO_S}\right) R \frac{1 - e^{-rt_f}}{r}$$

$$= 3300 * F * \$2000 * \frac{1 - e^{-.07*20}}{.07}$$

For the core damage frequency for the base case, 1.03E-05/year,

$$W_{IO} = \$730$$

Long-Term Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the long-term dose present value with the following equation:

Equation (2):

$$W_{LTO} = \left(F_S D_{LTO_S} - F_A D_{LTO_A}\right) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm} \qquad (2)$$

where:

W_{LTO} =	monetary value of accident risk avoided long-term doses, after discounting, ($)
LTO =	subscript denoting long-term occupational dose
m =	years over which long-term doses accrue

The values used in the ANO-1 analysis are:

R =	$2,000/person rem
r =	.07
D_{LTO} =	20,000 person-rem /accident (best estimate)
m =	"as long as 10 years"

The license extension period of 20 years is used for t_f.

For the basis discount rate, assuming F_A is zero, the bounding monetary value of the long-term dose associated with ANO-1's accident risk is:

$$W_{LTO} = \left(F_S D_{LTO_S}\right) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm}$$

$$= \left(F_S \times 20000\right) \$2000 * \frac{1 - e^{-.07*20}}{.07} * \frac{1 - e^{-.07*10}}{.07 * 10}$$

For the core damage frequency for the base case, 1.03E-05/year,

$$W_{LTO} = \$3,181$$

Total Occupational Exposures

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related onsite (occupational) exposure avoided is:

$$AOE = \Delta W_{IO} + \Delta W_{LTO} \text{ (\$)}$$

where,

AOE= onsite exposure avoided

The bounding value for occupational exposure (AOE_B) is:

$$AOE_B = W_{IO} + W_{LTO} = \$730 + \$3181 = \$3911$$

The resulting monetary equivalent of $3,911 is presented in Table 4.13-1.

Onsite Economic Costs

Clean-up/Decontamination

The total cost of clean-up/decontamination of a power reactor facility subsequent to a severe accident is estimated in NUREG/BR-0184 at $1.5E+9; this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1-e^{-rm}}{r}\right)$$

where

PV_{CD} =	present value of the cost of cleanup/decontamination
CD =	subscript denoting clean-up/decontamination
C_{CD} =	total cost of the cleanup/decontamination effort, $1.5E+9
m =	cleanup period (10 years)
r =	discount rate (7%).

Therefore:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-.07*10}}{.07}\right)$$

where:

PV_{CD} =present value of the cost of clean-up/decontamination

$$PV_{CD} = \$1.079E+9$$

This cost is integrated over the term of the proposed license extension as follows:

$$U_{CD} = PV_{CD} \frac{1-e^{-rt_f}}{r}$$

where:

U_{CD} = total cost of clean-up/decontamination over the life of the plant

Based upon the values previously assumed:

$$U_{CD} = \$1.161E+10$$

Replacement Power Costs

With respect to replacement power, the rapid transition to energy deregulation makes it extremely remote and speculative that such costs would be incurred. If a nuclear plant were no longer able to sell its power in a deregulated market, one would expect the next marginal producer to replace the power at approximately the same market price. Given this expectation, consumers should not see any significant price impact, and consequently there should be no appreciable public or societal impact. Therefore, replacement power costs are not included in the onsite costs. However, a sensitivity analysis was performed that considered replacement power costs, modeled in accordance with the guidance provided in NUREG/BR-0184.

Repair and Refurbishment

It is assumed that the plant would not be repaired. However, a sensitivity analysis was performed that considered repair and refurbishment as a contributor to onsite averted costs. The model used for estimating this cost was that provided in NUREG/BR-0184 which is 20% of the long-term replacement power costs.

Total Onsite Property Damage Costs

The total averted onsite damage costs is, therefore:

$$AOSC = F * (U_{CD})$$

where:

F = Annual frequency of the event.
AOSC = averted onsite damage cost

For the core damage frequency for the base case, 1.03E-05/year,

$$AOSC = \$119,285$$

The resulting monetary equivalent of $119,285 is presented in Table 4.13-1.

4.13.4.3 SAMA Identification and Screening

The NRC and the nuclear industry have documented analyses of methods to mitigate severe accident impacts for existing and new plant's designs and for in-system evaluations. Attachment G.2 lists documents from which Entergy Operations gathered descriptions of candidate SAMAs. In addition, Entergy Operations, in preparing the ANO-1 IPE, gained insight into possible ANO-1 specific improvements that could reduce severe accident risks. Table G.2-1 of Attachment G.2 lists the 169 candidate SAMAs that Entergy Operations identified for analysis and identifies the source of the information. The first step in the analysis was to eliminate non-viable SAMAs through preliminary screening.

<u>Preliminary Screening</u>

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at ANO-1. Screening criteria include:

- Enhancements not applicable to ANO-1 (e.g., applicable only to boiling water reactors); and
- Enhancements that have already been implemented at ANO-1 (e.g., alternate diesel generator to cope with station blackout events).

Table G.2-1 of Attachment G.2 provides a brief discussion of each candidate SAMA and its disposition, whether eliminated from further consideration as not applicable, as already implemented, or designated for further analysis. Based on this preliminary screening, 80 candidate SAMAs were eliminated, and 89 of the original SAMAs were designated for further analysis.

<u>Final Screening/Cost-Benefit Analysis</u>

Entergy Operations estimated the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee's submittals, and site-specific cost estimates. Evaluation was performed based on a single nuclear unit implementation basis. The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

Screening based on level of benefit achieved was carried out in two steps. The first step involved calculating the maximum benefit that could possibly be provided by any one SAMA or combination of SAMAs. This maximum theoretical benefit is based upon the elimination of all plant risk and equates to the previously calculated base case risk. As shown in Table 4.13-1, the monetized value of this risk is approximately $145,000. Therefore, any SAMA having an estimated single nuclear unit cost of implementation exceeding this value would not be considered cost-beneficial and was screened from further consideration.

The next step involved performing a benefits analysis on the remaining SAMAs. The methodology for determining if a SAMA is beneficial consists of determining whether the benefit provided by implementation of the SAMA exceeds the expected cost of implementation. Since ANO-1 does not have an external events PSA model, the expected cost of each unscreened SAMA was compared with twice the calculated benefit of that SAMA. Since the benefits of the SAMAs were so small, engineering judgement was used as the basis for costs. The benefit is defined as the sum of the dollar equivalents for each severe accident impact (offsite exposure, offsite economic costs, occupational exposure, and onsite economic costs). In general, if the expected cost exceeded twice the calculated benefit, the SAMA was not considered cost-beneficial.

The result of implementation of each SAMA would be a change in the ANO-1 severe accident risk (i.e., a change in frequency or consequence of severe accidents). The methodology for calculating the magnitude of these changes is straightforward. First, the ANO-1 severe accident risk after implementation of each SAMA is calculated using the same methodology as for the base case. The results of the Level 2 model were combined with the Level 3 model to calculate these post-SAMA risks. The results of the benefit analyses for each of the SAMAs are presented in Table G.2-2 of Attachment G.2. Detailed cost estimations were not required due to the small base case result.

Each SAMA evaluation was performed in a bounding fashion. Bounding evaluations were performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. For example, one SAMA deals with installing digital large break LOCA protection; the bounding calculation to estimate the benefit of this improvement was total elimination of large breaks. Such a calculation obviously overestimates the benefit, but if the inflated benefit indicates that the SAMA is not cost-beneficial then the purpose of the analysis is satisfied.

Two types of evaluations were used in determining the benefit of the SAMAs, model requantification and importance measure analysis. Some of the SAMAs involve modification of system models; these SAMAs were evaluated by making relatively simple, bounding changes to one or more system models and quantifying the full model. This resulted in a new set of plant damage state frequencies which where analyzed to determine the impact on public risk.

An example of such an evaluation was the estimation of the benefit of less dependence of air compressors on offsite power (more diesel-driven power available for air compressors). This SAMA was evaluated in a bounding manner by modifying the fault trees such that the air compressors were not dependent on AC power; this results in an upper limit on the improvement that is possible through more reliable AC sources.

Other SAMAs were more quickly evaluated simply by examining (through importance measures) the contribution of specific components or human actions to the core damage frequency. For example, the SAMA associated with staggering the operation of high pressure injection pumps during a loss of service water event was examined in this manner. Loss of service water events contribute approximately 27% to the total core damage frequency at ANO-1. Through expert judgement it was estimated that the additional time for recovery of service water made available by staggering the operation of high pressure injection pumps would enhance the recovery potential only 10% to 20%. Based on this assessment, the benefit was estimated to be no greater than a 20% reduction in the loss of service water contribution to the total CDF.

For the cases in which the impact on risk was estimated through use of component or human action contribution to CDF, it was assumed that the benefit was proportional to the reduction in CDF. Use of this assumption is supported by the fact that the base case values for maximum attainable benefit is due primarily to onsite costs, which are proportional to CDF.

As described above for the base case, values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value. The formula for calculating net value for each SAMA is as follows:

Net value = ($APE + $AOC + $AOE + $AOSC) – COE

Where	$APE =	monetized value of averted public exposure ($)
	$AOC =	monetized value of averted offsite costs ($)
	$AOE =	monetized value of averted occupational exposure ($)
	$AOSC =	monetized value of averted onsite costs ($)
	COE =	cost of enhancement ($)

If the net value of a SAMA is negative, the cost of the enhancement is greater than the benefit and the SAMA is not cost beneficial. Because the total value for potential risk reduction at ANO-1 is small, Entergy Operations took the approach of comparing the expected cost of the SAMAs with twice the calculated benefit as a means of determining whether a more detailed cost analysis would be necessary. The expected cost of each SAMA (COE) was determined by either utilizing applicable cost estimates published in NRC submittals from other licenses or by expert judgement by knowledgeable ANO-1 staff.

The first step in the process was to review previous licensee SAMDA submittals (e.g., the Watts Bar Nuclear Plant SAMDA evaluation). If these previous submittals contained costs for a specific SAMDA, the SAMDA description was reviewed to determine if the cost estimate could reasonably be applied to ANO-1, based on ANO-1's design and licensing bases and knowledge of implementing plant modifications. If the previous licensee submittals did not contain cost estimates or if these cost estimates could not be applied to ANO-1, a review of the benefit was performed to determine whether the SAMA could be implemented for a cost equivalent to twice the benefit. Specific detailed cost estimates were not necessary to disposition the list of SAMAs. In addition, an expert panel review was performed to provide additional insights and opinion into the costs associated and benefits associated with some of the SAMAs that were clearly not cost beneficial. This expert panel also provided additional insights into the expected benefit from the SAMAs in relation to other parameters (i.e., external events, current procedures, training, etc.). The cost-benefit comparison and disposition of each remaining SAMA are presented in Table G.2-2 of Attachment G.2.

4.13.4.4 Sensitivity Analyses

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.13.4.2 used the 7% discount rate in calculating benefits of all the unscreened SAMAs. Entergy Operations also performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs.

Other sensitivities were performed; each of the sensitivities resulted in an additional benefit result for each of the SAMAs analyzed in the cost-benefit analysis. In addition to the discount rate sensitivity discussed above, the sensitivities performed include:

- Calculation of the benefit assuming the baseline discount rate and assuming external events contributed an amount equivalent to internal events to the CDF.
- Calculation of the benefit assuming averted onsite costs included the cost of replacement power and assuming the baseline discount rate.
- Calculation of the benefit assuming averted onsite costs included the cost of repair/refurbishment and assuming the baseline discount rate.
- Calculation of the benefit assuming a discount rate that is realistic for Entergy Operations (15%).

The benefits calculated for each of these sensitivities are presented in Attachment G Table G.2-3.

4.13.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations analyzed 169 conceptual alternatives for mitigating ANO-1 severe accident impacts. Preliminary screening eliminated 80 SAMAs from further consideration, based on inapplicability to ANO-1's design or features that have already been incorporated into ANO-1's current design and/or procedures and programs. During the final disposition, 88 remaining SAMA candidates were eliminated because the cost was expected to exceed twice their benefit or because of disproportionately high implementation costs. The remaining SAMA candidate (#129, "*Emphasize timely recirc swapover in operator training*") was found to be potentially cost beneficial. Training issues are considered to be not relevant to the license renewal process, since training is not an age-related issue. Using the 7% real discount rate recommended by NUREG/BR-0184, 88 SAMA candidates for which the evaluation has been completed were determined not to be cost-beneficial. The sensitivities performed for each of the SAMAs indicated that the results of the analysis would not change for the conditions analyzed. In summary, based on the results of this SAMA analysis, Entergy Operations discovered only one marginally cost-beneficial SAMA which is not age-related.

Table 4.13-1 Estimated Present Dollar Value Equivalent for Severe Accident at ANO-1

Parameter	Present Dollar Value ($)
Offsite population dose	$11,908
Offsite economic costs	$10,290
Onsite dose	$3,911
Onsite economic costs	$119,285
Total	$145,394

4.14 Transportation of High-Level Waste

4.14.1 Finding from 10CFR 51, Appendix B to Subpart A, Table B-1

"The impacts of transporting spent fuel enriched up to 5% uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU and the cumulative impacts of transporting high-level waste to a single repository, such as Yucca Mountain, Nevada are found to be consistent with the impact values contained in 10CFR51.52(c), Summary Table S-4 – Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Power Reactor. If fuel enrichment or burnup conditions are not met, the applicant must submit an assessment of the implications for the environmental impact values reported in 10CFR51.52."

4.14.2 Entergy Operations' Response

The NRC issued a final rule on September 3, 1999 (became effective October 4, 1999) amending 10CFR Part 51 that changed the transportation of high-level waste from a Category 2 to a Category 1 issue [Reference 34]. As a result of this Category 1 finding, license renewal applicants are not required to prepare a separate analysis of this issue as long as no new and significant information exists. The analysis in NUREG-1437, Volume 1, Addendum 1 [Reference 35] forms the technical basis for this rulemaking.

Entergy Operations is not aware of new and significant information regarding the transportation of high-level waste that would make the generic Category 1 conclusion codified by the NRC not applicable for ANO-1. In addition, ANO-1 meets the NRC criteria for fuel enrichment and burnup conditions. Therefore, an assessment of the implications for the environmental impact values reported in 10CFR51.52 need not be submitted.

4.15 Irreversible or Irretrievable Resource Commitments

4.15.1 Requirement [10CFR51.45(b)(5)]

The applicant's report shall discuss any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

4.15.2 Entergy Operations' Response

The February 1973 Final Environmental Statement [Reference 1], prepared in connection with the issuance of the original operating license for ANO-1, evaluated the commitment of resources associated with the construction and operation of ANO-1. These materials include:

- Nuclear fuel which is spent and converted into waste radioactive material;
- Materials used in the normal maintenance of the plant;
- Elemental materials, including iron, zirconium, and aluminum, which become, either by themselves or in combinations with other materials, radioactive.

The continued operation of ANO-1 during the extended license term will result in resource commitments. These resources include materials and equipment required for plant maintenance and operation, the nuclear fuel utilized by the reactor, and ultimately, permanent onsite storage space for the spent fuel assemblies. However, the likely power generation alternatives in the event ANO-1 ceases operation on or before the expiration of the current operating license will require commitment of resources for construction of the replacement plants as well as fuel to operate the plants.

4.16 Short-Term Use Versus Long-Term Productivity

4.16.1 Requirement [10CFR51.45(b)(4)]

The applicant's report shall discuss the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.

4.16.2 Entergy Operations' Response

The FES [Reference 1], prepared for the issuance of the original operating license for ANO-1, evaluated the balance between the short-term uses of the environment and the maintenance and enhancement of the long-term productivity associated with the construction and operation of ANO-1. This balance is now well established. Renewal of the ANO-1 Operating License and continued operation of the plant will not alter the existing balance, but it may postpone the availability of the site for other uses. Denial of the application to renew the operating license will lead to permanent shutdown of the plant and will alter the balance in a manner that depends on subsequent uses of the site.

4.17 Unavoidable Adverse Impacts

4.17.1 Requirement [10CFR51.45(b)(2)]

The applicant's report shall discuss any adverse environmental effects that cannot be avoided upon implementation of the proposed project.

4.17.2 Entergy Operations' Response

Sections 4.2 through 4.13 of this report contain the results of Entergy Operations' review and the analyses of the 12 specific analytical requirements, as required by 10CFR51.53(c)(3)(ii). These reviews take into account the information that has been provided in the GEIS, Appendix B to Subpart A of Part 51, and information specific to ANO-1.

This review and analysis did not identify any significant adverse environmental impacts associated with the continued operation of ANO-1. The evaluation of structures and components as required by 10CFR54.21 has been completed. No plant refurbishment activities, outside the bounds of normal plant component replacement and inspections, have been identified as necessary to support continued operation of ANO-1 beyond the end of the existing operating license. As a result of these reviews and analyses, Entergy Operations is not aware of any significant adverse environmental effects that cannot be avoided upon implementation of the proposed project.

4.18 Environmental Justice

4.18.1 Findings from 10CFR51, Appendix B to Subpart A, Table B-1

"The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews."

4.18.2 Background

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations" 59 FR 7629 (Feb. 11, 1994), requires Federal agencies to identify and address, as appropriate, "disproportionately high and adverse human health or environmental effects" from their programs, policies, and activities on minority and low-income populations. Former NRC Chairman Selin took the position that the NRC, although an independent agency, would comply with this Executive Order and would participate with an Interagency Working Group to develop implementation guidelines. The environmental justice review was performed in accordance with Attachment 4 of "NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues", dated September 21, 1999 [Reference 36].

4.18.3 Environmental Impacts from the Proposed Action

As noted above, the consideration of environmental justice is required to assure that federal programs and activities will not have "disproportionately high and adverse human health or environmental effects...on minority populations and low-income populations..." Entergy Operations' analyses of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii) determined that the impacts from the continued operation of ANO-1 through the renewal period were insignificant. As indicated in the NRR Procedure for Environmental Justice Reviews [Reference 36], if no significant offsite impacts will occur, there can be no disproportionately high and adverse impacts on any member of the public, including minority and low-income populations. Based on the review of these issues as discussed in Sections 4.2 through 4.13, no review for environmental justice is necessary. However, the following information is presented to assist the NRC's review of this issue.

4.18.4 Description of Process used in Entergy Operations' Review-NRR Procedure for Environmental Justice Reviews

The NRR Procedure for Environmental Justice Reviews [Reference 36] was developed to provide guidance to the NRC Office of Nuclear Reactor Regulation staff on conducting environmental justice reviews. The criteria in this reference were used to determine if there was a sufficiently large enough minority or low-income population composition in the vicinity of ANO to warrant an environmental justice review. This reference requires the staff to:

1. Determine whether the regulatory action will be supported by an EIS or by an EA. When the regulatory action requires the preparation of an EIS or a supplement to an EIS, an environmental justice review must be prepared using the process discussed in paragraphs 2 through 9 below. Under most circumstances, no environmental justice review should be conducted where an EA is prepared. If it is determined that a particular action will have no significant environmental impact, then there is no need to consider whether the action will have disproportionately high adverse impacts on certain populations.

2. During the public scoping process for the EIS, include environmental justice as a discussion topic along with other topics normally addressed in the EIS scoping process. Solicit input from populations potentially affected by the action.

3. Identify the environmental impact site(s) using input from the public scoping process and the evaluation of environmental impacts for the EIS. Determine the location of environmental impact sites for all adverse human health or environmental impacts which are known to be significant or perceived as significant by groups and/or individuals (typically up to 80 kilometers or 50 miles). The size of the impact sites will vary depending upon the nature of the impacts, and should be consistent with the areas used to review environmental impacts in the EIS.

4. Determine the geographic area to be used for the comparative analysis of minority or low-income populations. The geographic area is a larger area that encompasses all the environmental impact sites (for example, a county or group of counties).

5. Determine the minority and low-income composition within a geographic area. Determine the percentage of the total population within the geographic area for each minority and low-income category. Minority is defined as Black; American Indian, Eskimo, or Aleut; Asian or Pacific Islander; other non-white; and Hispanic origin.[9] The low-income composition is determined by using the percentage of households within the geographic area that are below the poverty level. For performing environmental justice reviews, low-income is defined as being below the poverty level as defined by the Census Bureau.

6. For each environmental impact site, determine the percentage of the minority and low-income population.

[9] Note that the values for the Hispanic populations may also be included in the values for the white, black, or minority populations.

7. An environmental justice review must be performed if one of the following exists:

   a) A minority population exists if 1) the minority population of the environmental impact site exceeds 50%, or 2) the minority population percentage of the environmental impact site is significantly greater (typically 20%) than the minority population percentage in the geographic area chosen for the comparative analysis.

   b) A low-income population is considered to be present if the percentage of households below the poverty level in an environmental impact site is significantly greater (typically at least 20%) than the low-income population percentage in the geographic area chosen for the comparative analysis.

8. When minority or low-income populations exist, it must be determined if disproportionately high and adverse effects result from the proposed action.

9. Conclusions regarding whether the proposed action will have disproportionately high and adverse environmental impacts on minority or low-income populations should be clearly stated and supported with sufficient information.

4.18.5 Environmental Impact Site

As outlined in the NRR Procedure, environmental impact sites must be designated for all adverse human or environmental impacts arising from the proposed action which are known to be significant. As illustrated by the results of Entergy Operations' review of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii), there are no significant adverse human or environmental impacts arising from the renewal of ANO-1's operating license. Likewise, the Category 1 issues are insignificant. Accordingly, no environmental impact sites need to be designated for the purposes of an environmental justice review at ANO-1. However, to assist the NRC Staff in its review of this issue, Entergy Operations performed a review of minority and low-income population data for the ANO vicinity. Population information is shown below for a hypothetical environmental impact site defined as an area within a 10-mile (16.1 km) radius of ANO. This area was selected to be consistent with the area used for the Emergency Planning Zone at ANO.

Additional information is also provided for minority and low-income populations using a 50-mile radius environmental impact site. This area was selected as an alternative environmental impact site and coincides with the area used for the SAMA analysis [ER Section 4.13]. The population data provided for a 50-mile radius environmental impact site is less detailed than information outlined for a 10-mile radius environmental impact site. It is, however, sufficient to satisfy the objectives of the NRR Procedure for Environmental Justice Reviews.

4.18.6 Selection of Geographic Area

To determine if a minority or low-income population exists within the environmental impact site, population data within a larger area was obtained for a comparative analysis. ANO is located in the southwestern portion of Pope County near the boundaries of Johnson, Logan, and Yell Counties [Figure 4.18-1]. The geographic area for the analysis was selected to be the area composed of portions of the four counties within a 15-mile (24.2 km) radius from ANO. Comparison of the data for minority populations and low-income populations shows that the data for the 15-mile (24.2 km) radius for minority populations and for low-income households are representative of populations residing within Pope, Johnson, Logan, and Yell Counties (Tables 4.18-1 through 4.18-5).

An additional analysis of minority and low-income populations was performed using the State of Arkansas as a geographic area. Minority and low-income population data is provided for a comparative analysis with population data within the 50-mile radius environmental impact site. Again, state-wide data presented below is less detailed than information outlined for the 15-mile radius geographic area, but it is sufficient to satisfy the objectives of the NRR Procedure for Environmental Justice Reviews. The population data was based on the 1990 US Census and was obtained from the Census State Data Center/GIS Laboratory, Institute for Economic Advancement, University of Arkansas at Little Rock [Reference 37].

4.18.7 Method to Determine Block Groups within 10 and 15-Mile Radius

The U.S. Census Bureau 1990 decennial census database is the most recent source for population data at the block group level. This source of data includes the geo-referenced location for the center (or centroid) for each block group. Block groups with area centroids within the 10, 15, and 50-mile radii used in this environmental justice review were identified using ARCVIEW™ Geographic Information System software. ARCVIEW GIS was also used to extract and compile the minority and low-income population data from U.S. Census Bureau database. The information for these block groups was then reviewed with respect to the NRR criteria for minority and low-income populations.

4.18.8 Comparison of 1990 U.S. Census Data to More Recent Data

The 1990 decennial census is the most current data available for minority and low-income populations at the block group level. There is no estimated 1997 block group data available for minority and low-income populations. A comparison was performed of the minority population percentages at the block group level in the 1990 census to the 1997 census estimates of minority population percentages at the county level. As shown in Table 4.18-1, there is no significant difference between the 1990 census data and the 1997 census estimates for minority populations. No 1997 estimates of low-income populations are available at the county level. The 1990 census data also provides the most current data source for this segment of the population.

4.18.9 Minority Population Review

As noted above, two hypothetical environmental impact sites (10-mile radius and 50-mile radius) and two geographic areas (15-mile radius and the State of Arkansas) were selected for comparative analysis. Discussed below are the results of these two reviews, which indicate the minority population in the vicinity of ANO is relatively low and no environmental justice review is required.

Population data within a 10-mile environmental impact site was reviewed for any significant minority populations. Even at the block group level, census data showed low percentages of minority populations. One block group, within the municipality of Russellville located in Pope County [Figures 4.18-2 and 4.18-3], was identified which had a significant minority population (significant minority population is considered to be one that exceeded the percentage of minority population for the 15-mile radius geographic area by 20% or more). Table 4.18-3 provides the percentages of minority populations for the individual block groups within the 10-mile radius environmental impact site.

The minority population percentage within the 10-mile (16.1 km) radius environmental impact site is 5.0% and within the 15-mile geographic area is 4.1% (Table 4.18-2). Therefore, a minority population, for the purposes of an environmental justice review, does not exist because the percentage of minority population within the 10-mile (16.1 km) radius (5.0%) does not exceed the percentage of minority within the total population of the geographic area (4.1%) by 20% or more, and the percentage of minority population within the 10-mile (16.1 km) radius (5.0%) does not exceed 50%.

A minority population does not exist when a larger environmental impact site and geographic area are considered. Within a 50-mile radius of ANO, the minority population (12,207) composes 5.8% of the total population (210,198). The minority population of Arkansas (406,332) composes 17.3% of the total population in Arkansas (2,350,725). These census data do not meet the NRR criteria which would indicate a minority population exists within the 50-mile radius environmental impact site.

4.18.10 Low-Income Population Review

Two hypothetical environmental impact sites (10-mile radius and 50-mile radius) and two geographic areas (15-mile radius and the State of Arkansas) were selected for comparative analysis of low-income population data. As shown below, the percentage of low-income population in the vicinity of ANO is relatively low and no environmental justice review is required.

Table 4.18-4 compares the percentage of low-income households within the 10-mile (16.1 km) radius environmental impact site and the 15-mile (24.2 km) radius geographic area with the percentage of low-income households of Johnson County, Logan County, Pope County, and Yell County, and the State of Arkansas. No significant difference exists in the percentage of low-income populations within the total population of the 10-mile and 15-mile radii, county, or state-wide areas.

Population data within a 10-mile (16.1 km) radius environmental impact site was reviewed for significant low-income populations (households) near ANO (significant low-income population was considered to be one that exceeded the percentage of low-income population for the 15-mile geographic area by 20% or more). At the block group level, census data showed low-income populations percentages ranged from 0.0% to 43.4% (Table 4.18-5). Two block groups within the municipality of Russellville located in Pope County were identified with significant low-income populations [Figure 4.18-4 and Figure 4.18-5]. No environmental impacts were identified by which these low-income populations would be disproportionately and adversely affected by the renewal of the ANO-1 license.

The total low-income population percentage within the 10-mile (16.1 km) radius environmental impact site is 16.4% and within the 15-mile (24.2 km) radius geographic area is 16.9% (Table 4.18-4). A low-income population, for the purpose of an environmental justice review, does not exist because the low-income population of the environmental impact site does not exceed the low-income population of the geographic area by 20% or more.

A low-income population does not exist when a larger environmental impact site (50-mile radius) and geographic area (State of Arkansas) is considered. Within a 50-mile radius of ANO, the low-income population (14,922) composes 7.1% of the total population (210,198). The low-income population for Arkansas (174,877) composes 7.4% of the total population in the state (2,350,725). These 1990 census data show the low-income population within a 50-mile radius of ANO is insignificant and does not meet the NRR criteria required for an environmental justice review.

4.18.11 Conclusion

As part of its environmental assessment of this proposed action, Entergy Operations has determined that no significant off-site impacts will be created by the renewal of the ANO-1 license. This conclusion is supported by the review performed of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii). As the NRR Procedure for Environmental Justice Reviews recognizes, if no significant off-site impacts occur in connection with the proposed action, then no member of the public will be substantially affected. Therefore, there can be no disproportionately high and/or adverse impacts or effects on any member of the public, including minority and low-income populations, resulting from the renewal of the ANO-1 license. In such instances, the NRC does not require an environmental justice review to be performed.

Entergy Operations has also reviewed the minority and low-income populations within the environmental impact sites of 10-mile and 50-mile radii of ANO to assist the NRC in its review of the environmental justice issue. The results of the review showed that environmental justice concerns related to the proposed action (license renewal) are insignificant. No additional review is required for the proposed action at ANO-1 because the population demographics within the project area do not meet the specified criteria requiring an environmental justice review. The population near ANO does not meet these criteria because:

- the percentages of minority citizens in the two environmental impact sites do not exceed by more than 20% the percentages of the minority population within the two geographic areas ;

- the percentages of minority citizens in the environmental impact sites do not exceed 50%; and

- the percentages of the low-income population in the environmental impact sites do not exceed by more than 20% the percentages of the low-income population in the geographic areas.

Additionally, the review of environmental justice issues did not identify any minority or low-income populations having special vulnerabilities due to customs, activities, location, or dependence on particular resources that would be disproportionately and adversely affected by the renewal of the ANO-1 license.

Table 4.18-1, Comparison of Minority Data – 1990 Census Data to 1997 Estimates for Pope, Johnson, Logan, and Yell Counties

County	Total Persons	Percent White	Percent Black	Percent American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
Johnson County (1990)	18,221	96.8	1.7	0.6	0.4	0.5	1.2
Johnson County (1997)	21,165	97.0	1.9	0.6	0.6	N/A	2.3
Logan County (1990)	20,557	97.7	1.3	0.6	0.1	0.2	0.7
Logan County (1997)	21,245	97.6	1.6	0.6	0.2	N/A	1.4
Pope County (1990)	45,883	96.2	2.5	0.7	0.4	0.2	0.9
Pope County (1997)	51,219	95.9	2.8	0.7	0.6	N/A	2.0
Yell County (1990)	17,759	96.7	2.1	0.4	0.6	0.2	1.0
Yell County (1997)	19,089	96.0	2.8	0.5	0.7	N/A	2.1

1990 data from 1990 U.S. Census Bureau C90STF1A Database
1997 data from U.S. Census Bureau Estimates of Population of Counties by Race and Hispanic Origin: September 4, 1998

Table 4.18-2, Comparison of Minority Population Percentage – 10-Mile Radius Versus 15-Mile Radius

Area	Total Persons	Percent White	Percent Total Minority	Percent Black	Percent American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
Within 10 Mile (16.1km) Radius [a]	35,820	95.0	5.0	3.6	0.7	0.4	0.3	0.9
Within 15 Mile (24.2km) Radius [a]	49,692	95.9	4.1	2.7	0.7	0.4	0.3	0.8
Johnson County [b]	18,221	96.8	3.2	1.7	0.6	0.4	0.5	1.2
Logan County [b]	20,557	97.7	2.3	1.3	0.6	0.1	0.2	0.7
Pope County [b]	45,883	96.2	3.8	2.5	0.7	0.4	0.2	0.9
Yell County [b]	17,759	96.7	3.3	2.1	0.4	0.6	0.2	1.0
Johnson, Logan, Pope, & Yell Counties	102,420	96.7	3.3	2.0	0.6	0.4	0.3	0.9
Arkansas [b]	2,350,725	82.8	17.2	15.9	0.5	0.5	0.3	0.8

[a] Source of Data: U.S. Census Bureau 1990 C90STF3A Data
[b] Source of Data: U.S. Census Bureau 1990 C90STF1A Data
Note: Table 4.18-3 provides data on the percentage of minorities in the individual block groups, within the 10-mile (16.1 km) radius

Table 4.18-3, Percent of Minority Population – Block Groups within 10-Mile Radius

Block Group	County	Block Group Total Persons	Percent White	Percent Black	%American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
050719522.00:2	Johnson	379	96.3	0.0	1.6	1.8	0.3	0.3
050719522.00:3	Johnson	359	98.3	0.0	1.4	0.3	0.0	1.4
050839501.00:1	Logan	755	100.0	0.0	0.0	0.0	0.0	0.0
051159507.00:3	Pope	8	100.0	0.0	0.0	0.0	0.0	0.0
051159508.00:1	Pope	1,360	98.8	0.2	1.0	0.0	0.0	1.0
051159508.00:2	Pope	1,425	98.4	0.0	0.8	0.5	0.3	0.6
051159509.00:1	Pope	121	99.2	0.0	0.8	0.0	0.0	0.8
051159509.00:2	Pope	737	96.9	0.0	3.1	0.0	0.0	0.0
051159509.00:3	Pope	481	99.8	0.0	0.2	0.0	0.0	0.0
051159509.00:4	Pope	1,484	99.7	0.0	0.0	0.3	0.0	0.3
051159512.00:1	Pope	605	98.5	0.0	0.0	1.5	0.0	0.7
051159512.00:2	Pope	250	99.2	0.0	0.0	0.0	0.8	1.2
051159512.00:3	Pope	64	96.8	1.6	1.6	0.0	0.0	1.6
051159513.00:1	Pope	1,428	99.4	0.6	0.0	0.0	0.0	0.0
051159513.00:2	Pope	1,659	94.3	4.5	0.7	0.5	0.0	0.7
051159513.00:3	Pope	613	97.2	2.0	0.0	0.0	0.8	4.4
051159513.00:4	Pope	686	97.4	1.7	0.9	0.0	0.0	0.0
051159513.00:5	Pope	1,153	93.4	0.7	1.3	3.9	0.7	3.3
051159514.00:1	Pope	586	93.7	6.3	0.0	0.0	0.0	0.0
051159514.00:2	Pope	1,448	89.9	5.6	1.7	0.0	2.8	5.2
051159514.00:3	Pope	362	86.2	9.9	3.9	0.0	0.0	0.0
051159514.00:4	Pope	1,322	96.0	4.0	0.0	0.0	0.0	0.8
051159514.00:5	Pope	291	77.3	15.5	7.2	0.0	0.0	0.0
051159515.00:1	Pope	1,755	96.1	2.3	0.1	1.5	0.0	0.0
051159515.00:2	Pope	3,003	93.5	5.8	0.5	0.2	0.0	0.3
051159515.00:3	Pope	880	97.3	0.0	1.7	0.0	1.0	4.2
051159515.00:4	Pope	577	71.4	28.6	0.0	0.0	0.0	0.0
051159515.00:5	Pope	1,131	95.8	4.2	0.0	0.0	0.0	0.0
051159515.00:6	Pope	888	94.6	2.8	0.0	2.6	0.0	0.0
051159516.00:1	Pope	471	97.9	0.0	2.1	0.0	0.0	0.0
051159516.00:2	Pope	759	97.9	1.6	0.0	0.0	0.5	0.5
051159516.00:3	Pope	836	97.5	2.5	0.0	0.0	0.0	0.0
051159516.00:4	Pope	1,893	90.3	7.7	0.7	0.3	1.0	0.8
051159516.00:5	Pope	397	100.0	0.0	0.0	0.0	0.0	0.0
051159516.00:6	Pope	412	95.6	2.9	1.5	0.0	0.0	3.9
051499523.00:1	Yell	497	100.0	0.0	0.0	0.0	0.0	0.0
051499523.00:2	Yell	1,095	100.0	0.0	0.0	0.0	0.0	0.0
051499523.00:3	Yell	213	97.2	0.0	2.8	0.0	0.0	0.0
051499523.00:4	Yell	1,366	80.3	19.3	0.0	0.0	0.4	0.4
051499523.00:5	Yell	452	96.2	0.0	0.0	2.4	1.3	2.0
051499524.00:1	Yell	1,096	99.4	0.0	0.6	0.0	0.0	1.3
051499524.00:2	Yell	519	95.9	0.0	3.1	1.0	0.0	0.0
051499524.00:5	Yell	6	100.0	0.0	0.0	0.0	0.0	0.0

Source of Data: U.S. Census Bureau 1990 C90STF3A Data

Table 4.18-4, Comparison of Households Below Poverty Level Percentage – 10-Mile Radius Versus 15-Mile Radius

Area	Total Number of households	Number of households below poverty	Percent of households below poverty
Within 10 Mile (16.1km) Radius [(a)]	13,482	2,211	16.4
Within 15 Mile (24.2km) Radius [(a)]	18,460	3,124	16.9
Johnson County [(b)]	6,999	1,475	21.1
Logan County [(b)]	7,665	1,610	21.0
Pope County [(b)]	16,689	2,856	17.1
Yell County [(b)]	6,941	1,351	19.5
Johnson, Logan, Pope, & Yell Counties	38,294	7,292	19.0
Arkansas [(b)]	891,665	174,877	19.6

[(a)] Source of Data U.S. Census Bureau 1990 C90STF3A Data

[(b)] Table 4.18-5 provides data on the percentage of low-income households in the individual block groups within the 10 mile (16.1 km) radius.

Table 4.18-5, Percentage of Households Below Poverty Level – Block Groups within 10-Mile Radius of ANO

Block Group	County	Block Group Total Number of Households	Number of Households Below Poverty	Percent of Households Below Poverty
050719522.00:2	Johnson	147	23	15.6
050719522.00:3	Johnson	123	26	21.1
050839501.00:1	Logan	308	68	22.1
051159507.00:3	Pope	3	1	33.3
051159508.00:1	Pope	437	52	11.9
051159508.00:2	Pope	553	69	12.5
051159509.00:1	Pope	44	8	18.2
051159509.00:2	Pope	294	74	25.2
051159509.00:3	Pope	172	33	19.2
051159509.00:4	Pope	526	85	16.2
051159512.00:1	Pope	208	20	9.6
051159512.00:2	Pope	91	15	16.5
051159512.00:3	Pope	22	3	13.6
051159513.00:1	Pope	480	24	5.0
051159513.00:2	Pope	630	107	17.0
051159513.00:3	Pope	281	66	23.5
051159513.00:4	Pope	305	105	34.4
051159513.00:5	Pope	558	111	19.9
051159514.00:1	Pope	301	79	26.2
051159514.00:2	Pope	76	33	43.4
051159514.00:3	Pope	135	22	16.3
051159514.00:4	Pope	536	106	19.8
051159514.00:5	Pope	126	20	15.9
051159515.00:1	Pope	628	27	4.3
051159515.00:2	Pope	1032	74	7.2
051159515.00:3	Pope	349	16	4.6
051159515.00:4	Pope	229	95	41.5
051159515.00:5	Pope	482	47	9.8
051159515.00:6	Pope	304	13	4.3
051159516.00:1	Pope	261	26	10.0
051159516.00:2	Pope	407	55	13.5
051159516.00:3	Pope	295	34	11.5
051159516.00:4	Pope	720	224	31.1
051159516.00:5	Pope	145	23	15.9
051159516.00:6	Pope	130	14	10.8
051499523.00:1	Yell	219	39	17.8
051499523.00:2	Yell	507	68	13.4
051499523.00:3	Yell	70	11	15.7
051499523.00:4	Yell	574	145	25.3
051499523.00:5	Yell	182	46	25.3
051499524.00:1	Yell	390	80	20.5
051499524.00:2	Yell	201	23	11.4
051499524.00:5	Yell	2	0	0.0

Source of Data: U.S. Census Bureau 1990 C90STF3A Data

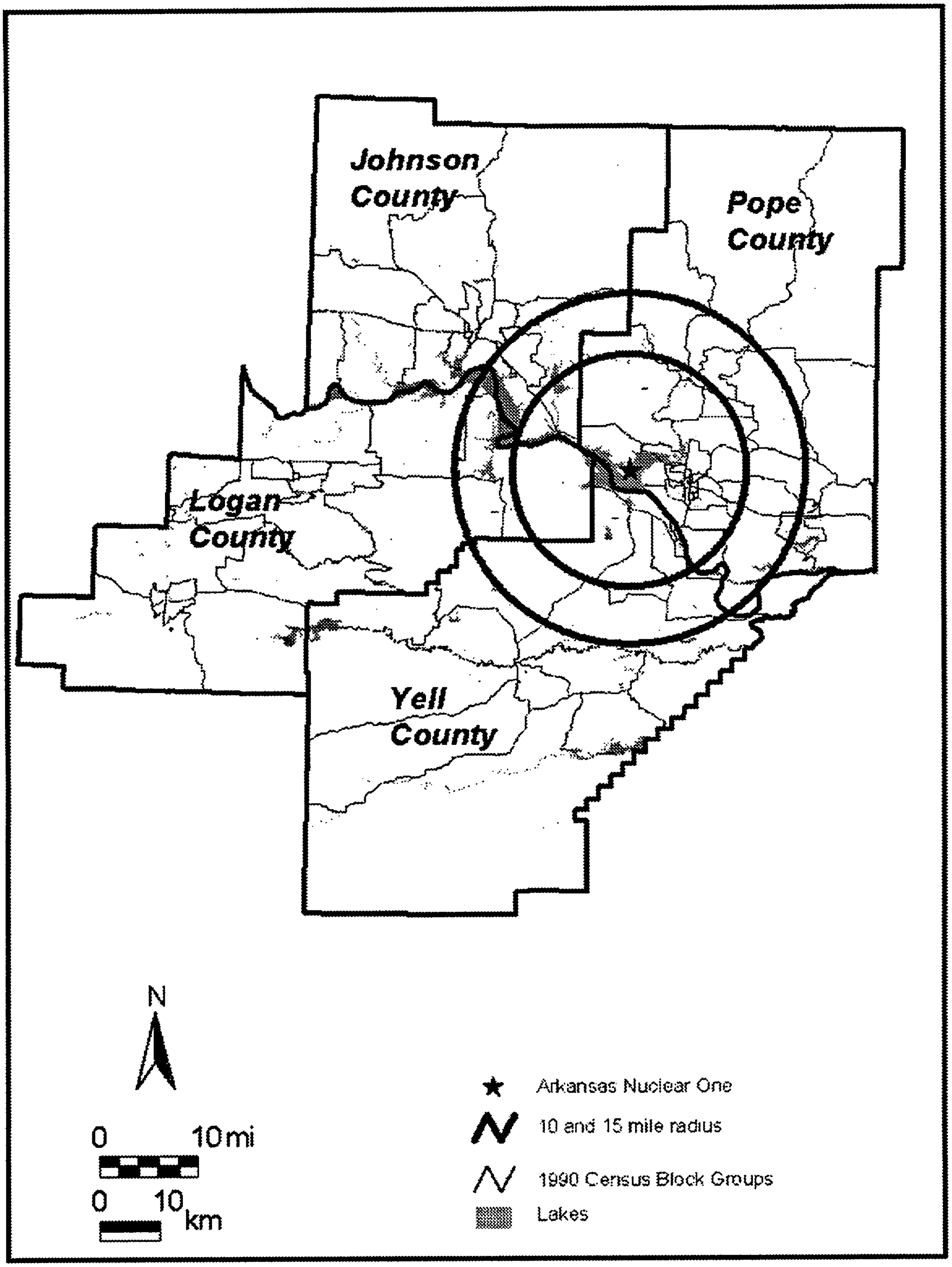

Figure 4.18-1, Census Block Groups – 10-Mile and 15-Mile Radius

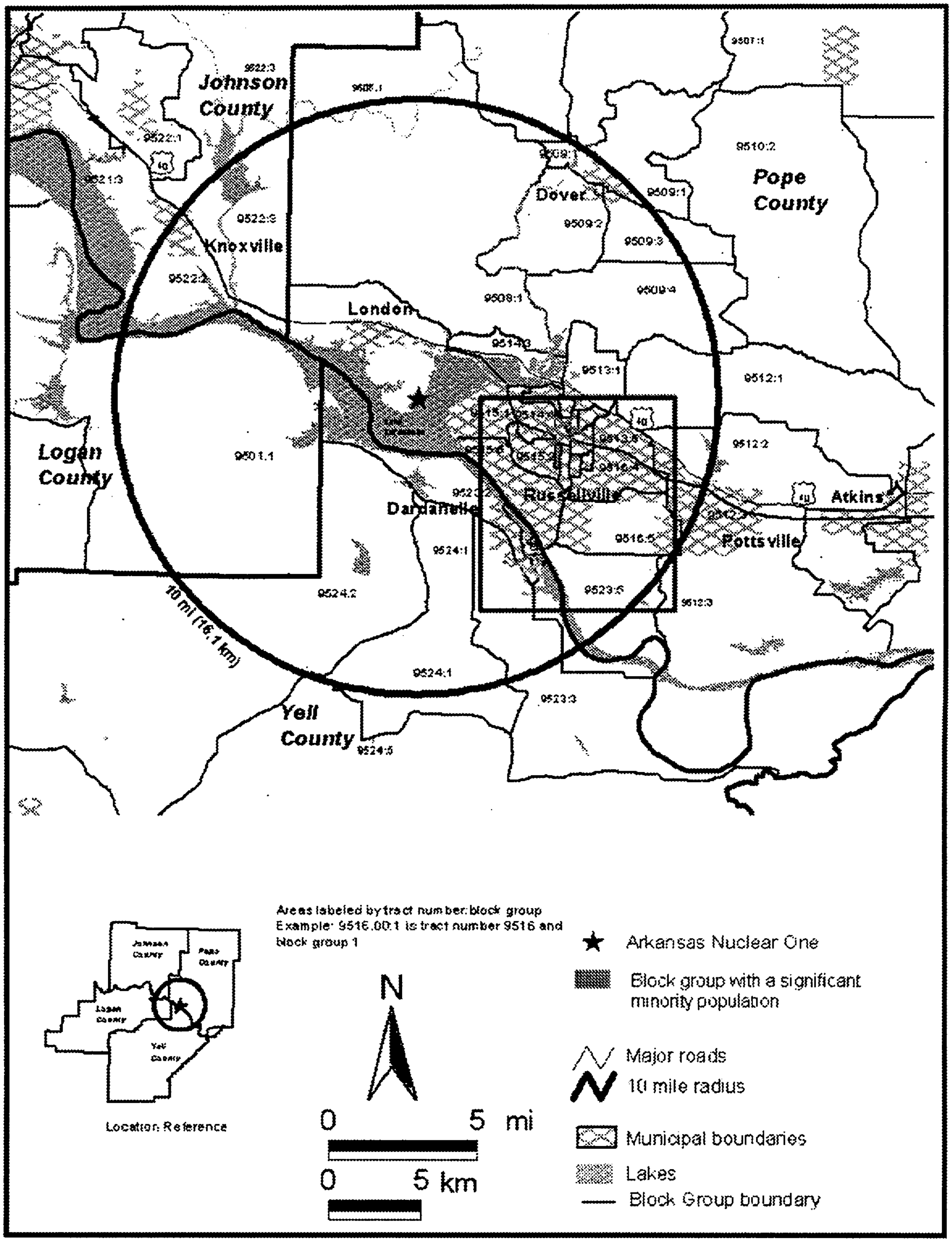

Figure 4.18-2, Block Groups – Minority Population Review

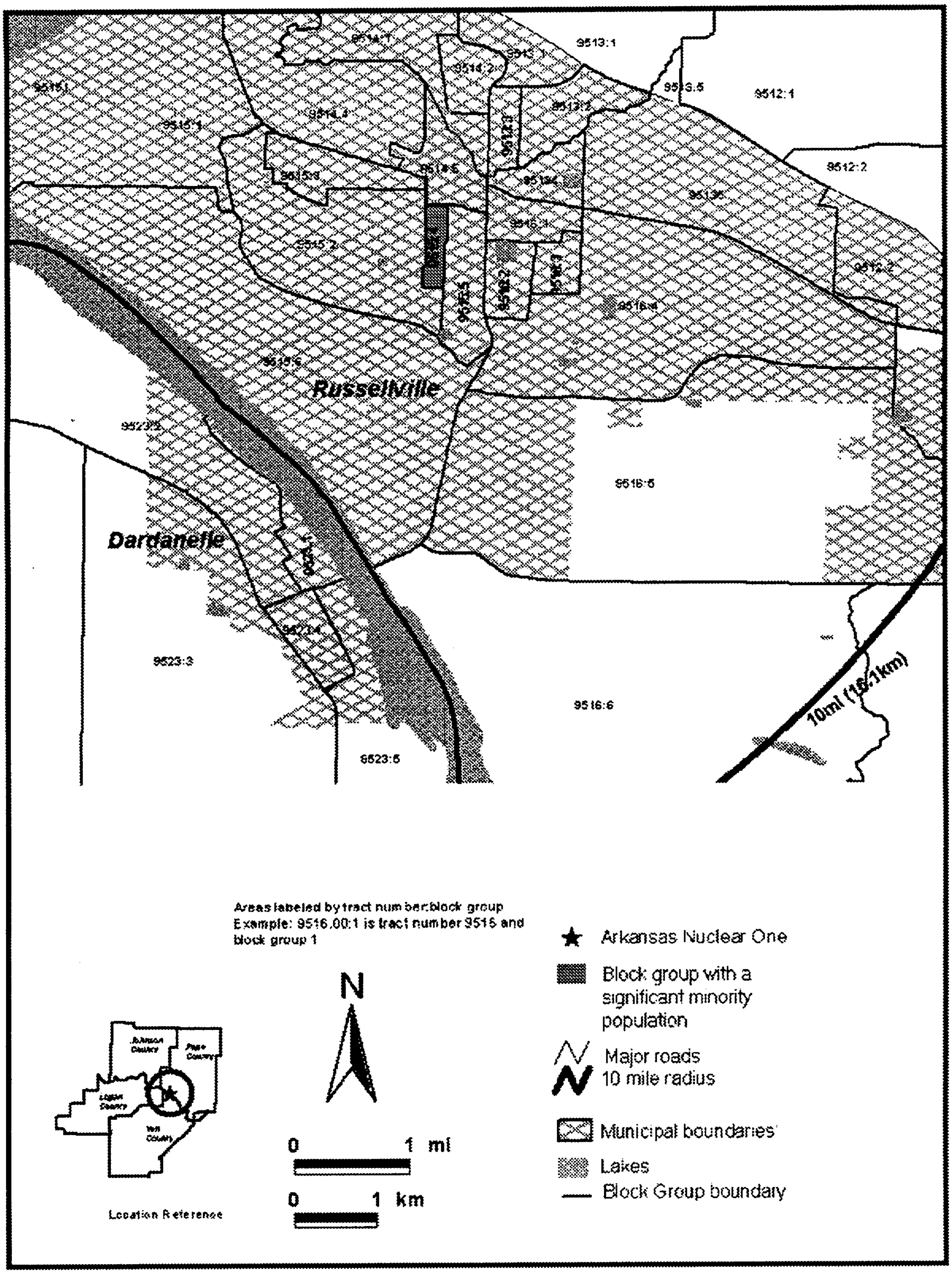

Figure 4.18-3, Census Block Groups – Minority Population Review

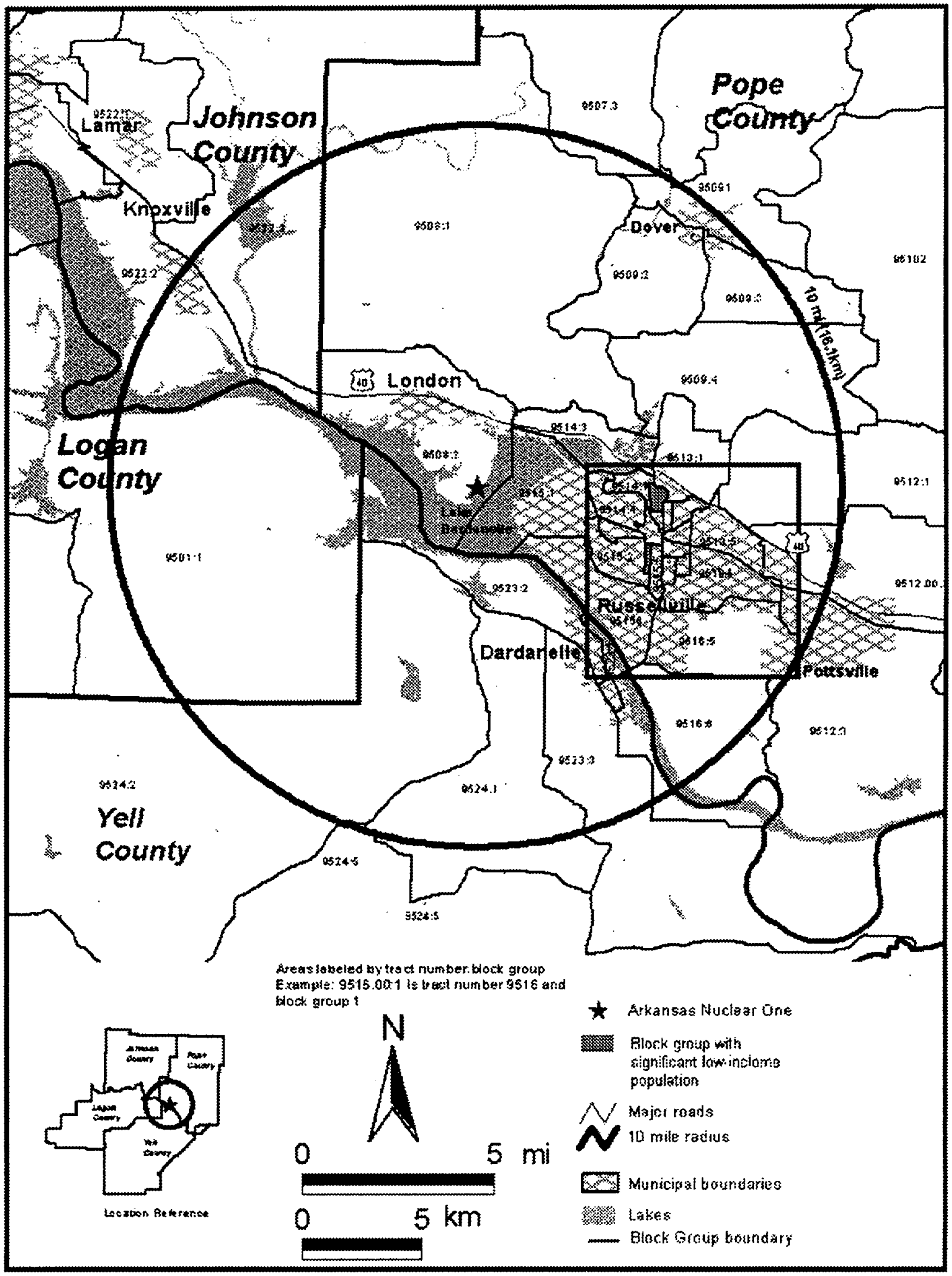

Figure 4.18-4, Block Groups – Low Income Household Review (Far-Field)

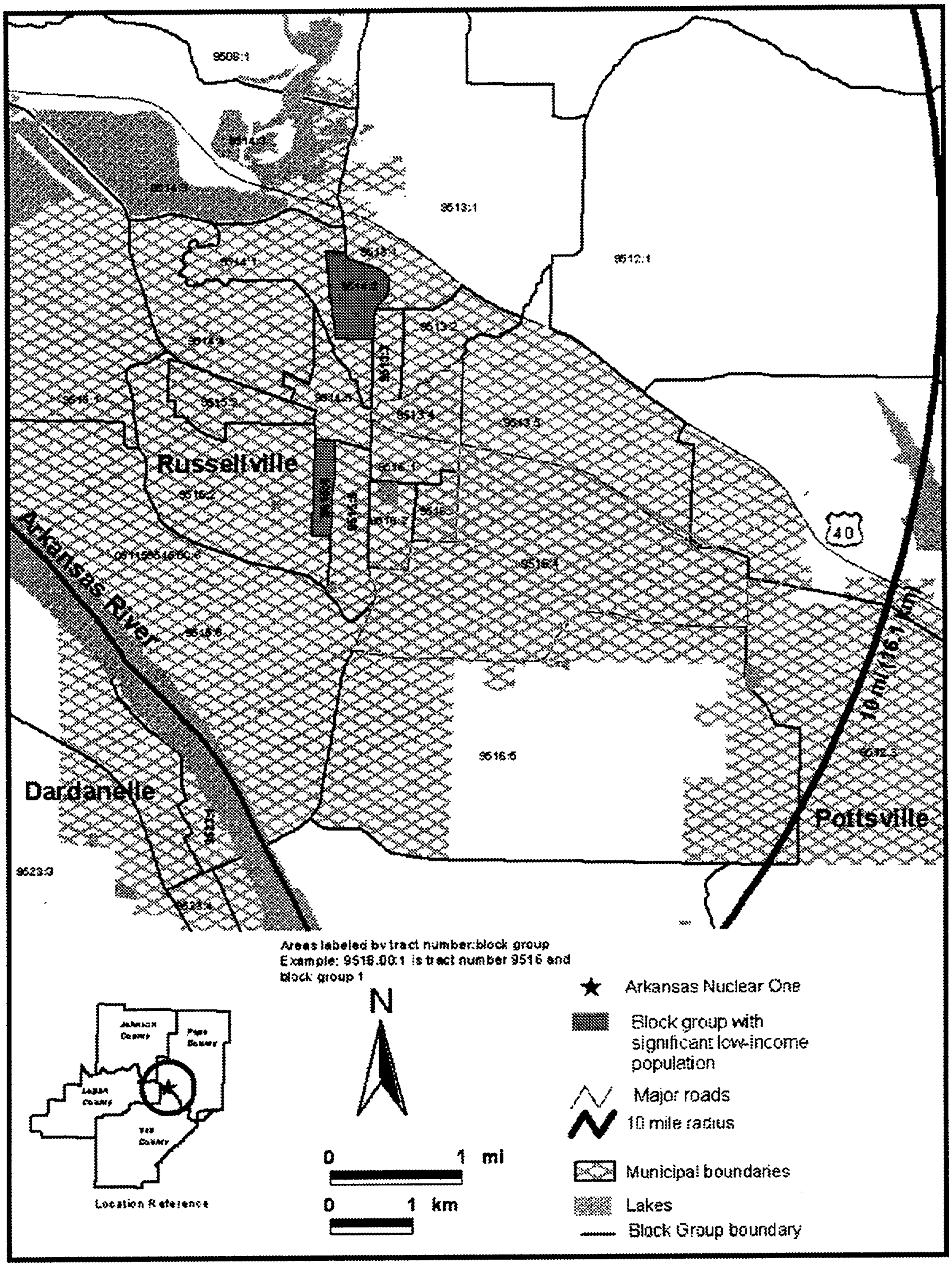

Figure 4.18-5, Block Groups – Low Income Household Review (Near-Field)

4.19 New and Significant Information

4.19.1 Requirement [10CFR51.53(c)(3)(iv)]

The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware.

4.19.2 Entergy Operations' Response

Entergy Operations performed a review of the environmental issues applicable to license renewal at ANO-1. This review was performed on Category 1 issues appearing in 10CFR Part 51, Subpart A, Appendix B, Table B-1 to verify that the GEIS conclusions remained valid with respect to ANO-1. Five independent consultants (environmental, technical, and legal) assisted in the preparation and/or review of the ER. A meeting was also held with various state agencies who were provided copies of the ER for review. Based on these reviews, Entergy Operations is not aware of new and significant information regarding the plant's environment or plant operations that would make a generic conclusion codified by the NRC for Category 1 issues not applicable for ANO-1, that would alter regulatory or GEIS statements regarding Category 2 issues, or suggest any other measure of license renewal environmental impact.

ANO environmental activities receive reviews at the corporate, peer group, and site levels. The peer group consists of environmental representatives from each of the Entergy Operations' nuclear sites and corporate personnel. New requirements are identified at the corporate level, assessed for impact at the peer group level, and implemented at the site level. Also, plant activities that could potentially affect the environment will continue to receive an environmental review per ANO procedures. These reviews assess the impacts on the environment as well as any necessary changes and/or additions to the permits listed in Table 7.2-1 of this ER.

5.0 ALTERNATIVES CONSIDERED

5.1 Introduction

The NRC regulations require that an applicant's environmental report discuss alternatives to a proposed action. [10CFR51.45(b)(3)] The intent of this review is to enable the Commission to consider the relative environmental consequences of the proposed action given the environmental consequences of other activities that also meet the purpose of the proposed action, as well as the environmental consequences of taking no-action at all [Reference 2]. For the purposes of license renewal, there are only two alternatives that meet the purpose of the action: the renewal of the operating license or the decision not to renew the operating license. This section identifies the alternatives considered.

5.2 Proposed Action

The proposed action is the renewal of the operating license of ANO-1. This action would provide the opportunity for Entergy Operations to continue to operate ANO-1 through the 20-year term of the renewed license, expiring in 2034. The review of the environmental impacts as required by 10CFR51.53(c)(3)(ii) was provided in Section 4.0. Based on these reviews, Entergy Operations concludes impacts from the continued operation of ANO-1 through the license renewal period (until 2034) would be small.

5.3 No-Action Alternative

The no-action alternative to the proposed action is a decision not to renew the original operating license for ANO-1. In the event that the ANO-1 operating license is not renewed, it is expected that ANO-1 will continue to operate up to the end of the existing operating license. A decision not to seek a renewal license would necessitate the replacement of a maximum dependable output generation capacity of 836 net megawatts with some other type of generation. The environmental impacts of the no-action alternative would be the impacts associated with the type of replacement power utilized. Because the environmental impacts would be transferred from one location to another, there would be no net benefit to the no-action alternative. The environmental impacts of these various types of replacement power are discussed in Section 6.0. In addition, there would likely be adverse financial and socioeconomic impacts from the decision not to renew the license, including local unemployment, loss of local property tax revenue, and higher energy costs.

5.4 Decommissioning

Every nuclear power plant is required to submit decommissioning plans within two years following permanent cessation of operation of each reactor or at least five years before expiration of each operating license, whichever occurs first, pursuant to the requirements of 10CFR50.54(b). Plant shutdown can occur anytime during the term of the operating license, regardless of whether or not the license has been renewed. The only difference between shutting down under the present operating license and shutting down during the renewal operating license period is the timing of the decommissioning activities. As reflected in the NRC's Category 1 finding, the impacts of decommissioning at the end of 40 years of operation are not expected to differ from those of decommissioning at the end of 60 years of operation. The environmental impacts of the termination of operations and decommissioning are addressed in Section 8.4 of the GEIS [Reference 2]. In addition, NUREG-0586 [Reference 38] provides an analysis of the environmental impacts from decommissioning. The environmental impacts of the termination of operations and decommissioning of ANO-1 are expected to be comparable to those environmental impacts described in NUREG-0586 [Reference 38].

The termination of ANO-1 operation would benefit, to some degree, the water resources in the area due to the discontinuation of the thermal discharges and other industrial and low-level radioactive liquid discharges. This benefit would only exist provided that another generating facility, using the same water resources, is not located on this site in the future.

As noted in Section 4.9, the transmission lines attributable to ANO-1 (other than the transmission lines connecting the turbine building to the switchyard) are part of the Entergy transmission system and would remain in service.

The termination of the operation of ANO-1 would eliminate the production of low-level and high-level radioactive waste. The termination of plant operations could have significant adverse impacts on the economic structure and tax base of communities surrounding the plant, due to the loss of the taxes from the facility and to the loss of direct and indirect jobs associated with ANO-1.

5.5 Alternatives

As stated in NUREG-1437, Vol. 1, Section 8.1, the "NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" [Reference 2]. For the purposes of the review of alternative energy sources for ANO-1, the following alternatives were not considered as reasonable replacement power:

- Wind
- Photovoltaic Cells
- Solar Thermal Power
- Hydroelectric Generation
- Geothermal
- Wood Waste (Biomass)
- Municipal Solid Waste

- Energy Crops
- Delayed Retirement of Non Nuclear Units
- Imported Power
- Conservation
- Combination of Alternatives

As discussed in more detail in Section 6.1 of this ER, these technologies were eliminated as possible replacement power alternatives for one or more of the following reasons:

- High land-use impacts - Some of the technologies listed above would require a large area of land and would thus require a green field siting plan. This would result in a greater environmental impact than continued operation of ANO-1.

- Low capacity factors - Some of the technologies identified above are not capable of producing a maximum dependable output generation capacity of 836 net MW(e) of power at high capacity factors. These generation technologies are used as peaking power sources, as opposed to base load power sources, and for this reason are unlikely resources.

- Geographic availability of the resource - Some of the technologies are not feasible because there is no feasible location in the Entergy service area.

- Emerging technology - Some of the technologies have not been proven as a reliable and cost-effective replacement of a large generation facility. Therefore, these technologies are typically used with smaller (lower MW(e)) generation facilities.

- Availability – There is no assurance of the availability of imported power. For the purposes of this review of alternatives to the proposed action, conventional coal-fired, oil and gas-fired combined cycle, and nuclear base load generating sources are considered to be currently available conventional base load technologies that would be considered to replace ANO-1 generation upon the termination of operation. The comparison of the environmental impacts of these technologies is discussed in detail in Section 6.0.

The following were considered as reasonable replacement power alternatives and are discussed in further detail in Section 6.2:

- Conventional Coal Fire Units
- Oil and Gas (Combined Cycle)
- Natural Gas (Combined Cycle)
- Nuclear Power

6.0 COMPARISON OF IMPACTS

For the purposes of the review of alternative energy sources, the following key assumptions have been made. These key assumptions are intended to simplify the evaluation, yet still allow the no-action alternative review to meet the intent of NEPA requirements and NRC environmental regulations.

- The goal of the proposed action (license renewal) is the production of at least 1000 MW(e) to replace ANO-1's maximum dependable generation capacity of 836 MW(e) base-load generation.
- The alternatives that do not meet the goal are not considered in detail.
- A reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only those electric generation sources that are technically feasible and commercially viable [Reference 2, GEIS Section 8.1].
- The time frame for the needed generation is 2014 through 2034.
- Power purchase is not considered a reasonable alternative because there is no assurance that the capacity or energy would be available.
- The three-year average annual capacity factor of ANO-1 is 89.9 percent. The capacity factor is expected to remain consistent with this value throughout the plant's operating life.
- The Commission decision regarding the issuance of the renewal operating license for ANO-1 occurs within approximately five years after the submittal of the application for renewal.

6.1 Alternatives Not Within the Range of Reasonable Alternatives

As stated in NUREG-1437, Vol. 1, Section 8.1, the "NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" [Reference 2]. Commonly known generation technologies considered reasonable by NRC are listed in the following paragraphs. However, these sources have been eliminated as "reasonable alternatives" to the proposed action because the generation of 836 net MW(e) of electricity as a base-load supply utilizing these technologies is not technologically feasible.

Wind

The average annual capacity factor for this technology was estimated at 21 percent in 1995 and is projected to be 29 percent in 2010. This low capacity factor results from the high degree of intermittence of wind energy in many locations [Reference 39]. Current energy storage technologies are too expensive to permit wind power plants to serve as large base-load plants. Wind energy has a large land requirement, approximately 150,000 acres (61,000 ha) of land to generate 1000 MW(e) of electricity. This eliminates the possibility of co-locating a wind energy facility with a retired nuclear power plant. A green-field siting plan would be required. This would have a large impact upon much of the natural environment in the affected areas [Reference 2, GEIS Section 8.3.1].

Photovoltaic Cells

The average annual capacity factor for PV cells is estimated at 25 percent. The use of PV cells for base-load capacity requires very large energy storage devices that are not feasible for shortage of sufficient electricity to meet the base-load generating requirements. This is very expensive generation, which prevents it from being competitive. This technology also has a high land-use impact which, like the wind technology, results in a large impact to the natural environment. It is estimated that 35,000 acres (14,000 ha) of land would be required to generate 1000 MW(e) of electricity [Reference 2, GEIS Section 8.3.2].

Solar Thermal Power

The average capacity factor for this technology is estimated to be between 25 and 40 percent annually. This technology, like PV cells, has high capital costs and lacks base-load capability unless combined with natural gas backup. It requires very large energy storage capabilities. Based upon solar energy resources, the most promising region of the country for this technology is the West. Land-use requirements again are high, 14,000 acres (6000 ha) for 1000 MW(e), which would result in large environmental impacts to the affected area [Reference 2, GEIS Section 8.3.3].

Hydroelectric Generation

Hydroelectric generated power has an average annual capacity factor of 46 percent. The capacity factor depends, to a large degree, on a combination of head and available water flow. A large scale hydroelectric plant of 1000 MW(e) would require approximately 1,000,000 acres (400,000 ha) of land, resulting in large environmental impacts. This option is not practical due to the large loss of environmental habitat [Reference 2, GEIS Section 8.3.4].

Geothermal

A geothermal electricity generating facility has an average annual capacity factor of approximately 90 percent and can be used to provide reliable base-load power. Geothermal plants may be located only in certain areas, such as the western United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. This technology is not widely used as base-load generation due to the limited geographic availability of the resource and the immature status of the technology [Reference 2, GEIS Section 8.3.5]. This technology is not applicable to the region where the replacement of 836 MW(e) is needed. There is no feasible location for geothermal generation within the Entergy service area.

Wood Waste (Biomass)

A wood burning facility can provide base-load power and operate with an average annual capacity factor of around 70 to 80 percent and with 20 to 25 percent efficiency. The cost of the fuels required for this type of facility is highly variable and very site-specific. The rough cost for construction of this type of facility in the ANO-1 area, where the replacement of 836 MW(e) is needed, is approximately $800/kW Among the factors influencing costs are the environmental considerations and restrictions which are influenced by public perceptions, easy access to fuel sources, and environmental factors. In addition, the technology is expensive and inefficient. Therefore, economics alone eliminate biomass technology as a reasonable alternative [Reference 2, GEIS Section 8.3.6].

Municipal Solid Waste

The initial capital costs for this technology are much greater than the comparable steam-turbine technology found at wood waste facilities. This is due to the need for specialized MSW handling and waste separation equipment and stricter environmental emissions controls. These facilities are typically used when landfill space is not available for handling the waste disposal needs of a community. High costs prevent this technology from being economically competitive. Thus, municipal solid waste generation is not a reasonable alternative [Reference 2, GEIS Section 8.3.7].

Energy Crops

This technology is comparable to the wood waste facilities. This technology is not currently cost competitive with fossil-fired alternatives. Energy crops are considered an emerging technology, not economically practicable, and are not a reasonable alternative to the license renewal [Reference 2, GEIS Section 8.3.8].

Delayed Retirement of Non-Nuclear Units

The delayed retirement of fossil generation sources could not be used to replace the generation capacity of 836 net MW(e) of ANO-1, since these sources are used for peaking and intermediate generation. Additionally, there is no guarantee that these fossil units could economically operate for an additional 20 years after the current decision dates. Entergy does not have plans to retire any of its base-load fossil plants. Therefore, delayed retirement of base-load fossil generation could not be used as an alternative to the license renewal. For these reasons, the delayed retirement of non-nuclear generating units is not considered as a reasonable alternative to license renewal for ANO-1.

Imported Power
Entergy currently uses purchased power contracts and/or other options. For the purposes of this evaluation, the power purchase option is not considered a reasonable replacement for the license renewal alternative. This is due to the fact that there is no assurance that sufficient capacity or energy would be available in the 2014 through 2034 time frame to replace the 836 net MW(e) base-load generation of ANO-1.

Conservation
The concept of conservation as a resource does not meet the primary NRC criterion "that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generations sources that are technically feasible and commercially viable." It is neither single, nor discrete, nor is it a source of generation. Conservation is unlike other resources in that it reduces the demand for energy as opposed to providing a source of energy to meet the demand. Although conservation has reduced the growth in demand for electricity used or needed in the country, it has not eliminated the need for new and existing generating capacity.

Combination of Alternatives
Even though individual alternatives might not be sufficient on their own to replace ANO-1 due to the small size of the resource (hydro) or lack of cost-effective opportunities (e.g., for conservation), it is conceivable that a mix of alternatives might be cost effective. For example, if some additional cost-effective conservation opportunities could be found and combined with a smaller imported power or natural gas-fired alternative, it might be possible to reduce some of the key environmental impacts of alternatives. However, it is unlikely that such a hypothetical mix could reduce the environmental impact significance level below SMALL. In comparison, the environmental impact significance level for renewing the ANO-1 license is SMALL on all dimensions.

6.2 Comparison of Environmental Impacts for Reasonable Alternatives

As stated in the GEIS, the "NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable" [Reference 2, GEIS Section 8.1]. Below is a discussion of the supply side alternative energy technologies that Entergy would likely utilize if the decision is made not to extend the license period for ANO-1. These alternatives are considered to be within the range of alternatives capable of replacement power for ANO-1's base-load generation. Conventional coal-fired, oil and gas-fired combined cycle, and nuclear base-load generating sources are considered to be currently available conventional base-load technologies that would be considered to replace ANO-1 generation upon its termination of operation.

These environmental impacts are for the construction and operation of these generation facilities. The impacts discussed do not include the additional environmental impacts from obtaining and transporting the fuel sources associated with these facilities. The continued operation of ANO-1 for the license extension period would result in less environmental impact than that of the replacement power which could be obtained from other reasonable generating sources, as described below, if license renewal were not pursued.

6.2.1 Conventional Coal Fired Units

The United States currently has an abundant supply of low-cost coal. For this reason, fossil-fired technology has been considered a reasonable alternative energy source. However, the Clean Air Act of 1990 has made it increasingly expensive to operate these types of facilities. The initial capital cost for construction of a conventional coal-fired unit is approximately \$800/kW, and the O&M costs are approximately \$3.65/MW/hr. The environmental impacts from the construction and operation of a conventional coal-fired plant are summarized in Table 6.2-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load coal unit. New base-load coal units would likely utilize closed loop cooling towers that would lessen the thermal impact of rejecting heat into lakes or streams. However, evaporation from the cooling towers would still be greater than that of ANO-1's once-through cooling system. There are no low-level radioactive waste discharges to surface water associated with a coal unit.

The solid wastes generated by a conventional coal-fired plant would be fly ash, bottom ash, SCR catalyst (used for NO_x control), and SO_2 scrubber sludge/waste. A coal facility of this size would generate significant amounts of ash on an annual basis. Approximately 70 percent of this would be fly ash and 30 percent would be bottom ash, dependent on the type of coal burned, the type of emission control equipment used, etc. The SCR would generate spent catalyst material that would have high concentrations of metals that are removed from the fly ash. A new coal-fired facility would also require SO_2 scrubbers to be installed as emission control equipment. This would also result in the generation of significant amounts of scrubber sludge on an annual basis.

The largest environmental impact from this type of generation would result from the air emissions. A conventional coal-fired facility of this size would emit significant quantities of sulfur dioxide, nitrogen oxide, particulate matter, carbon monoxide, volatile organic compounds, and carbon dioxide on an annual basis. Trace elements such as mercury, arsenic, chromium, beryllium, and selenium in the form of particulates and vapor would be emitted in small quantities. This energy source is not the most economical option that exists today. For this reason, a conventional coal-fired plant would not be considered as the first choice if license renewal were not pursued for ANO-1.

The issue of "Global Warming" is an obstacle to the utilization of coal as a reliable and long-term energy source. In a draft treaty developed December 10, 1997, in Kyoto Japan, the United States agreed to reduce the emissions of greenhouse gases (including CO_2) to 7 percent below the 1990 levels. This reduction would be phased in between the years 2008 and 2012. If this treaty is ratified and the legislation is passed that requires a reduction of this magnitude, the expanded use of coal as a reliable energy source may become impracticable due to restrictions on the levels of CO_2 emitted and the expected carbon taxes or emission caps. Other obstacles to the utilization of coal as a reliable and long term energy source are the new EPA 8-hour ozone standard (which is impacted by NO_x emissions), the new EPA $PM_{2.5}$ (particulate matter with a nominal size of less than 2.5 microns), and regional haze rules (which are impacted by SO_2).

In summary, a conventional coal-fired facility could provide replacement power for ANO-1's base-load generation. However, the air quality impacts would be greater than the impacts from continued operation of ANO-1, and the continued economic use of coal is uncertain due to the "global warming" issues. As shown in Table 6.2-1, the construction of a new facility would result in greater environmental impacts than the impacts associated with the proposed action (license renewal).

6.2.2 Oil and Gas (Combined Cycle)

Oil as a resource is not considered as a stand-alone fuel because it is typically not price competitive when natural gas is readily available. The capital cost for this type of facility is roughly \$380/kW, with an operation and maintenance cost of approximately \$30/MW/hr when used in combination with natural gas. The environmental impacts from the construction and operation of this type of facility are detailed in Table 6.2-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load oil and gas combined cycle unit. New base-load combined cycle units would likely utilize closed loop cooling towers that would lessen the thermal impact. However, evaporation from the cooling towers would still be greater than associated with ANO-1's once-through cooling system. There are no low-level radioactive waste discharges to surface water associated with a combined cycle unit.

The solid waste generated from this type of facility would be minimal. The only significant waste would be from spent SCR catalyst used for NOx control. The largest environmental impact from operating this type of facility would be from air emissions. Since it is not economical, oil would be used as an alternative fuel to gas, provided gas was available. Significant quantities of sulfur dioxide, nitrogen oxide, particulate matter, and carbon dioxide would be emitted on an annual basis when burning fuel oil. The use of oil as a stand-alone fuel source emits more CO_2 than the gas-fired alternative. The new 8-hour ozone standard, the $PM_{2.5}$ standard, regional haze rules, and the "Global Warming" issue, as discussed above, may make it difficult to use oil as a fuel source.

This alternative energy source is typically used with natural gas as the primary fuel and with oil used as a backup. Used this way, combined cycle becomes a viable alternative energy source. The environmental impacts associated with a gas-fired facility are detailed below.

6.2.3 Natural Gas (Combined Cycle)

The estimated capital cost for the construction of combined cycle gas turbines is roughly \$380/kW, with an O&M cost of approximately \$25/MW/hr. Note that this variable cost is largely dependent on the price of natural gas. Natural gas combined cycle units are generally considered to be the most economical of the new construction base-load generation technologies currently available. For this reason, natural gas is widely used. The environmental impacts resulting from the construction and operation of a maximum dependable output generation capacity of 836 net MW(e) combined cycle facility are summarized in Table 6.2.-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load natural gas combined cycle unit. New base-load combined cycle units would likely utilize closed loop cooling towers that would lessen the thermal impact of rejecting heat into lakes or streams. However, evaporation from the cooling towers would still be greater than that of ANO-1's once-through system. There are no low-level radioactive waste discharges to surface water associated with a combined cycle unit.

The solid waste generated from this type of facility would be minimal. The largest environmental impact would result from the air emissions. These emissions are based on burning natural gas throughout the year. This type of facility would emit nitrogen oxide, particulate matter, and carbon dioxide when burning natural gas. The new 8-hour ozone standard, $PM_{2.5}$, and regional haze rules will not be of concern with natural gas combined cycle because these units have low NOx emissions and no SO_2 emissions.

In summary, a natural gas-fired combined cycle facility would provide viable replacement power for ANO-1's base-load generation. However, the air quality impacts would be far greater than the impacts from the continued operation of ANO-1. As shown in Table 6.2-1, the construction of a new facility would result in greater environmental impacts than the impacts associated with the proposed action (license renewal).

6.2.4 Nuclear Power

The estimated capital cost for the construction of an ALWR nuclear facility is estimated at \$1530/kW, and the O&M cost is approximately \$3.76/MW/hr. For this reason, this technology is not economically feasible as an alternative to the continued operation of ANO-1 with a renewed license. The environmental impacts from an ALWR would be similar to the impacts that exist for ANO-1 today. However, construction of an ALWR would require a green-field site, which would have a larger impact on the environment than the license renewal option. The environmental impacts resulting from the construction and operation of a 1000 MW(e) ALWR are summarized in Table 6.2-1.

Table 6.2-1, Comparison of Environmental Impacts

Expected Environmental Impact [a]	Renewal of ANO-1 Operating License 836 MW(e)	Conventional Coal-Fired Fossil 1000 MW(e)	Combined Cycle Fuel Oil 1000 MW(e)	Combined Cycle Natural Gas 1000 MW(e)	Advanced Light Water Reactor 1000 MW(e)
Land Use	No additional impacts	700 ha (1700) acres needed	50 ha (120 acres) needed	45 ha (110 acres) needed	200 – 400 ha (500 - 1000 acres)
Ecology	No additional impacts	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging,; bird collisions
Aesthetics	No change	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions
Water Quality Impacts from Site Construction	None	Sediment from land clearing	Sediment from land clearing	Sediment from land clearing	Sediment from land clearing
Cooling Water Consumption	No change	860,000 m^3 (700 acre-ft) water used per quad (10^{12} Btu) energy produced	860,000 m^3 (700 acre-ft) water used per quad (10^{12} Btu) energy produced	817,000 m^3 (662 acre-ft) water used per quad (10^{12} Btu) energy produced	910,000 m^3 (740 acre-ft) water used per quad (10^{12} Btu) energy produced
Regulated Water Pollutants	40CFR Part 423 - Steam Electric Guidelines + low-level radwaste discharge	40CFR Part 423 - Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines + low-level radwaste discharge
Air Quality	Very little CO_2 or regulated pollutants	Emissions of CO_2, regulated pollutants, more than other technologies; also radionuclides	Emissions of CO_2, SO_2 and NO_x, regulated pollutants, radionuclides less than coal	Emissions of CO_2 and NO_x, regulated pollutants, radionuclides less than coal	Very little CO_2 or regulated pollutants
Waste	Spent fuel, low-level waste, mixed waste	Large amounts of fly ash, scrubber sludge and other solid waste	Moderate amounts of scrubber waste (less than coal) and particulates	Some solid waste	Spent fuel, slightly more mixed waste and low-level waste than license renewal
Human Health	Substantial public health improvement compared with conventional fossil plant; safety risks to workers	Public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	Some public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	Public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	<1% of natural radiation sources; safety risks to workers
Socioeconomic	Moderate employment and tax revenue	250 workers – moderate long term economic community benefits	200 workers – moderate long term economic, community benefits	150 workers – moderate long term economic, community benefits	700 workers – substantial long term economic, community benefits
Cultural	No change	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines

NOTES:

a = Based on NUREG-1437, Vol. 1, Table 8.2

6.3 Proposed Action Versus No-Action

The proposed action is the renewal of the ANO-1 operating license. The ANO-1 specific review of the twelve specific analytical requirements, as required by 10CFR51.53(c)(3)(ii), concluded that the impacts to the environment from the continued operation of ANO-1 through the license renewal period (until 2034) would be small.

The no-action alternative to the proposed action is the decision not to pursue renewal of the operating license for ANO-1. The environmental impacts of the no-action alternative would be the impacts associated with the construction and operation of the type of replacement power utilized. In effect, the environmental impacts would be transferred from being limited to the impacts of the continued operation of ANO-1, to the environmental impacts associated with the construction and operation of a new generation facility. Therefore, the no-action alternative would not have any net environmental benefits.

The environmental impacts associated with the proposed action (the continued operation of ANO-1) were compared to the environmental impacts from the no-action alternative (the construction and operation of other reasonable sources of electricity generation). Entergy believes this comparison shows that the continued operation of ANO-1 would produce fewer significant environmental impacts than the no-action alternative. There are significant differences in the impacts to air quality impacts and land-use impacts between the proposed action and the reasonable alternative generation sources. In addition, there would likely be adverse socioeconomic impacts to the area around ANO-1 from the decision not to pursue the license renewal, including local unemployment, loss of local property tax revenue, and higher energy costs.

The United States civilian nuclear power plants represent close to 20 percent of the nation's energy supply. The average age of U.S. commercial nuclear plants is between 20 and 25 years. Currently, the operating license of thirteen plants representing 11,700 MW(e) will expire in 2014. Early closure of nuclear facilities facing regulatory and economic uncertainties has resulted in the loss of approximately 6,000 MW(e) of emission free generating capacity over the past eight years. Making the decision to renew the operating license early in the life of the plant improves the economics of the remaining capital cost recovery and lengthens the time available to accumulate decommissioning funds [Reference 40].

The Joint DOE-Electric Power Research Institute Strategic Research and Development Plan to Optimize US Nuclear Power Plants states that "... nuclear energy was one of the prominent energy technologies that could contribute to alleviate global climate change and also help in other energy challenges including reducing dependence on imported oil, diversifying the U.S. domestic electricity supply system, expanding U.S. exports of energy technologies, and reducing air and water pollution." The Department of Energy agreed with this perspective and stated that "...it is important to maintain the operation of the current fleet of nuclear power plants throughout their safe and economic lifetimes"

[Reference 40]. The renewal of the ANO-1 operating license is consistent with these goals.

6.4 Summary

The proposed action is the renewal of the ANO-1 operating license. The proposed action would provide a maximum dependable generation capacity of at least 836 net MW(e) of base-load power through 2034. The results of the review of alternatives to the proposed action are summarized in Table 6.2-1. The environmental impacts of the continued operation of ANO-1 through 2034 are less than those impacts associated with the best case assessed among reasonable alternatives. This is primarily due to the air emissions associated with the alternatives that do not exist with ANO-1. As previously discussed and as shown in Table 6.2-1, the continued operation of ANO-1 would create significantly less environmental impact than the construction and operation of new base-load generation capacity. Finally, the continued operation of ANO-1 will have a significant positive economic impact on the communities surrounding the station.

7.0 STATUS OF COMPLIANCE

7.1 Requirement [10CFR51.45(d)]

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements that have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection."

7.2 Environmental Permits

Table 7.2-1 lists the environmental permits held by ANO and the compliance status of these permits. These permits will be in place as appropriate throughout the period of extended operation given their respective renewal schedules. Other than routine renewals required at frequencies specified by the permits in Table 7.2-1, no state, federal, or local environmental permits have been identified as being required for re-issuance to support the extension of the ANO-1 operating license. In addition, since ANO is not located in a municipality, no zoning or land-use restrictions apply. Also, ANO is in compliance with the permits listed in Table 7.2-1

Table 7.2-1, Arkansas Nuclear One Environmental Permits and Compliance Status

ANO Environmental Permits	Federal Act	Permitting Agency	Date Permit Issued/Expires
National Pollutant Discharge Elimination System Permit AR0001392	FWPCA Section 402	Arkansas Department of Environmental Quality	11/01/97 10/31/02
Air Permit 0090-AR-2	Clean Air Act - Section 112	Arkansas Department of Environmental Quality	11/29/94 No exp. date
Water Use Registration No. 4124	Not Applicable	Arkansas Soil and Water Conservation Commission	No issuance date No exp. date
Section 404 Permit 00241-5	Clean Water Act – Section 404	Department of Army/Corps of Engineers	03/27/97 No exp. date
Petroleum Storage Tank Registration (Facility 58000008)	RCRA Subtitle I	Arkansas Department of Environmental Quality	07/01/95 07/31/00
Petroleum Storage Tank Registration (Facility 58000009)	RCRA Subtitle I	Arkansas Department of Environmental Quality	07/01/95 07/31/00
Hazardous Materials Certificate of Registration	Hazardous Materials Transportation Act	Department of Transportation	06/30/99 06/30/00
Dardanelle Water Use Agreement Contract No. DACW03-71-0002	Title 10 USC Section 2668	Department of Army/Corps of Engineers	11/03/72 No exp. date
Nationwide Permit No. 00241-6	Rivers and Harbors Act – Section 10	Department of Army/Corps of Engineers	09/30/99 09/30/01

7.3 Environmental Permits - Discussion of Compliance

Station personnel are primarily responsible for monitoring and ensuring that ANO is in compliance with all of its environmental permits and applicable regulations. Sampling results are submitted to the appropriate agency. ANO has an excellent record of compliance with its environmental permits, including monitoring, reporting and operating within specified limits.

ANO has three ponds (lagoons) for treating domestic sewage wastewater and one emergency cooling pond for auxiliary cooling located on-site. These ponds are regulated under NPDES Permit AR0001392.

Entergy Operations has measures in place to ensure those environmentally sensitive areas or species of concern are adequately protected during site operations and project planning [Reference 41]. These measures include an environmental evaluation checklist and also establish controls and methods for evaluating potential environmental affects from plant operations and project planning. Therefore, planned projects or changes in plant operations would be required to undergo an environmental evaluation prior to implementation, with appropriate permits obtained as necessary.

Maintenance activities along transmission line right-of-ways are controlled through contracts established between Entergy and the contractor. The contract outlines contractors responsibilities regarding obtaining appropriate federal, state or local permits, including abiding with all applicable environmental laws. The primary management method used along the Entergy transmission line right-of-ways is mechanical clearing, with herbicide application only used minimally.

7.4 Other Licenses

The following additional licenses are listed:

Facility Operating License No. DPR-51 for ANO-1, Docket #50-313
Facility Operating License No. NPF-6 for ANO-2, Docket #50-368
Independent Spent Fuel Storage Installation Docket #72-13

8.0 REFERENCES

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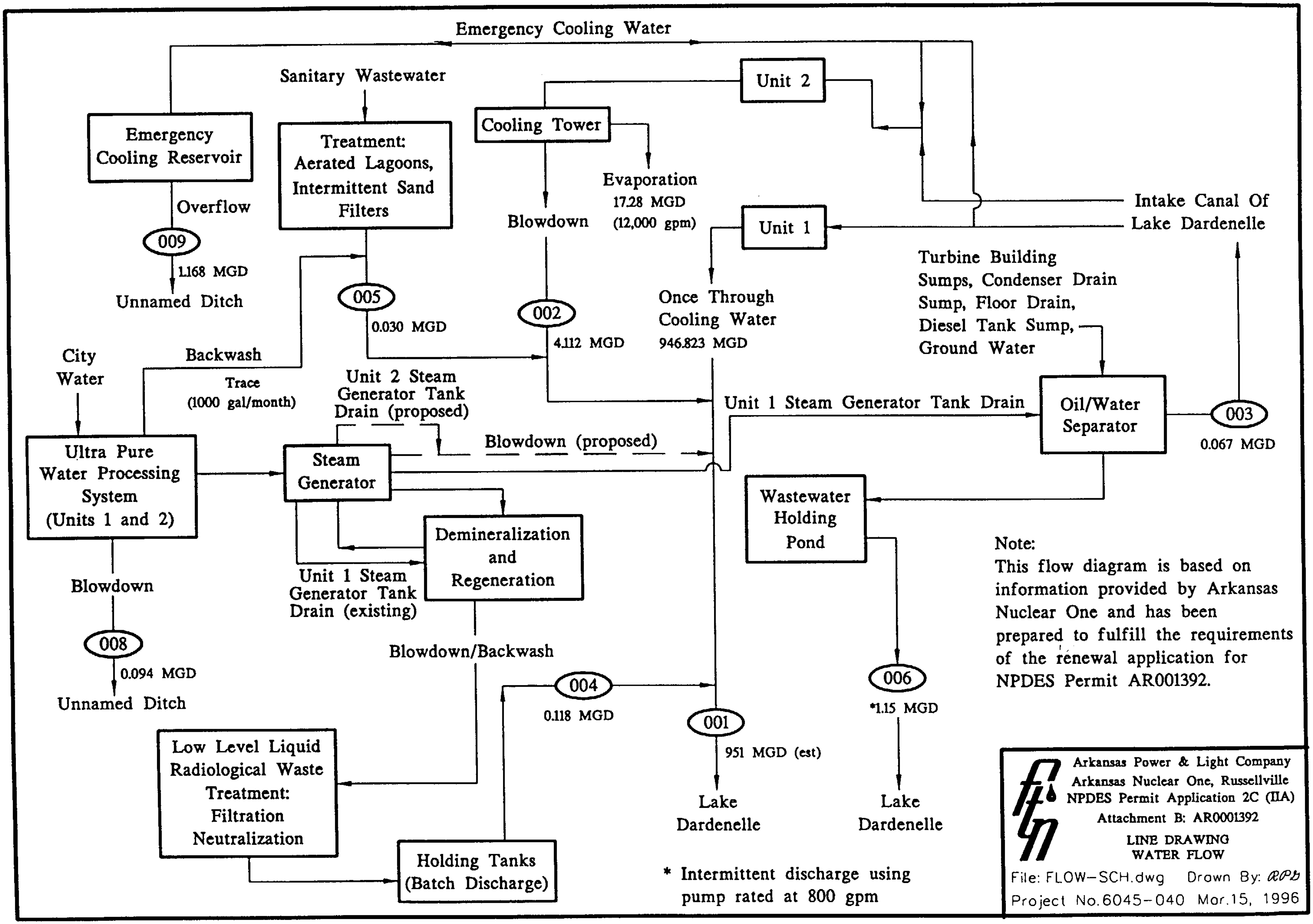
Attachment A

Water Flow Diagram


Emergency Cooling Water
Sanitary Wastewater
Unit 2
Emergency Cooling Reservoir
Treatment: Aerated Lagoons, Intermittent Sand Filters
Cooling Tower
Evaporation
17.28 MGD
(12,000 gpm)
Overflow
009
1.168 MGD
Unnamed Ditch
Blowdown
Unit 1
Intake Canal Of Lake Dardenelle
005
0.030 MGD
002
4.112 MGD
Once Through Cooling Water
946.823 MGD
Turbine Building Sumps, Condenser Drain Sump, Floor Drain, Diesel Tank Sump, Ground Water
City Water
Backwash
Trace
(1000 gal/month)
Unit 2 Steam Generator Tank Drain (proposed)
Unit 1 Steam Generator Tank Drain
Oil/Water Separator
003
0.067 MGD
Blowdown (proposed)
Ultra Pure Water Processing System (Units 1 and 2)
Steam Generator
Wastewater Holding Pond
Demineralization and Regeneration
Unit 1 Steam Generator Tank Drain (existing)
Blowdown
008
0.094 MGD
Unnamed Ditch
Blowdown/Backwash
004
0.118 MGD
001
951 MGD (est)
006
*1.15 MGD
Low Level Liquid Radiological Waste Treatment: Filtration Neutralization
Holding Tanks (Batch Discharge)
Lake Dardenelle
Lake Dardenelle
* Intermittent discharge using pump rated at 800 gpm
Note:
This flow diagram is based on information provided by Arkansas Nuclear One and has been prepared to fulfill the requirements of the renewal application for NPDES Permit AR001392.
Arkansas Power & Light Company
Arkansas Nuclear One, Russellville
NPDES Permit Application 2C (IIA)
Attachment B: AR0001392
LINE DRAWING
WATER FLOW
File: FLOW-SCH.dwg Drawn By: RPB
Project No.6045-040 Mar.15, 1996

Attachment B

NPDES Permit Number AR0001392, dated September 30, 1997

Permit number: AR0001392

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM AND THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT

In accordance with the provisions of the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended, Ark. Code Ann. 8-4-101 et seq.), and the Clean Water Act (33 U.S.C. 1251 et seq.),

Arkansas Nuclear One
1448 S.R. 333
Russellville, AR 72801

is authorized to discharge from a facility located at

Latitude: 35° 18' 49"; Longitude: 93° 13' 32"

approximately 1.5 miles south of I-40 and 3.5 miles northwest of the City of Russellville in Sections 27, 28, 33, and 34, Township 8 North, Range 21 West in Pope County, Arkansas.

to receiving waters named:

Outfall 001: Latitude: 35° 18' 31"; Longitude: 93° 13' 50"
Outfall 002: Latitude: 35° 18' 36"; Longitude: 93° 14' 03"
Outfall 003: Latitude: 35° 18' 34"; Longitude: 93° 13' 43"
Outfall 004: Latitude: 35° 18' 37"; Longitude: 93° 13' 48"
Outfall 005: Latitude: 35° 18' 32"; Longitude: 93° 14' 12"
Outfall 006: Latitude: 35° 18' 28"; Longitude: 93° 13' 49"
Outfall 007: Latitude: 35° 18' 28"; Longitude: 93° 14' 20"
Outfall 008: Latitude: 35° 18' 38"; Longitude: 93° 13' 54"
Outfall 009: Latitude: 35° 18' 49"; Longitude: 93° 14' 10"

Lake Dardanelle, an impoundment of the Arkansas River(Outfalls 001 through 007) and an unnamed ditch then to Lake Dardanelle (Outfalls 008 and 009)in Segment 3F of the Arkansas River Basin.

in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II (Version 2), III, and IV (Version 2) hereof.

This permit shall become effective on November 1, 1997

This permit and the authorization to discharge shall expire at midnight, October 31, 2002

Signed this 30th day of September, 1997

Chuck C. Bennett
Chief, Water Division
Arkansas Department of Pollution Control and Ecology

SECTION A. FINAL EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 001-once through cooling water, previously monitored effluent from outfalls 002, 004, 005, and 007, and unit 2 steam generator tank drain.

During the period beginning on the effective date and lasting through date of expiration , the permittee is authorized to discharge from outfall serial number 001. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Continuous	Record***
Total Residual Oxidants*	N/A	158.6	N/A	0.2 mg/l	Once/week	Grab
Oil and Grease (O&G)+++	N/A	N/A	10 mg/l	15 mg/l	Once/week	Grab
Temperature++	N/A	N/A	105 °F	110 °F	Continuous	Record
Chronic Biomonitoring**	N/A	N/A	N/A	N/A	Once/quarter	24-hr composite
pH+++	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/week	Grab

+ Report monthly average and daily maximum as MGD.
++ Instantaneous Maximum. See Conditions No. 7 and 14 of Part III.
+++ See Condition No. 5 of Part III.
* See Condition No. 9 of Part III.
** See condition No. 3 of Part III.
*** See Condition No. 2 of Part III.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 001.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 002-Cooling tower blowdown (Unit 2)

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 002. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Free available oxidants(FAO)*	0.75	1.88	0.2 mg/l	0.5 mg/l	Once/week	Grab
Zinc, Total++	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/month	24-hr composite
			Minimum	Maximum		
pH	N/A	N/A	6 s.u.	9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.
++ When discharging from the cooling tower blowdown. See Part III, Condition No. 4.
* See Part III, Condition No. 8.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 002.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 003-Oil/water separator

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 003. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

+ Report monthly average and daily maximum as MGD.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 003, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 004-Low volume wastes*

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 004. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Once/discharge	Calculate
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	15 mg/l	20 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Conditions No. 10 and 13 of Part III.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 004, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 005- treated sanitary wastewater and backwash water from ultra pure water system*

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 005. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Biochemical Oxygen Demand (BOD5)	N/A	N/A	30 mg/l	45 mg/l	Twice/month	Grab
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	45 mg/l	Twice/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 10 s.u.	Twice/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Part III, Condition No. 12.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 005, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 006-Wastewater holding pond (condenser drain sump, turbine building sump, floor drain and transformer area drain, and unit 1 steam generator tank drain)

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 006. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/week	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/week	Grab
			Minimum	Maximum		
pH	N/A	N/A	6 s.u.	9 s.u.	Once/week	Grab

\+ Report monthly average and daily maximum as MGD.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 006, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 007-Metal cleaning wastes

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 007. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Once/Batch*	Calculate
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/day*	Grab
Oil and Grease (O&G)	N/A	N/A	15 mg/l	20 mg/l	Once/day*	Grab
Copper, Total	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/day*	Grab
Iron, Total	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/day*	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/day*	Grab

\+ Report monthly average and daily maximum as MGD.
* When discharging.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 007, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 008-Blowdown from ultra pure water processing system

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 008. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Calculate*
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

+ Report monthly average and daily maximum as MGD.
* Calculate is implied as the difference between intake water and the process effluent.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 008, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 009-Emergency cooling pond

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 009. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement Frequency	Sample Type
	Monthly Avg	Daily Max	Monthly Avg	Daily Max		
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Estimate
Total Residual Oxidants(TRO)*	N/A	1.45	N/A	0.2 mg/l	Twice/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Twice/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Twice/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Part III, Condition No. 9.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 009.

SECTION B. SCHEDULE OF COMPLIANCE

The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

1. Compliance is required on the effective date of the permit.

2. The permittee shall submit progress reports for temperature in accordance with the following schedule:

	Activity	Compliance Date
1.	Submit progress report	11/1/1997
2.	Submit progress report	11/1/1998
3.	Submit final progress Report	11/1/1999

PART II — STANDARD CONDITIONS
SECTION A — GENERAL CONDITIONS

1. **Duty to Comply**
The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Water Act and the Arkansas Water and Air Pollution Control Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Any values reported in the required Discharge Monitoring Report which are in excess of an effluent limitation specified in Part I.A. shall constitute evidence of violation of such effluent limitation and of this permit.

2. **Penalties for Violations of Permit Conditions**
The Arkansas Water and Air Pollution Control Act provides that any person who violates any provisions of a permit issued under the Act shall be guilty of a misdemeanor and upon conviction thereof shall be subject to imprisonment for not more than one (1) year, or a fine of not more than ten thousand dollars ($10,000) or by both such fine and imprisonment for each day of such violation. Any person who violates any provision of a permit issued under the Act may also be subject to civil penalty in such amount as the court shall find appropriate, not to exceed five thousand dollars ($5,000) for each day of such violation. The fact that any such violation may constitute a misdemeanor shall not be a bar to the maintenance of such civil action.

3. **Permit Action**
This permit may be modified, revoked and reissued, or terminated for cause including, but not limited to, the following:
   a. Violation of any terms or conditions of this permit; or
   b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts; or
   c. A change in any conditions that requires either a temporary or permanent reduction or elimination of the authorized discharge; or
   d. A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination.
   e. Failure of the permittee to comply with the provisions of ADPCE Regulation No. 9 (Permit fees) as required by condition II A. 10 herein.

The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

4. **Toxic Pollutants**
Notwithstanding Part II.A.3., if any toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under Regulation No. 2, as amended (regulation establishing water quality standards for surface waters of the State of Arkansas) or Section 307(a) of the Clean Water Act for a toxic pollutant which is present in the discharge and that standard or prohibition is more stringent than any limitation on the pollutant in this permit, this permit shall be modified or revoked and reissued to conform to the toxic effluent standards or prohibition and the permittee so notified.

The permittee shall comply with effluent standards or prohibitions established under Regulation No. 2 (Arkansas Water Quality Standards), as amended, or Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

5. **Civil and Criminal Liability**
Except as provided in permit conditions on "Bypassing" (Part II.B.4.a.), and "Upsets" (Part II.B.5.b.), nothing in this permit shall be construed to relieve the permittee from civil penalties for noncompliance. Any false or materially misleading representation or concealment of information required to be reported by the provisions of this permit or applicable state and federal statutes or regulations which defeats the regulatory purposes of the permit may subject the permittee to criminal enforcement pursuant to the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

6. **Oil and Hazardous Substance Liability**
Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the Clean Water Act.

7. **State Laws**
Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Clean Water Act.

8. **Property Rights**
The issuance of this permit does not convey any property rights of any sort, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations.

9. **Severability**
The provisions of this permit are severable. If any provisions of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provisions to other circumstances, and the remainder of this permit, shall not be affected thereby.

10. **Permit Fees**
The permittee shall comply with all applicable permit fee requirements for wastewater discharge permits as described in ADPCE Regulation No. 9 (Regulation for the Fee System for Environmental Permits). Failure to promptly remit all required fees shall be grounds for the Director to initiate action to terminate this permit under the provisions of 40 CFR 122.64 and 124.5(d), as adopted in ADPCE Regulation No. 6, and the provisions of ADPCE Regulation No. 8.

SECTION B — OPERATION AND MAINTENANCE OF POLLUTION CONTROLS

1. **Proper Operation and Maintenance**
   a. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit.
   b. The permittee shall provide an adequate operating staff which is duly qualified to carry out operation, maintenance and testing functions required to insure compliance with the conditions of this permit.

2. **Need to Halt or Reduce Not a Defense**
It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. Upon reduction, loss, or failure of the treatment facility, the permittee shall, to the extent necessary to maintain compliance with its permit, control production or discharges or both until the facility is restored or alternative method of treatment is provided. This requirement applies, for example when the primary source of power for the treatment facility is reduced, is lost, or alternate power supply fails.

3. **Duty to Mitigate**
The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has reasonable likelihood of adversely affecting human health or the environment.

4. **Bypass of Treatment Facilities**
   a. Bypass not exceeding limitation. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Part II.B.4.b and 4.c.
   b. Notice
      (1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible, at least ten days before the date of the bypass.
      (2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in Part II.D.6(24-hour notice).
   c. Prohibition of bypass.
      (1) Bypass is prohibited and the Director may take enforcement action against a permittee for bypass, unless:
         (a) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;
         (b) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if the permittee could have installed adequate backup equipment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
         (c) The permittee submitted notices as required by Part II.B.4.b.
      (2) The Director may approve an anticipated bypass, after considering its adverse effects, if the director determines that it will meet the three conditions listed above in Part II.B.4.c.(1).

5. **Upset Conditions**
   a. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of Part II.B.5.b. of this section are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

b. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:
   (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
   (2) The permitted facility was at the time being properly operated;
   (3) The permittee submitted notice of the upset as required by Part II.D.6.; and
   (4) The permittee complied with any remedial measures required by Part II.B.3.

c. Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

6. **Removed Substances**
Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner such as to prevent any pollutant from such materials from entering the waters of the state. Written approval for such disposal must be obtained from the ADPCE.

7. **Power Failure**
The permittee is responsible for maintaining adequate safeguards to prevent the discharge of untreated or inadequately treated wastes during electrical power failure either by means of alternate power sources, standby generators, or retention of inadequately treated effluent.

SECTION C — MONITORING AND RECORDS

1. **Representative Sampling**
Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge during the entire monitoring period. All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other wastestream, body of water, or substance. Monitoring points shall not be changed without notification to and the approval of the Director. Intermittent discharges shall be monitored.

2. **Flow Measurements**
Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be selected and used to insure the accuracy and reliability of measurements of the volume of monitored discharges. The devices shall be installed, calibrated and maintained to insure the accuracy of the measurements are consistent with the accepted capability of that type of device. Devices selected shall be capable of measuring flows with a maximum deviation of less than $\pm$ 10% from true discharge rates throughout the range of expected discharge volumes and shall be installed at the monitoring point of the discharge.

3. **Monitoring Procedures**
Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at intervals frequent enough to insure accuracy of measurements and shall insure that both calibration and maintenance activities will be conducted. An adequate analytical quality control program, including the analysis of sufficient standards, spikes, and duplicate samples to insure the accuracy of all required analytical results shall be maintained by the permittee or designated commercial laboratory. At a minimum, spikes and duplicate samples are to be analyzed on 10% of the samples.

4. **Penalties for Tampering**
The Arkansas Water and Air Pollution Control Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate, any monitoring device or method required to be maintained under the Act shall be guilty of a misdemeanor and upon conviction thereof shall be subject to imprisonment for not more than one (1) year or a fine of not more than ten thousand dollars ($10,000) or by both such fine and imprisonment.

5. **Reporting of Monitoring Results**
Monitoring results must be reported on a Discharge Monitoring Report (DMR) form (EPA No. 3320-1). Permittees are required to use preprinted DMR forms provided by ADPCE, unless specific written authorization to use other reporting forms is obtained from ADPCE. Monitoring results obtained during the previous calendar month shall be summarized and reported on a DMR form postmarked no later than the 25th day of the month following the completed reporting period to begin on the effective date of the permit. Duplicate copies of DMR's signed and certified as required by Part II.d.11 and all other reports required by Part II.D. (Reporting Requirements), shall be submitted to the Director at the following address:

Director
Arkansas Department of Pollution
Control and Ecology
8001 National Drive
P.O. Box 8913
Little Rock, AR 72219-8913

If permittee uses outside laboratory facilities for sampling and/or analysis, the name and address of the contract laboratory shall be included on the DMR.

6. **Additional Monitoring by the Permittee**
If the permittee monitors any pollutant more frequently than required by this permit, using test procedures approved under 40 CFR 136 or as specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR. Such increased frequency shall also be indicated on the DMR.

7. **Retention of Records**
The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report or application. This period may be extended by request of the Director at any time.

8. **Record Contents**
Records and monitoring information shall include:
a. The date, exact place, time and methods of sampling or measurements, and preservatives used, if any;
b. The individual(s) who performed the sampling or measurements;
c. The date(s) analyses were formed;
d. The individual(s) who performed the analyses;
e. The analytical techniques or methods used; and
f. The measurements and results of such analyses.

9. **Inspection and Entry**
The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:
a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;
b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
d. Sample, inspect or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act, any substances or parameters at any location.

SECTION D — REPORTING REQUIREMENTS

1. **Planned Changes**
The permittee shall give notice and provide plans and specification to the Director for review and approval prior to any planned physical alterations or additions to the permitted facility. Notice is required only when:

For Industrial Dischargers
a. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in 40 CFR Part 122.29(b).
b. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements under 40 CFR Part 122.42(a)(1).

For POTW Dischargers:
c. Any change in the facility discharge (including the introduction of any new source or significant discharge or significant changes in the quantity or quality of existing discharges of pollutants) must be reported to the permitting authority. In no case are any new connections, increased flows, or significant changes in influent quality permitted that will cause violation of the effluent limitations specified herein.

2. **Anticipated Noncompliance**
The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

3. **Transfers**
The permit is nontransferable to any person except after notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the Act.

4. **Monitoring Reports**
Monitoring results shall be reported at the intervals and in the form specified in Part II.C.5. (Reporting). Discharge Monitoring Reports must be submitted even when no discharge occurs during the reporting period.

5. **Compliance Schedule**
Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date. Any reports of noncompliance shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

6. **Twenty-four Hour Report**
   a. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain the following information:
      (1) a description of the noncompliance and its cause;
      (2) the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and
      (3) steps taken or planned to reduce, eliminate and prevent reoccurrence of the noncompliance.
   b. The following shall be included as information which must be reported within 24 hours:
      (1) Any unanticipated bypass which exceeds any effluent limitation in the permit;
      (2) Any upset which exceeds any effluent limitation in the permit; and
      (3) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Director in Part III of the permit to be reported within 24 hours.
   c. The Director may waive the written report on a case-by-case basis if the oral report has been received within 24 hours.

7. **Other Noncompliance**
   The permittee shall report all instances of noncompliance not reported under Part II.D.4, 5, and 6, at the time monitoring reports are submitted. The reports shall contain the information listed at Part II.D.6.

8. **Changes in Discharge of Toxic Substances for Industrial Dischargers**
   The permittee shall notify the Director as soon as he/she knows or has reason to believe:
   a. That any activity has occurred or will occur which would result in the discharge, in a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(2)[48 FR 14153, April 1983, as amended at 49 FR 38046, September 26, 1984].
   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(2)[48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984].

9. **Duty to Provide Information**
   The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to detemine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit. Information shall be submitted in the form, manner, and time frame requested by the Director.

10. **Duty to Reapply**
    If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The complete application shall be submitted at least 180 days before the expiration date of this permit. The Director may grant permission to submit an application less than 180 days in advance but no later than the permit expiration date. Continuation of expiring permits shall be governed by regulations promulgated in ADPCE Regulation No. 6.

11. **Signatory Requirements**
    All applications, reports or information submitted to the Director shall be signed and certified.
    a. All permit applications shall be signed as follows:
       (1) For a corporation: by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means:
          (i) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or
          (ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.
       (2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or
       (3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:
          (i) the chief executive officer of the agency, or
          (ii) A senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.
    b. All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:
       (1) The authorization is made in writing by a person described above.
       (2) The authorization specified either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and
       (3) The written authorization is submitted to the Director.
    c. Certification. Any person signing a document under this section shall make the following certification:

       "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

12. **Availability of Reports**
    Except for data determined to be confidential under 40 CFR Part 2 and Regulation 6, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Department of Pollution Control and Ecology. As required by the Regulations, the name and address of any permit applicant or permittee, permit applications, permits and effluent data shall not be considered confidential.

13. **Penalties for Falsification of Reports**
    The Arkansas Air and Water Pollution Control Act provides that any person who knowingly makes any false statement, representation, or certification in any application, record, report, plan or other document filed or required to be maintained under this permit shall be subject to civil penalties specified in Part II.A.2. and/or criminal penalties under the authority of the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

PART III
OTHER CONDITIONS

1. The operator of this wastewater treatment facility shall be licensed by the State of Arkansas in accordance with Act 1103 of 1991, Act 556 of 1993, Act 211 of 1971, and Regulation No. 3, as amended.

2. Discharge flow for this outfall to be calculated based on pump capacity and run times plus the sum of all other contributing flows (Outfall 002, 004,005, and 007).

3. **Chronic Biomonitoring Requirements**

   a. Scope

   The permittee shall test Outfall **001** for toxicity in accordance with the provisions in this section. Such testing will determine if an effluent sample dilution affects the survival and/or reproduction or growth of the appropriate test organism.

   The first toxicity test must be initiated within 60 days from the effective date of the permit and the results of the test submitted with the first Discharge Monitoring Report (DMR) following completion of the toxicity test. However, if lethality is demonstrated for either test organism in any toxicity test required by this permit, the test results must be submitted to the Department within 15 days of receipt of results.

   The toxicity tests specified herein shall be conducted once per quarter.

   b. Definitions

   <u>Toxicity</u> is herein defined as a statistically significant difference at the 95% confidence level between the survival, reproduction or growth of the appropriate test organism in a specified effluent dilution and the control (0% effluent).

   <u>Lethality</u>, a component of toxicity, is herein defined as a statistically significant difference at the 95% confidence level between the survival of the appropriate test organism in a specified effluent dilution and the

control (0% effluent).

Significant nonlethal effect, a component of toxicity, is herein defined as a statistically significant difference at the 95% confidence level between the reproduction or growth of the appropriate test organism in a specified effluent dilution and the control (0% effluent).

Toxicity Reduction Evaluation (TRE) is an evaluation intended to determine those actions necessary to achieve compliance with water quality-based effluent limitations by reducing an effluent's toxicity or chemical concentration(s) to acceptable levels. A TRE is defined as a step-wise process which combines toxicity testing and analyses of the physical and chemical characteristics of a toxic effluent to identify the constituents causing effluent toxicity and/or determine the treatment methods which will reduce the effluent toxicity.

c. Test Methods

All test organisms, procedures, and quality assurance requirements used shall be in accordance with the latest revision of "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof, unless specified otherwise in the permit. The following tests shall be used:

i. Chronic static renewal survival and reproduction test using *Ceriodaphnia dubia* (Method 1002.0). This test should be terminated when 60% of the surviving females in the control produce three broods.

ii. Chronic static renewal 7-day larval survival and growth test using fathead minnow (*Pimephales promelas*) (Method 1000.0). A minimum of five (5) replicates with eight (8) organisms per replicate must be used for this test.

d. Test Acceptance

i. The toxicity test control (0% effluent) must have a survival equal to or greater than 80%. Should the control survival be less than 80%, the toxicity test, including control and all effluent dilutions, shall be repeated.

ii. The mean number of *Ceriodaphnia dubia* neonates produced per surviving female in the control (0% effluent) must be 15 or more. Should the control neonate production be less than 15, the toxicity test, including control and all effluent dilutions, shall be repeated.

iii. The average weight of surviving fathead minnow larvae at the end of the 7 days in the control (0% effluent) must be 0.25 mg or greater. Should the average larval weight be less than 0.25 mg, the toxicity test, including control and all effluent dilutions, shall be repeated.

iv. The percent coefficient of variation between replicates shall be 40% or less in the control (0% effluent) for:

(1) the young of surviving females in the *Ceriodaphnia dubia* reproduction test;
(2) fathead minnow growth test; and
(3) fathead minnow survival test.

v. The percent coefficient of variation between replicates shall be 40% or less for the low flow dilution (critical dilution) for ADPC&E to agree with a finding of no toxicity for these dilutions.

vi. If the permittee has conducted toxicity testing prior to the effective date of the permit in accordance with the provisions of this section, the test results may be submitted to ADPCE for approval. If approved, the test(s) will constitute partial fulfillment of the toxicity testing requirements of the permit.

e. Statistical Interpretation

i. For the *Ceriodaphnia dubia* survival test, the statistical analyses used to determine if there is a significant difference between the control and the low flow (Critical) dilution shall be Fisher's Exact Test as described in the "Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof.

ii. For the *Ceriodaphnia dubia* reproduction test and the fathead minnow larval survival and growth test, the statistical analyses used to determine if there is a significant difference between the control and the low flow (critical dilution) effluent concentration shall be in accordance with the methods for determining the No Observed Effect Concentration (NOEC) as described in the "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof.

f. Dilution Series

Five dilutions in addition to a control (0% effluent) composed of the same water as the dilution water, shall be used in the toxicity tests. These additional effluent dilutions shall be **32%, 42%, 56%, 75%, and 100%.** The low-flow effluent concentration (critical dilution) is defined as **100%** effluent.

g. Dilution Water

Dilution water used in the toxicity tests will be receiving water from Lake Dardanelle collected as close to the point of discharge as possible but unaffected by the discharge. If there is no receiving water due to zero flow conditions, the permittee may substitute synthetic dilution water.

If the receiving water is unsatisfactory as a result of preexisting instream toxicity (fails to fulfill the criteria of item 3.d. above, or for other reasons substantiated by the permittee) synthetic dilution water may be substituted for the receiving water, provided the following stipulations are met:

i. a synthetic dilution water control is run;

ii. the synthetic dilution water fulfills the requirements of item 3.d;

iii. A receiving water control is run concurrently with the test (provided sufficient receiving water is available), until receiving water toxicity is adequately documented to the Department.

iv. the permittee submits all test results indicating receiving water toxicity with the report and information required by item 3.m and the Discharge Monitoring Report (DMR); and

v. the synthetic dilution water shall have a pH, hardness and alkalinity similar to that of the receiving water and shall be prepared in accordance with the procedures in EPA/600/4-89/001 using ecoregion water characteristics as follows:

For discharges located in the Gulf Coastal, Arkansas River Valley, Boston Mountains, or Ouachita Mountains Ecoregions, and discharges to the Ouachita River, use <u>SOFT</u> water:

For discharges located in the Delta or Ozark Highlands Ecoregions, and discharges to the White, Arkansas, Mississippi, and St. Francis Rivers, use <u>MODERATELY HARD</u> water:

For discharges to the Red River, use <u>HARD</u> water.

Synthetic dilution water may be used in all subsequent tests for both test species provided all of the above stipulations are met.

h. Samples and Composites

A minimum of three flow-weighted 24-hour composite samples representative of the dry weather flows during normal operation will be collected from Outfall 001. A 24-hour composite sample consists of a minimum of twelve (12) effluent portions collected at equal time intervals and combined proportional to flow or a sample continuously collected proportional to flow over a 24-hour operating day.

The 24-hour composite samples must be collected such that the samples include any periodic episode of chlorination, use of a biocide or other potentially toxic substance discharged on an intermittent basis.

i. When collecting composite samples for toxicity testing, the permittee shall also analyze effluent for all parameters as specified in Part 1, Section A of this permit. These analyses may be utilized as those required in Part 1, Section A for the monitoring period encompassing the toxicity test or may be in addition to the requirements of Part 1, Section A, at the permittee's discretion. The results of these analyses shall be included in the reports required in item 3.m below.

The 24-hour composite samples must be collected so that the maximum holding time for any effluent sample shall not exceed 72 hours. The toxicity test must be initiated within 36 hours after the collection of the last portion of the first 24-hour composite sample. Samples shall be chilled to 4 degrees Centigrade during collection, shipping and/or storage.

If the flow from the outfall(s) being tested ceases during the collection of effluent samples, the requirements for the minimum number of effluent samples, the minimum number of effluent portions and the sample holding time are waived during that sampling period. However, the permittee must collect an effluent composite sample volume that is sufficient to complete the required toxicity tests with daily renewal of effluent.

j. Low Flow Lethality Testing - Special Conditions

The requirements of this subsection (item 3.j) apply only when a toxicity test at the **100%** effluent concentration demonstrates lethality.

i. The permittee shall conduct a total of two additional tests (retests) for any species that demonstrates significant lethal effects at the **100%** effluent concentration. The retests shall be conducted monthly during the next two consecutive months. The permittee shall not substitute a retest in lieu of routine toxicity testing, unless the specified testing frequency for the species demonstrating significant lethal effects is monthly. All retest data shall be submitted within 15 days of each test completion.

ii. If the results of the increased testing indicate lethality in the effluent at low flow dilution, the permittee shall submit a plan for a Toxicity Reduction Evaluation (TRE) and shall continue toxicity testing at a frequency of once per month for the species showing lethality, using the sample protocols as specified above until notified otherwise by the Department. The TRE plan, including a proposed implementation schedule, shall be submitted to the Department within 60 days of receipt of the results of the verification testing showing a lethal effluent. The plan will be reviewed by the Department. If deemed acceptable, the permittee shall be notified and the TRE plan shall become a requirement of this permit. Incomplete or unsatisfactory TRE plans and/or schedules will be returned to the permittee for correction of deficiencies. Failure to correct identified deficiencies within 30 days shall be considered a violation of this permit.

iii. The permittee shall conduct the TRE in accordance with the approved schedule and, upon completion, the permittee shall prepare a report which contains, at a minimum:

(1) the source of the toxicity (e.g. constituents; class of toxicants, suspected industrial contributors, etc.);

(2) results of any treatability studies conducted;

(3) discussion of alternative treatment or management techniques to reduce or eliminate toxicity;

(4) selection of the appropriate course of action to be followed by the permittee;

(5) an implementation schedule for making any required changes to reduce/eliminate toxicity.

iv. Upon completion of the TRE, the permittee shall select an appropriate course of action to reduce or eliminate the toxicity, and shall submit an application for modification of this permit, if applicable, including a proposed schedule for accomplishment. Additionally, if recommended solutions include construction or modification of the treatment system, an application for a construction permit shall also be submitted. The above applications shall be submitted within 90 days of completion of the TRE.

v. If none of the retests demonstrate significant lethality, the permittee shall return to the testing frequency specified in Item 3.a.

k. Low Flow Nonlethal Effects Testing - Special Conditions

The requirements of this subsection (item 3.k) apply only when a toxicity test demonstrates a significant nonlethal effect at the **100%** effluent concentration, **and** the test does not demonstrate a significant lethal effect as described in item 3.j. above.

i. Quarterly or Semi-Annual Testing: If the frequency of testing specified in this permit is quarterly or semi-annual, the permittee shall conduct a total of two (2) additional tests (retests) **for the species that demonstrated the significant nonlethal effects.** The retests shall be conducted monthly during the next two consecutive months. The permittee shall not substitute a retest in lieu of routine toxicity testing. If one of the retests shows significant non-lethal effects at the **100%** effluent concentration, the permittee may suspend the retesting for this reporting period and shall notify ADPCE in writing. All retest results shall be submitted to ADPCE within fifteen (15) days of test completion. After submitting the results which demonstrate significant non-lethal effects in one of the retests, and at the discretion of ADPCE, the permittee may be required to biomonitor for both species at an increased frequency of once per month for twelve (12) consecutive months; however, as a minimum, the permittee shall be required to biomonitor at least once per six (6) months for the remainder of the permit duration. The duration and frequency of biomonitoring will be stated in writing to the permittee.

If none of the retests demonstrate significant toxicity (lethal and nonlethal effects), the permittee shall return to the original testing frequency until fulfillment of the first year testing requirements. After the completion of the first year requirements, the permittee shall continue testing at a frequency of once per six (6) months.

ii. Monthly Testing: If the frequency of testing specified in item 3.a. is monthly, the permittee will continue testing monthly until the completion of the first year requirement and then test at a frequency of once per six (6) months for the duration of the permit.

l. No Toxicity Certification

If the toxicity tests for specific test organism(s) do not indicate toxicity at the **100%** effluent concentration during the first year or four consecutive test (whichever occurs later), the permittee shall certify this information in writing to ADPCE, and the biomonitoring requirements for that organism(s) may be reduced upon written authorization by the Department.

m. Reporting

i. The permittee shall prepare a full report of the results according to the Report Preparation Section of "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms". The full report must be submitted with the first DMR containing these biomonitoring results. Subsequent reports accompanying DMRs need include only sections 9.4 (Test Methods) and 9.7 (Results) of the full report prepared for the appropriate toxicity test, unless the full report is specifically requested by ADPCE. However, the full report shall be retained pursuant to the provisions of Part II.C.7 of this permit.

ii. The permittee shall submit the toxicity testing information contained in the summary sheet provided by ADPCE along with the DMR submitted for the end of the reporting period following each toxicity test.

n. Permit Reopener Conditions

This permit may be reopened to require effluent limits, additional testing, and/or other appropriate actions to address toxicity. Accelerated or intensified toxicity testing and/or a TRE may be required in accordance with Section 308 of the Clean Water Act, and the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

4. If any individual analytical test results is less than the minimum quantification level (MQL) listed below, a value of zero (0) may be used for that individual result for the Discharge Monitoring report (DMR) calculations and reporting requirements.

Pollutant	EPA Method	MQL (µg/l)
Zinc,Total	200.7	20

The permittee may develop a matrix specific method detection limit (MDL) in accordance with Appendix B of 40 CFR Part 136. For any pollutant for which the permittee determines a site specific MDL, the permittee shall send to ADPC&E, NPDES Permits Branch, a report containing QA/QC documentation, analytical results, and calculations necessary to demonstrate that a site specific MDL was correctly calculated. A site specific minimum quantification level (MQL) shall be determined in accordance with the following calculation:

$$MQL = 3.3 \times MDL$$

Upon written approval by the NPDES Permits Branch, the site specific MQL may be utilized by the permittee for all future Discharge Monitoring Report (DMR) calculations and reporting requirements.

5. If the sampling results at outfall 001 for oil and grease (O&G) and/or pH are below permit limitations during the first six months, the permittee shall certify this information in writing to ADPCE, so monitoring and reporting requirements for O&G and/or pH can be reduced upon written authorization by the Department without a major modification.

6. There shall be no discharge of **polychlorinated biphenyls** transformer fluid.

7. Daily average temperature is defined as the average of the

temperature measurement taken at equal time intervals not greater than two hours over the course of an operating day. The daily average temperature reported in the discharge monitoring reports (DMRs) for the month shall be the highest daily average temperature computed during the month.

8. The term "Free Available Oxidant" shall mean the value obtained using the amperometric titration method for free available chlorine described in the latest EPA approval edition of "Standard Methods for the Examination of Water and Wastewater" for total residual chlorine described in 40 CFR Part 136 for free available chlorine.

   Neither free available oxidant nor total residual oxidant may be discharged from any unit for more than **two hours** per day in any one day and not more than **one unit** in any plant may discharge free available or total residual oxidant at any one time unless the discharger demonstrates to the permitting authority that the units in a particular location cannot operate at or below the limits specified in this permit.

9. The term "Total residual oxidant" means the value obtained using the amperometric method for total residual chlorine as described in 40 CFR Part 136.

   Total residual oxidants may not be discharged from any single generating unit for more than **two hours** per day unless the permittee demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertibrate control.

10. The term "low volume waste sources" means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established. Low volume wastes sources include, but are not limited to : wastewaters from wet scrubber air pollution control systems, ion exchange water treatment system, water treatment evaporator blowdown, laboratory and sampling wastes, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems. Sanitary and air conditioning wastes are not included.

11. There shall be no discharge of cooling tower maintenance chemicals which contain the 129 priority pollutants (Appendix A of 40 CFR Part 423.)

12. Periodic discharge of maintenance chemicals (HCL, H2O2,

C6H8O7, NaCL, and NaOH)) from cleaning the ultra pure water processing system is authorized through outfall 005, provided the maintenance chemicals are first neutralized (pH 6-9) and then discharge at a rate that will not overload the hydraulic capacity or create a shock load on the sewage treatment plant.

13. Sampling of only one of the eight tanks that make up this outfall is necessary to meet the requirements of this outfall.

14. **Permit Reopener Condition:**

Stations 3, 5, and 10 shall be monitored for temperature twice/month in June, July, August, and September at a depth of three(3) feet for a period of three years . Stations 3, 5, and 10 refer to figure 1 of the letter dated April 24, 1997 which was submitted by ANO. This information must be submitted to ADPCE in accordance with the schedule of compliance in tabular form (See below). This permit shall be modified, or alternatively, revoked and reissued, to comply with any applicable provision of these requirements. If monitoring and reporting requirements indicate that different effluent limits and/or water quality limits for temperature are appropriate, the permit will be reopened and effluent limits revised.

Month	Date	Station		
		3	5	10
June				
June				
July				
July				
August				
August				
September				
September				

15. **Storm Water Pollution Prevention Plans:**

A storm water pollution prevention plan shall be developed for each facility covered by this permit. Storm water prevention plans shall be prepared in accordance with good engineering practices. The plan shall identify potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges associated with industrial activity from the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. Facilities must implement the provisions of the pollution prevention plan required under this part as a condition of this permit.

a. <u>Deadline for Pollution Prevention Plan Preparation and Compliance</u>.

   i. The Pollution Prevention Plan for storm water discharge associated with industrial activity:

      (1) shall be prepared on or before 60 days after issuance (and updated as appropriate);

      (2) shall provide for implementation and compliance with the terms of the plan on or before 180 days after issuance;

   ii. Upon a showing of good cause, the Director may establish a later date in writing for preparing and coming into compliance with a Pollution Prevention Plan for a storm water discharge associated with industrial activity.

b. <u>Signature and Plan Review</u>

   i. The plan shall be signed in accordance with Part III.15.d.vii (signatory requirements), and shall be retained on site at the facility which generates the storm water discharge in accordance with Part III.15.d.vi (retention of records) of this permit.

   ii. The permittee shall make plans available upon request to the Director, or authorized representative, or in the case of a storm water discharge associated with industrial activity which discharges through a municipal separate storm sewer system to the operator of the municipal system.

iii. The Director, or authorized representative, may notify the permittee at any time that the plan does not meet one or more of the minimum requirements of this Part. Within 30 days of such notification, or as otherwise provided by the Director, the permittee shall make changes to the plan and submit to the Director a written certification that the requested changes have been made.

c. Keeping Plans Current. The permittee shall amend the plan whenever there is a change in design, construction, operation, or maintenance, which has a significant affect on the potential for the discharge of pollutants to the waters of the State or if the storm water pollution prevention plan proves to be ineffective in eliminating or significantly minimizing pollutants from sources identified under Part III.15.d.ii (description of potential pollutant sources), or in otherwise achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Amendments to the plan may be reviewed by ADPCE in the same manner as Part III.15.b (signature and plan review) above.

d. The plan shall include, at a minimum, the following items:

i. Pollution Prevention Team. Each plan shall identify specific individual or individuals within the facility organization as members of a storm water Pollution Prevention Team that are responsible for developing the plan and assisting the facility or plant manager in its implementation, maintenance and revision. The plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's storm water pollution prevention plan.

ii. Description of potential pollutant sources. Each plan shall provide a description of potential sources which may be reasonably expected to add significant amounts of pollutants to storm water discharges or which may result in the discharge of pollutants during dry weather from separate storm sewers draining the facility. Each plan shall identify all activities and significant materials which may potentially be significant pollutant sources. Each plan shall include, at a minimum;

(1) Drainage:

(a) A site map indicating an outline of the drainage area of each storm water outfall that are within the facility boundaries, each existing structural control measure to reduce pollutants in storm water runoff, surface water bodies, locations where significant materials are exposed to precipitation, locations where major spills or leaks identified under Part III.15.d.ii.3(spills and leaks) of this permit have occurred, and the locations of the following activities where such activities are exposed to precipitation: fueling stations, vehicle and equipment maintenance and/or cleaning areas, loading/unloading areas, locations used for the treatment, storage or disposal of wastes, liquid storage tanks, processing areas and storage areas.

(b) For each area of the facility that generates storm water discharges associated with industrial activity with a reasonable potential for containing significant amounts of pollutants, a prediction of the direction of flow, and identification of the types of pollutants which are likely to be present in storm water discharges associated with industrial activity. Factors to consider include the toxicity of chemicals; quantity of chemicals used, produced or discharged; the likelihood of contact with storm water; and the history of significant leaks or spills of toxic or hazardous pollutants. Flows with a significant potential for causing erosion shall be identified.

(2) Inventory of Exposed Materials:

An inventory of the types of materials handled at the site that potentially may be exposed to precipitation. Such inventory shall include a narrative description of significant materials that have been handled, treated, stored, or disposed in a manner to allow exposure to storm water between the time three years prior to the effective date of this permit and the present; method and location of on-site storage and disposal; materials management practices employed to minimize contact of these materials with storm water runoff between the time of three years prior to the effective date of this permit and the present; the location and a description of existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and a description of any treatment the storm water receives.

(3) Spills and Leaks:

A list of significant spills and significant leaks of toxic or hazardous pollutants that occurred at areas exposed to precipitation or that otherwise drain to a storm water conveyance at the facility after the date of three years prior to the effective date of this permit. Such list shall be updated as appropriate during the term of the permit.

(4) Sampling Data:

A summary of existing discharge sampling data describing pollutants in storm water discharges from the facility, including a summary of sampling data collected during the term of this permit.

(5) Risk Identification and Summary of Potential Pollutant Sources:

A narrative description of the potential pollutant sources at the following areas:

loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; significant dust or particulate generating processes; and on-site waste disposal practices. The description shall specifically list any significant potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter (e.g. biochemical oxygen demand, etc.) of concern shall be identified.

iii. <u>Measures and Controls</u>. Each facility covered by this permit shall develop a description of storm water management controls appropriate for the facility, and implement such controls. The appropriateness and priorities of controls in a plan shall reflect identified potential sources of pollutants at the facility. The description of storm water management controls shall address the following minimum components, including a schedule for implementation:

(1) <u>Good Housekeeping</u>. Good housekeeping requires maintenance of areas which may contribute pollutants to storm water discharges in a clean, orderly manner.

(2) <u>Preventive Maintenance</u>. A preventive maintenance program shall involve inspection and maintenance of storm water management devices (cleaning oil/water separators, catch basins, etc.) as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters, and ensuring appropriate maintenance of such equipment and systems.

(3) <u>Spill Prevention and Response Procedures</u>. Areas where potential spills which can contribute pollutants to storm water discharges can occur, and their accompanying drainage points shall be identified clearly in the storm water pollution prevention plan. Where appropriate, specifying material handling procedures, storage requirements and use of equipment such as diversion valves in

the plan should be considered. Procedures for cleaning up spills shall be identified in the plan and made available to the appropriate personnel. The necessary equipment to implement a clean up should be available to personnel.

(4) Inspections. In addition to or as part of the comprehensive site evaluation required under Part III.15.d.iv (comprehensive site compliance evaluation) of this permit, qualified facility personnel shall be identified to inspect designated equipment and areas of the facility at appropriate intervals specified in the plan. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained at the facility.

(5) Employee Training. Employee training programs shall inform personnel responsible for implementing activities identified in the storm water pollution prevention plan or otherwise responsible for storm water management at all levels of responsibility of the components and goals of the storm water pollution prevention plan. Training should address topics such as spill response, good housekeeping and material management practices. A pollution prevention plan shall identify periodic dates for such training.

(6) Recordkeeping and Internal Reporting Procedures. A description of incidents such as spills, or other discharges, along with other information describing the quality and quantity of storm water discharges shall be included in the plan required under this part. Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the plan.

(7) Non-Storm Water Discharges.

(a) The plan shall include a certification that the discharge has been tested or evaluated for the presence of non-storm water discharges. The certification shall include the identification of potential significant sources of non-storm water at the site, a description of the results of any test and/or evaluation for the presence of non-storm water discharges, the evaluation criteria and testing method used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during a test. Certifications shall be signed in accordance with Part III.15.d.vii (signatory requirements) of this permit. Such certification may not be feasible if the facility operating the storm water discharge associated with industrial activity does not have access to an outfall, manhole or other point of access to the ultimate conduit which receives the discharge. In such cases, the source identification section of the storm water pollution plan shall indicate why the certification required by this part was not feasible, along with the identification of potential significant sources of non-storm water at the site.

(b) Except for flows from fire fighting activities, sources of non-storm water listed in subparagraph (a) above (authorized non-storm water discharges) of this permit that are combined with storm water discharges associated with industrial activity must be identified in the plan. The plan shall identify and ensure the implementation of appropriate pollution prevention measures for the non-storm water component(s) of the discharge.

(8) Sediment and Erosion Control. The plan shall identify areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion, and identify structural, vegetative, and/or stabilization measures to be used to limit

erosion.

(9) Management of Runoff. The plan shall contain a narrative consideration of the appropriateness of traditional storm water management practices (practices other than those which control the source of pollutants) used to divert, infiltrate, reuse, or otherwise manage storm water runoff in a manner that reduces pollutants in storm water discharges from the site. The plan shall provide that measures determined to be reasonable and appropriate shall be implemented and maintained. The potential of various sources at the facility to contribute pollutants to storm water discharges associated with industrial activity shall be considered when determining reasonable and appropriate measures. Appropriate measures may include: vegetative swales and practices, reuse of collected storm water (such as for a process or as an irrigation source), inlet controls (such as oil/water separators), snow management activities, infiltration devices, and wet detention/retention devices.

iv. Comprehensive Site Compliance Evaluation. Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the plan, but in no case less than once a year. Such evaluation should include:

(1) Areas contributing to a storm water discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of the permit or whether additional control measures are needed. Structural storm water management measures, sediment and control measures, and other structural pollution prevention measures identified in the plan shall be observed to ensure that they are operating correctly. A visual inspection of

equipment needed to implement the plan, such as spill response equipment, shall be made.

(2) based on the results of the inspection, the description of potential pollutant sources identified in the plan in accordance with Part III.15.d.ii (description of potential pollutant sources) of this permit and pollution prevention measures identified in the plan in accordance with Part III.15.d.iii (measures and controls) of this permit shall be revised as appropriate within two (2) weeks of such inspection and shall provide for implementation of any changes to the plan made in accordance with the plan in a timely manner, but in no case more than twelve (12) weeks from the inspection.

(3) a report summarizing the scope of the inspection, personnel making the inspection, and date(s) of the inspection, major observations relating to the implementation of the storm water pollution prevention plan, and actions taken in accordance with Part III.15.d.iv.2 above shall be made and retained as part of the Storm Water Pollution Prevention Plan for at least three years. The report shall be signed in accordance with Part III.15.d.vii (signatory requirements) of this permit.

v. <u>Consistency with other plans</u>. Storm water management programs may reflect requirements for Spill Prevention Control and Countermeasure (SPCC) plans under section 311 of the Clean Water Act (CWA) or Best Management Practices (BMP) Programs otherwise required by an NPDES permit for the facility as long as such requirement is incorporated into the storm water pollution prevention plan.

vi. <u>Retention of Records.</u> The permittee shall retain the pollution prevention plan developed for at least one year after coverage under the permit terminates. The permittee shall retain records of all monitoring information, keep copies of all reports required by this permit, and records of all data used to complete the application of this permit for at least one year after coverage for this permit is terminated. This period may be explicitly extended by request of the Director at any time.

vii. <u>Signatory Requirements.</u> Storm water pollution prevention plans, reports, certifications or information submitted to the Director or the operator of a large or medium municipal separate storm sewer system, and any other reports required to be maintained by the permittee, shall be signed and certified.

(1) All applications shall be signed as follows:

(a) For a corporation: by a responsible corporate officer. For purposes of this section, a responsible corporate officer means:

(i) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or

(ii) the manager or one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(b) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

(c) For a municipality, State, Federal or other public agency: By either a principal executive or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:

(i) the chief executive officer of the agency; or

(ii) a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

(d) All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(i) the authorization is made n writing by a person described above and submitted to the Director;

(ii) the authorization specifies either an individual or a person having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility, or position of equivalent responsibility for environmental matters for the company. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and

e. Changes to authorization. If an authorization under this subpart is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the above requirement must be submitted to the Director prior to or together with any reports, information, or applications to be signed by an authorized representative.

i. <u>Special requirements for storm water discharges associated with industrial activity from facilities subject to SARA Title III, Section 313 requirements</u>. In addition to the requirements of Parts III.15.d.i through 15.d.iv and other applicable conditions of this permit, storm water pollution prevention plans for facilities subject to reporting requirements under SARA Title III, Section 313 for chemicals which are classified as "Section 313 water priority chemicals", shall describe and ensure the implementation of practices which are necessary to provide for conformance with the following guidelines.

(1) in areas where Section 313 water priority chemicals are stored, processed, or otherwise handled, appropriate containment, drainage control and/or diversionary structures shall be provided. At a minimum, one of the following preventive systems or its equivalent shall be used:

(a) Curbing, culverting, gutters, sewers, or other forms of drainage control to prevent or minimize the potential for storm water run-on to come into contact with significant sources of pollutants; and

(b) Roofs, covers, or other forms of appropriate protection to prevent storage piles from exposure to storm water and wind.

(2) In addition to the minimum standards listed under Part III.15.e.i.1 above (special requirements for storm water discharges associated with industrial activity from facilities subject to SARA Title III, Section 313 requirements), the storm water pollution prevention plan shall include a complete discussion of measures taken to conform with the following guidelines, as applicable, and other effective storm water pollution prevention guidelines:

(a) <u>Liquid storage areas where storm water comes into contact with any equipment, tank, container, or other vessel used for Section 313 water priority chemicals</u>.

(i) no tank or container shall be used for the storage of a Section 313 water priority chemical unless its material and construction are compatible with the material being stored and conditions of storage such as pressure and temperature, etc.

(ii) liquid storage areas for Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 materials. Appropriate measures to minimize discharges of Section 313 chemicals may include secondary containment provided for at least the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation, a strong spill contingency and integrity testing plan, and/or other equivalent measures.

(b) <u>material storage areas for Section 313 water priority chemicals other than liquids.</u> Material storage areas for Section 313 water priority chemicals other than liquids which are subject to runoff, leaching, or wind blowing shall incorporate drainage or other control features which will minimize the discharge of Section 313 water priority chemicals by reducing storm water contact with Section 313 water priority chemicals.

(c) <u>truck and rail car loading and unloading areas for Section 313 water priority chemicals</u>. Truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 water priority chemicals. Appropriate measures to minimize discharges of Section 313 chemicals may include: the placement and maintenance of drip pans (including the proper disposal of materials collected in the drip pans) where spillage may occur (such as hose connections, hose reels and filler nozzles) for use when making and breaking hose connections; a strong spill contingency and integrity testing plan; and/or other equivalent measures.

(d) areas where Section 313 water priority chemicals are transferred, processed, or otherwise handled. Processing equipment and materials handling equipment shall be operated so as to minimize discharges of Section 313 water priority chemicals. Materials used in piping and equipment shall be compatible with the substances handled. Drainage from process and materials handling areas shall minimize storm water contact with Section 313 water priority chemicals. Additional protection such as covers or guards to prevent exposure to wind, spraying or releases from pressure relief vents from causing a discharge of Section 313 water priority chemicals to the drainage system, and overhangs or door skirts to enclose trailer ends at truck loading/unloading docks shall be provided as appropriate. Visual inspections or leak tests shall be provided for overhead piping conveying Section 313 water priority chemicals without secondary containment.

(e) discharges from areas covered in paragraphs (a), (b), (c), or (d) (above).

(i) drainage from areas covered by paragraphs (a), (b), (c), or (d) of this part shall be restrained by valves or other positive means to prevent the discharge of a spill or other excessive leakage of Section 313 water priority chemicals. Where containment units are employed, such units may be emptied by pumps or ejectors; however, these shall be manually operated.

(ii) flapper-type drain valves shall not be used to drain containment areas. Valves used for the drainage of containment areas should, as far as is practical, be of manual, open-and-closed design.

(iii) if facility drainage is not engineered as above, the final discharge of all in-facility storm sewers shall be equipped with a diversion system that could, in the event of an uncontrolled spill of Section 313 water priority chemicals, return the spilled material to the facility.

(iv) Records shall be kept of the frequency and estimated volume (in gallons) of discharges from containment areas.

(f) facility site runoff other than from areas covered by (a), (b), (c), or (d). Other areas of the facility (those not addressed in paragraphs (a), (b), (c), or (d)) from which runoff which may contain Section 313 water priority chemicals could cause a discharge shall incorporate the necessary drainage or other control features to prevent discharge of spilled or improperly disposed material and ensure the mitigation of pollutants in runoff or leachate.

(g) <u>preventive maintenance and housekeeping</u>. All areas of the facility shall be inspected at specific intervals for leaks or conditions that could lead to discharges of Section 313 water priority chemicals or direct contact of storm water with raw materials, intermediate materials, waste materials or products. In particular, facility piping, pumps, storage tanks and bins, pressure vessels, process and material handling equipment, and material bulk storage areas shall be examined for any conditions or failures which could cause a discharge. Inspections shall include an examination for leaks, wind blowing, corrosion, support or foundation failure, or other forms of deterioration or noncontainment. Inspection intervals shall be specified in the plan and shall be based on design and operational experience. Different areas may require different inspection intervals. Where a leak or other condition is discovered which may result in significant releases of Section 313 water priority chemicals to the drainage system, corrective action shall be immediately taken or the unit or process shut down until corrective action can be taken. When a leak or noncontainment of a Section 313 water priority chemical has occurred, contaminated soil, debris, or other material must be promptly removed and disposed in accordance with Federal, State, and local requirements and as described in the plan.

(h) <u>facility security</u>. Facilities shall have the necessary security systems to prevent accidental or intentional entry which could cause a discharge. Security systems described in the plan shall address fencing, lighting, vehicular traffic control, and securing of equipment and buildings.

(i) <u>training</u>. Facility employees and contractor personnel that work in areas where SARA Title III, Section 313 water priority chemicals are used or stored shall be trained in and informed of preventive measures at the facility. Employee training shall be conducted at intervals specified in the plan, but not less than once per year, in matters of pollution control laws and regulations, the storm water pollution prevention plans, and the particular features of the facility and its operation which are designed to minimize discharges of Section 313 water priority chemicals. The plan shall designate a person who is accountable for spill prevention at the facility and who will set up the necessary spill emergency procedures and reporting requirements so that spills and emergency releases of Section 313 water priority chemicals can be isolated and contained before a discharge of a Section 313 water priority chemical can occur. Contractor or temporary personnel shall be informed of plant operation and design features in order to prevent discharges or spills from occurring.

(ii) <u>Engineering certification</u>. The storm water pollution prevention plan for facilities subject to SARA Title III, Section 313 for chemicals which are classified as "Section 313 water priority chemicals" shall be reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. A Registered Professional Engineer shall recertify the plan every three (3) years thereafter or as soon as practicable after significant modifications are made to the facility. By means of these certifications the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the storm water pollution prevention plan has been prepared in accordance with good engineering practices. Such certifications shall in no way relieve the owner or operator of a facility covered by the plan of their duty to prepare and fully implement such plan.

PART IV —
SECTION A — DEFINITIONS

All definitions contained in Section 502 of the Clean Water Act shall apply to this permit and are incorporated herein by reference. Additional definitions of words or phrases used in this permit are as follows:

1. "Act" means the Clean Water Act, Public Law 95-217(33. U.S.C. 1251 et seq.) as amended.
2. "Administrator" means the Administrator of the U.S. Environmental Protection Agency.
3. "Applicable effluent standards and limitations" means all State and Federal effluent standards and limitations to which a discharge is subject under the Act, including, but not limited to, effluent limitations, standards of performance, toxic effluent standards and prohibitions, and pretreatment standards.
4. "Applicable water quality standards" means all water quality standards to which a discharge is subject under the federal Clean Water Act and which have been (a) approved or permitted to remain in effect by the Administrator following submission to the Administrator pursuant to Section 303(a) of the Act, or (b) promulgated by the Director pursuant to Section 303(b) or 303(c) of the Act, and standards promulgated under regulation No. 2, as amended, (regulation establishing water quality standards for surface waters of the State of Arkansas).
5. "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.
6. "Daily Discharge" means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in terms of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the sampling day. For pollutants with limitations expressed in other units of measurement, the "daily discharge" is calculated as the average measurement of the pollutant over the sampling day. "Daily discharge" determination of concentration made using a composite sample shall be the concentration of the composite sample. When grab samples are used, the "daily discharge" determination of concentration shall be the arithmetic average (weighted by flow value) of all the samples collected during that sampling day.
7. "Daily Average" (also known as monthly average) discharge limitations means the highest allowable average of "daily discharge(s)" over a calendar month, calculated as the sum of all "daily discharge(s)" measured during a calendar month divided by the number of "daily discharge(s)" measured during that month. When the permit establishes daily average concentration effluent limitations or conditions, the daily average concentration means the arithmetic average (weighted by flow) of all "daily discharge(s)" of concentration determined during the calendar month where C = daily concentration, F = daily flow and n = number of daily samples; daily average discharge =

$$\frac{C1F1 + C2F2 + \ldots CnFn}{F1 + F2 + \ldots + Fn}$$

8. "Daily Maximum" discharge limitation means the highest allowable "daily discharge" during the calendar month.
9. "Department" means the Arkansas Department of Pollution Control and Ecology (ADPCE).
10. "Director" means the Administrator of the U.S. Environmental Protection Agency and/or the Director of the Arkansas Department of Pollution Control and Ecology.
11. "Grab sample" means an individual sample collected in less than 15 minutes in conjunction with an instantaneous flow measurement.
12. "Industrial User" means a nondomestic discharger, as identified in 40 CFR 403, introducing pollutants to a publicly-owned treatment works.
13. "National Pollutant Discharge Elimination System" means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under sections 307, 402, 318, and 405 of the Clean Water Act.
14. "POTW" means a Publicly Owned Treatment Works.
15. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in productions.
16. "ADPCE" means the Arkansas Department of Pollution Control and Ecology.
17. "Sewage sludge" means the solids, residues, and precipitate separated from or created in sewage by the unit processes of a publicly-owned treatment works. Sewage as used in this definition means any wastes, including wastes from humans, households, commercial establishments, industries, and storm water runoff, that are discharged to or otherwise enter a publicly-owned treatment works.
18. "7-day average" discharge limitation, other than for fecal coliform bacteria, is the highest allowable arithmetic means of the values for all effluent samples collected during the calendar week. The 7-day average for fecal coliform bacteria is the geometric mean of the values of all effluent samples collected during the calendar week. The DMR should report the highest 7-day average obtained during the calendar month. For reporting purposes, the 7-day average values should be reported as occurring in the month in which the Saturday of the calendar week falls in.
19. "30-day average", other than for fecal coliform bacteria, is the arithmetic mean of the daily values for all effluent samples collected during a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month. The 30-day average for fecal coliform bacteria is the geometric mean of the values for all effluent samples collected during a calendar month.
20. "24-hour composite sample" consists of a minimum of 12 effluent portions collected at equal time intervals over the 24-hour period and combined proportional to flow or a sample collected at frequent intervals porportional to flow over the 24-hour period.
21. "12-hour composite sample" consists of 12 effluent portions collected no closer together than one hour and composited according to flow. The daily sampling intervals shall include the highest flow periods.
22. "6-hour composite sample" consists of six effluent portions collected no closer together than one hour (with the first portion collected no earlier than 10:00 a.m.) and composited according to flow.
23. "3-hour composite sample" consists of three effluent portions collected no closer together than one hour (with the first portion collected no earlier than 10:00 a.m.) and composited according to flow.
24. "Treatment works" means any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage and industrial wastes, of a liquid nature to implement section 201 of the Act, or necessary to recycle reuse water at the most economic cost over the estimated life of the works, including intercepting sewers, sewage collection systems, pumping, power and other equipment, and alterations thereof; elements essential to provide a reliable recycled supply such as standby treatment units and clear well facilities, and any works, including site acquisition of the land that will be an integral part of the treatment process or is used for ultimate disposal of residues resulting from such treatment.
25. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. Any upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, lack of preventive maintenance, or careless or improper operations.
26. For "fecal coliform bacteria", a sample consists of one effluent grab portion collected during a 24-hour period at peak loads.
27. "Dissolved oxygen", shall be defined as follows:
    a. When limited in the permit as a monthly minimum, shall mean the lowest acceptable monthly average value, determined by averaging all samples taken during the calendar month;
    b. When limited in the permit as an instantaneous minimum value, shall mean that no value measured during the reporting period may fall below the stated value.
28. The term "MGD" shall mean million gallons per day.
29. The term "mg/l" shall mean milligrams per liter or parts per million (ppm)
30. The term "μg/l" shall mean micrograms per liter or parts per billion (ppb)

Attachment C

U.S. Fish and Wildlife Service Correspondence:

Letter from Dr. Gary E. Tucker, FTN Associates, Ltd., to Marge Harney, U.S. Fish and Wildlife Service, dated August 4, 1997

Letter from Dr. Gary E. Tucker, FTN Associates, Ltd., to Margaret Harney, U.S. Fish and Wildlife Service, dated September 2, 1999

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AUG 6 1997

U.S. FISH & WILDLIFE SERV...
VICKSBURG, MS

ftn Associates Ltd.
water resources / environmental consultants

August 4, 1997

Ms. Marge Harney
US Fish and Wildlife Service
2524 S Frontage Rd, Suite B
Vicksburg, MS 39180-5269

RE: Federally Listed Species for Industrial Facility, Pope County, Arkansas
FTN No. 6045-060

Dear Ms. Harney:

FTN Associates, Ltd. (FTN) is conducting reviews of potential environmental issues at an industrial client's facilities in Arkansas. The legal description for a facility in Pope County is SW¼ SW¼ of Section 27 and S½ of SE¼ of Section 28, Township 8 North, Range 21 West. Also, the facility's boundary extends barely into the NE¼ of Section 33 and NW¼ of Section 34, Township 8 North, Range 21 West.

With this letter, we are requesting from you a list of federally listed species having a potential for occurrence at the Pope County facility. From our review of pertinent literature, FTN has identified five animal species having geographic ranges that would include Pope County, at least on a historical basis. These species include: bald eagle, red-cockaded woodpecker, interior least tern, Bachman's warbler, and Florida panther. Of these five species, however, we have found no solid evidence that either live organisms or suitable habitat for any of the five animal species is expected within the confines of the facility, with the possible exception of occasional stray bald eagle individuals flying within the boundaries of the facility on rare occasions. We have identified no plant species having a potential for occurrence within the facility's boundaries. We look forward to receiving a written response from you relative to our preliminary assessment about these species.

If you have questions or need additional information, please call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Gary E. Tucker

Gary E. Tucker, PhD
Project Scientist

N:\WP_FILES\6045-060\L-HARNEY.WP\JBW

No federally listed endangered, threatened or candidate species present

Margaret Harney

Environmental Coordinator
U.S. Fish and Wildlife Service

Log# 97-762

Aug 7, '97
Date

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738
Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

6045-060
Entergy

ftn Associates Ltd.
water resources / environmental consultants

RECEIVED

SEP 03 1999

ARK FIELD OFFICE

September 2, 1999

Ms. Margaret Harney
US Fish and Wildlife Service
1500 Museum Road
Suite 105
Conway, AR 73032

RE: Request for Information Regarding Federally Listed Threatened and Endangered Species, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Ms. Harney:

The purpose of this letter is to follow up on our phone conversation of August 26, 1999 regarding Entergy's Arkansas Nuclear One (ANO) facility permitting issues. You will recall from our conversation that I said we soon would be providing a request for information regarding federally listed threatened and endangered species having a potential for occurrence within ANO's existing transmission line corridors. The enclosed map provides you with approximate corridor locations.

Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 under the authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. Please note that the application solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For

Gary E. Tucker, PhD, PWS
Environmental Scientist

CC: Rick Buckley - Entergy

Enclosure

P:\WP_FILES\6045-061\L-MARGE.WPD\BMW

No federally listed endangered, threatened or candidate species present

Deborah W Rychly
Environmental Coordinator
U.S. Fish and Wildlife Service

Log# 99-491

10-1-99
Date

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738

2949 Point Circle • Suite 1 • Fayetteville, AR 72704
(501) 571-3334 • Fax (501) 571-3338

Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

6045-061 ANO Relicensing

Attachment D

Arkansas Natural Heritage Commission Correspondence:

Letter from Cindy Osborne, Arkansas Natural Heritage Commission, to Dr. Gary E. Tucker, FTN Associates, Ltd., dated August 19, 1997.

Letter from Cindy Osborne, ANHC to Gary E. Tucker, FTN dated September 29, 1999 (Client Contact Report dated October 4, 1999)

Personal communication between Gary E. Tucker and Cindy Osborne, ANHC, dated October 13, 1999

ARKANSAS NATURAL HERITAGE COMMISSION
1500 TOWER BUILDING
323 CENTER STREET
LITTLE ROCK, ARKANSAS 72201

Harold K. Grimmett
Director

Mike Huckabee
Governor

Date: August 19, 1997
Subject: Elements of Special Concern
Industrial Facility, Pope Co.
FTN No. 6045-060
ANHC No.: P-CF..-97-059

Dr. Gary Tucker
FTN Associates Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

Dear Dr. Tucker:

Staff members of the Arkansas Natural Heritage Commission have reviewed our files for records indicating the occurrence of rare plants and animals, outstanding natural communities or other elements of special concern within or near the industrial site in Sections 27, 28, 33, and 34 of Township 8 North, Range 21 West in Pope County, Arkansas. We find no records at the present time.

A Pope County Element List has been enclosed for your reference. Represented on this list are elements for which we have records in our database in this county. A "✓" has been placed by those elements falling on the same topographic quadrangle (Russellville West 7.5') as the project site. A legend is enclosed to help you interpret the codes on the list.

Please keep in mind that the project area may contain important natural features of which we are unaware. Staff members of the Arkansas Natural Heritage Commission have not conducted a field survey of the project site. Our review is based on data available to the program at the time of the request. It should not be regarded as a final statement on the elements or areas under consideration, nor should it be substituted for on-site surveys required for environmental assessments. Because our files are updated constantly, you may want to check with us again at a later time.

Thank you for consulting us. It has been a pleasure to work with you on this study.

Sincerely,

Cindy Osborne

Cindy Osborne
Data Manager

Enclosure: Legend
Pope County Element List, annotated
Invoice

.9 AUG 1997

ARKANSAS NATURAL HERITAGE COMMISSION
DEPARTMENT OF ARKANSAS HERITAGE
INVENTORY RESEARCH PROGRAM
ELEMENTS OF SPECIAL CONCERN
POPE COUNTY

ELEMENT NAME	FEDERAL STATUS	STATE STATUS	GLOBAL RANK	STATE RANK
** Animals				
* Invertebrates				
CAMBARUS CAUSEYI, A CRAYFISH	-	INV	G1	S1
LIRCEUS BICUSPIDATUS, AN ISOPOD	-	INV	G3Q	S3
* Vertebrates				
CORYNORHINUS RAFINESQUII, RAFINESQUE'S BIG-EARED BAT	-	INV	G3G4	S2
EGRETTA CAERULEA, LITTLE BLUE HERON	-	INV	G5	S2
HYLA AVIVOCA, BIRD-VOICED TREEFROG	-	INV	G5	S2?
MYOTIS GRISESCENS, GRAY MYOTIS	LE	INV	G2G3	S2
PERCINA NASUTA, LONGNOSE DARTER	3C	INV	G3	S2
PODILYMBUS PODICEPS, PIED-BILLED GREBE	-	INV	G5	S2?
PSEUDACRIS STRECKERI STRECKERI, STRECKER'S CHORUS FROG	-	INV	G5T4	S1?
RANA AREOLATA CIRCULOSA, NORTHERN CRAWFISH FROG	-	INV	G4T4	S1?
REGINA SEPTEMVITTATA, QUEEN SNAKE	-	INV	G5	S1?
SPEA BOMBIFRONS, PLAINS SPADEFOOT	-	INV	G5	S1
STERNA ANTILLARUM ATHALASSOS, INTERIOR LEAST TERN	LE	INV	G4T2Q	S2
** Plants				
* Vascular Plants				
CAREX CAREYANA, CAREY'S SEDGE	-	INV	G5	S2
CAREX COMMUNIS, FIBROUS-ROOT SEDGE	-	INV	G5	S2S3
CASTANEA PUMILA VAR. OZARKENSIS, OZARK CHINQUAPIN	-	INV	G5T3	S3S4
CAULOPHYLLUM THALICTROIDES, BLUE COHOSH	-	INV	G5	S2
DELPHINIUM NEWTONIANUM, MOORE'S LARKSPUR	3C	INV	G3	S3
DRABA APRICA, OPEN-GROUND WHITLOW-GRASS	3C	ST	G3	S2
ERIOCAULON KORNICKIANUM, SMALL-HEADED PIPEWORT	-	SE	G2G3	S2
EUPHORBIA HEXAGONA, SIX-ANGLE SPURGE	-	INV	G5	S2
HEUCHERA VILLOSA VAR. ARKANSANA, ARKANSAS ALUMROOT	3C	INV	G5T3Q	S3
HYDROCOTYLE AMERICANA, AMERICAN WATER-PENNYWORT	-	INV	G5	SH
MALUS CORONARIA, SWEET CRAB-APPLE	-	INV	G5	S2S3
MIMULUS FLORIBUNDUS, FLORIFEROUS MONKEYFLOWER	-	INV	G5	S2S3
NEVIUSIA ALABAMENSIS, ALABAMA SNOW WREATH	-	ST	G2	S1S2
OSMUNDA CLAYTONIANA, INTERRUPTED FERN	-	ST	G5	S1
PHILADELPHUS HIRSUTUS, A MOCK ORANGE	-	INV	G5	S2S3
PODOSTEMUM CERATOPHYLLUM, THREADFOOT	-	INV	G5	S3
SANICULA SMALLII, SMALL'S SANICLE	-	INV	G5	S3

ELEMENT NAME	FEDERAL STATUS	STATE STATUS	GLOBAL RANK	STATE RANK
<u>SELAGINELLA</u> <u>ARENICOLA</u> SSP. <u>RIDDELLII</u>, RIDDELL'S SPIKE MOSS	-	INV	G4T4	S3
<u>SILENE</u> <u>OVATA</u>, OVATE-LEAF CATCHFLY	-	ST	G3	S2
<u>TRADESCANTIA</u> <u>OZARKANA</u>, OZARK SPIDERWORT	-	INV	G2G3	S3
<u>TRADESCANTIA</u> <u>SUBASPERA</u>, A SPIDERWORT	-	INV	G5	S1S3
<u>TRICHOMANES</u> <u>PETERSII</u>, DWARF FILMY-FERN	-	ST	G4G5	S2
** Natural Communities				
MESIC OAK-HICKORY FOREST	-	INV	-	S4
OVERCUP OAK FOREST	-	INV	-	S2
RIVER FRONT FOREST	-	INV	-	S3
SANDSTONE GLADE/OUTCROP	-	INV	-	S4
TALLGRASS PRAIRIE	-	INV	-	S2
UPLAND STREAM-OZARK MOUNTAINS	-	INV	-	-
** Other				
COLONIAL NESTING SITE, COLONIAL WATER BIRDS	-	INV	-	-
GEOLOGICAL FEATURE	-	INV	-	-

LEGEND

FEDERAL STATUS CODES

C1 = Category 1; the U.S. Fish and Wildlife Service states it currently has substantial information on hand that supports listing these species as threatened or endangered.

C2 = Category 2; the U.S. Fish and Wildlife Service states that further biological research and field study will be necessary in order to determine if these species should be listed as threatened or endangered (AS OF FEBRUARY 28, 1996 THE U.S. FISH & WILDLIFE SERVICE WILL NO LONGER MAINTAIN A LIST OF CATEGORY 2 SPECIES)

3C = These species have been reviewed by the U.S. Fish and Wildlife Service and the determination has been made that special designation is not warranted.

3B = Names that, on the basis of current taxonomic understanding (usually as represented in published revisions and monographs) do not represent distinct taxa meeting the Endangered Species Act's definition of "species." Such supposed taxa could be reevaluated in the future on the basis of new information.

LE = Listed Endangered; the U.S. Fish and Wildlife Service has listed these species as endangered.

LT = Listed Threatened; the U.S. Fish and Wildlife Service has listed these species as threatened.

LELT = Listed Endangered and Threatened; the U.S. Fish and Wildlife Services has listed these species as endangered and threatened in different parts of the breeding range.

PE = Proposed Endangered; the U.S. Fish and Wildlife Service has proposed these species for listing as endangered.

PT = Proposed Threatened; the U.S. Fish and Wildlife Service has proposed these species for listing as threatened.

T/SA = E/SA Threatened (or Endangered) because of similarity of appearance.

STATE STATUS CODES

INV = Inventory Element; The Arkansas Natural Heritage Commission is currently conducting inventory work on these elements to determine their status in the state. These elements may include outstanding examples of Natural Communities, colonial nesting sites, outstanding scenic and geologic features as well as plants and animals which, according to current information, may be rare, peripheral, or of an undetermined status in the state.

SE = State Endangered; The Arkansas Natural Heritage Commission applies this term to native taxa which are in danger of being extirpated from the state.

ST = State Threatened; The Arkansas Natural Heritage Commission applies this term to native taxa which are believed likely to become endangered in Arkansas in the foreseeable future, based on current inventory information.

DEFINITION OF RANKS

Global Ranks

G1 = Critically imperiled globally because of extreme rarity (5 or fewer occurrences or very few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

G2 = Imperiled globally because of rarity (6-20 occurrences or few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

ARKANSAS NATURAL HERITAGE COMMISSION
1500 TOWER BUILDING
323 CENTER STREET
LITTLE ROCK, ARKANSAS 72201

Harold K. Grimmett
Director

Mike Huckabee
Governor

Date: September 29, 1999
Subject: Elements of Special Concern
Existing Transmission Line Corridors
Arkansas Nuclear One
ANHC No.: P-CF..-99-079

Dr. Gary Tucker
FTN Associates, Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

Dear Dr. Tucker:

Staff members of the Arkansas Natural Heritage Commission have reviewed our files for records indicating the occurrence of rare plants and animals, outstanding natural communities, natural or scenic rivers, or other elements of special concern within the footprint of Arkansas Nuclear One's existing transmission line corridors. The results of this search are presented on your map and the enclosed data print-out. A legend is provided to help you interpret the codes on the print-out.

Our records indicate the potential occurrence of three species of state concern within the transmission line corridor: a mock orange (Philadelphus hirsutus), Ozark chinquapin (Castanea pumila var. ozarkensis), and Bachman's sparrow (Aimophila aestivalis). Mock orange is an uncommon species in the state where its distribution is disjunct from its eastern range. It is known principally from the Ozark region in Arkansas. Ozark chinquapin can still be found in relatively large numbers, but is of concern because of decline due to chestnut blight. Bachman's sparrow is a regular summer resident and can be locally common in successional pine habitat. It is of interest because of rangewide declines.

Three other locations along the transmission corridors are of interest to this agency: Illinois Bayou, Cadron Creek, and Goose Pond Natural Area. Portions of the Illinois Bayou and Cadron Creek are listed on the state Registry of Natural and Scenic Rivers and are considered "Extraordinary Resource Waters" by the Arkansas Department of Environmental Quality. Transmission line corridors cross each of these streams within the designated portions one time. The transmission lines also cross a corner of Goose Pond Natural Area. The Arkansas Natural Heritage Commission holds a conservation easement on this area. It is contained within the Ed Gordon/Point Remove Wildlife Managment Area managed by the Arkansas Game and Fish Commission. A boundary map of the Natural Area boundaries is provided.

Yell, Logan, Johnson, Pope, Conway, Faulkner, and Pulaski County Element Lists are enclosed for your reference. Represented on these lists are elements for which we have records in these counties. You may refer to the enclosed legend for help interpreting the codes on these lists.

Please keep in mind that the project area may contain important natural features of which we are unaware. Staff members of the Arkansas Natural Heritage Commission have not conducted a field survey of the transmission line corridors. Our review is based on data available to the program at the time of the request. It should not be regarded as a final statement on the elements or areas under consideration, nor should it be substituted for on-site surveys required for environmental assessments. Because our files are updated constantly, you may want to check with us again at a later time.

Thank you for consulting us. It has been a pleasure to work with you on this study.

Sincerely,

Cindy Osborne

Cindy Osborne
Data Manager

Enclosures: Information Sheet and Legend
Your map, enriched
Data Print-out
Information Sheet on State Natural and Scenic Rivers
Boundary Map - Goose Pond Natural Area
7 County Element Lists - Yell, Logan, Johnson, Pope, Conway, Faulkner, Pulaski
Invoice

CLIENT CONTACT REPORT

Project/Client:	ANO 99 Support	**Date/Time:**	October 4, 1999
Topic:		**Phone:**	
Contact:	Cindy Osborne	**By:**	Gary E. Tucker
Firm:	Arkansas Natural Heritage Comm.	**Date:**	
Address:	1500 Tower Bldg., 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

Today we received a letter from Ms. Osborne, Arkansas Natural Heritage Commission (ANHC), dated September 29, 1999 and addressed to me, in which she included (1) a map of element occurrences, (2) data printout, (3) information sheet on state natural and scenic rivers, (4) boundary map of a state natural area, and (5) county element lists for Yell, Logan, Johnson, Pope, Conway, Faulkner, and Pulaski counties.

After a re-evaluation of the information requested from her — and a full evaluation of information received from her, it was determined that (1) there are no species element occurrence records related to the ANO Unit 1 500/161 kV transmission lines. Each of the species element occurrence records mentioned in her letter is associated with the ANO Unit 2 500 kV line from ANO to Mayflower and Mablevale. The status of Illinois Bayou as listed stream on the Registry of Natural and Scenic Rivers and as an extraordinary resource water, as designated by Arkansas Department of Environmental Quality, is indicated in the letter. Each of these designations was applied to Illinois Bayou after installation of the transmission lines, and because the request for relicensing of ANO Unit 1 involves no new construction of transmission lines, these designations represent moot issues. The important conclusion to derive from Ms. Osborne's letter is that there are NO KNOWN LOCATIONS for species of concern which are tracked by ANHC for ANO Unit 1, which is the subject of the relicensing effort.

	Routing	Reviewed	Comments/Action
1	BMW	RW	
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other**

CLIENT CONTACT REPORT

Project/Client:	ANO Relicensing	**Date/Time:**	October 13, 1999
Topic:		**Phone:**	
Contact:	Cindy Osborne	**By:**	Gary E. Tucker
Firm:	Arkansas Natural Heritage Comm.	**Date:**	
Address:	1500 Tower Bldg., 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

I contacted Ms. Osborne to follow up on her August 19, 1997 letter addressed to me and regarding elements of special concern at the Arkansas Nuclear One (ANO) facility. She indicated that (1) there have been no additional records pertaining to the ANO site which have been added to their database since August 1997, and (2) Arkansas Natural Heritage Commission has no regulatory authority to require a landowner to conduct a field survey on the owner's property. I told her that the ANO site represents an industrial site which has experienced major alteration of its original vegetation cover, and the chances of finding occurrences of elements of special concern would appear to be remote and probably not justify a formal survey. She said she could agree with that viewpoint.

	Routing	**Reviewed**	**Comments/Action**
1	BMW		
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other**__________

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Attachment E

Arkansas Game and Fish Commission Correspondence:

Letter from Mr. Gary E. Tucker, FTN Associates to Mr. Craig Uyeda, Arkansas Game and Fish Commission, dated September 2, 1999

ftn Associates Ltd.
water resources / environmental consultants

RECEIVED
SEP 07 1999
RIVER BASINS

September 2, 1999

Mr. Craig Uyeda, River Basins
Arkansas Game and Fish Commission
2 Natural Resources Drive
Little Rock, AR 72205

RE: Request for Information on Federally Listed Threatened and Endangered Species and Other Wildlife Species Issues, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Mr. Uyeda:

The purpose of this letter is to follow up on our phone conversation of August 26, 1999 regarding Entergy's Arkansas Nuclear One (ANO) facility permitting issues. You will recall from our conversation that I said we soon would be providing a request for information regarding the potential occurrence of federally listed threatened and endangered species and other wildlife species issues within ANO's existing transmission line corridors. The enclosed map provides you with approximate corridor locations.

Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 by authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. Please note that the application solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For

Gary E. Tucker, PhD, PWS
Environmental Scientist

Enclosure

CC: Rick Buckley - Entergy

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ARKANSAS GAME & FISH COMMISSION
Our records indicate no federally listed endangered and/or threatened fish and wildlife species occur in the project area.

Date: 10-12-99

Signed: Robert K Leonard

Attachment F

State Historic Preservation Office Correspondence:

Letter from Cathy Buford Slater, State Historic Preservation Officer, to Dr. Gary E. Tucker, FTN Associates, Ltd., dated March 30, 1998

Personal communication between George McCluskey State Historic Preservation Office (SHPO) and Dr. Gary E. Tucker, FTN Associates, Ltd., on April 1, 1998

Personal communication between George McCluskey State Historic Preservation Office (SHPO) and Dr. Gary E. Tucker, FTN Associates, Ltd., on April 2, 1998

Letter from Gary E. Tucker, FTN to George McCluskey State Historic Preservation Office, dated September 2, 1999

ARKANSAS
HISTORIC
PRESERVATION
PROGRAM

March 30, 1998

Dr. Gary E. Tucker
Environmental Scientist
FTN Associates, Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

RE: Pope County - Russellville
Section 106 Review - NRC
Historic Properties Issues at Arkansas Nuclear
One Plant Site Near Russellville, Arkansas

Dear Dr. Tucker:

This letter is written in response to your inquiry regarding properties of archeological, historical, or architectural significance within the property boundary of the Arkansas Nuclear One (ANO) plant site near Russellville, Arkansas.

The staff of the Arkansas Historic Preservation Program has reviewed the records that pertain to the area in question. The staff has reported that five archeological sites (3PP62, 3PP63, 3PP65, 3PP66, and the May Cemetery) are located within the ANO property boundary. All five of these sites are potentially eligible for inclusion in the National Register of Historic Places. Other unknown archeological sites may also be present. Therefore, a master plan should consider potential impacts on historic properties that may result from the development or expansion of the Arkansas Nuclear One facility. A cultural resources survey to identify and evaluate historic properties, pursuant to Section 106 of the National Historic Preservation Act, may also be necessary.

Thank you for your interest and concern for the cultural heritage of Arkansas. If you have any questions, please contact George McCluskey of my staff at (501) 324-9880.

Sincerely,

Cathy Slater

Cathy Buford Slater
State Historic Preservation Officer

REC'D APR - 1 1998

CBS:GM

cc: Arkansas Archeological Survey

1500 Tower Building • 323 Center • Little Rock, Arkansas 72201 • Phone (501) 324-9880
Fax (501) 324-9184 • TDD (501) 324-9811
A Division of the Department of Arkansas Heritage

L045-060 ANO EIS

CLIENT CONTACT REPORT

Project/Client:	ANO EIS	**Date/Time:**	4/1/98
Topic:		**Phone:**	
Contact:	George McCluskey	**By:**	GET
Firm:	SHPO	**Date:**	
Address:		**Referral:**	
City State Zip:			

Remarks:

Talked w/ George about letter from SHPO concerning ANO cultural resources issues. No systematic survey has been done in vicinity of plant. Pertinent cultural resources legislation dates from 1966 but state office really didn't get functional until around 1970. There was a limited amount of work done at time Lake Dardanelle was constructed. George said the May Cemetery probably has headstones and a fence and would be known to local people. The remaining sites are archeological and not be evident to casual observer. Little is known about any of sites and little indication as to whether they would be worthy of National Registert. SHPO does know that Cherokee sites were probably extensive in area but most now under water. He said map we sent was good enough that he was able to determine that none of archeological sites are close enough to existing facilities to be of concern. Ongoing "maintenance" is exempt from SHPO concerns. In event that ANO intends to erect new facilities or has major ground disturbing activities, they would need to contact SHPO for consultation. Normally it takes a permit to trigger SHPO involvement, i.e., something from Nuclear Regulatory Commission or Corps. As a part of re-licensing effort, he said Entergy "might want to write a letter to SHPO specifically indicating its intent to pursue re-licensing but without any new construction". In the event of future construction, they can write a letter and indicate where ground disturbing activities would be. SHPO could probably make its assessment from information provided. In this instance, George said there is no reason for concern. Section 106 refers to the regs that trigger SHPO review process....in event of permit application.

	Routing	Reviewed	Comments/Action
1	BMW	[initials]	
2	DEF	[initials]	
3			
4			
5			

Disposition: Discard File 6045-060 ANO EIS

For Filing Only: ☐ Contact/Correspondence ☐ Contract ☐ Proposal ☐ Other

CLIENT CONTACT REPORT

Project/Client:	ANO 99 Support	**Date/Time:**	April 2, 1998
Topic:		**Phone:**	
Contact:	George McCluskey	**By:**	Gary E. Tucker
Firm:	State Historic Preservation Office	**Date:**	
Address:	1500 Tower Building, 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

Yesterday we received a letter from Cathy Slater, State Historic Preservation Officer (SHPO), in response to our query regarding the presence of potential cultural resources issues within the property boundary of Arkansas Nuclear One (ANO) facility. The letter indicated that a "cultural resources survey to identify and evaluate historic properties, pursuant to Section 106 of the National Historic Preservation Act, may also be necessary." I talked with George McCluskey, Senior Archeologist with SHPO, regarding the potential need for additional survey work for cultural resources issues. Mr. McCluskey indicated that a survey to satisfy Section 106 of the National Historic Preservation Act would not be required for the property, because the site is owned by Entergy and not by the federal government. He said in the event that Entergy intends to conduct ground disturbing activities, a survey might be useful to Entergy to ensure that cultural resources are not adversely impacted. The application for relicensing of ANO Unit 1 involves no ground disturbing activities but instead represents a request for extension of the permit for the *status quo*, therefore, in the absence of a request for authorization of ground disturbing activities no survey would be required.

	Routing	Reviewed	Comments/Action
1	BMW	TKS	
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other** ________

ftn Associates Ltd.
water resources / environmental consultants

RECD OCT 12 1999 NRC
AHPP
OCT 6 - 1999 39349

September 2, 1999

Mr. George McCluskey
Senior Archeologist
State Historic Preservation Office
1500 Tower Building, 323 Center
Little Rock, AR 72201

RE: Cultural Resources Issues, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Mr. McCluskey:

The purpose of this letter is to follow up on our recent phone conversation regarding ongoing relicensing issues related to Entergy's Arkansas Nuclear One (ANO) facility. Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 by authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. That application, which again will be submitted to NRC, solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

We have corresponded with you previously regarding cultural resources issues within the boundaries of the power generating facilities, and you provided information regarding cultural resources sites in a letter to us dated June 18, 1999. At this time, however, we are requesting additional information from you regarding any potential impacts on cultural resources related to transmission line corridors leading from the ANO facility to points near Danville, Russellville, Morrilton, and Mabelvale, respectively. The enclosed map provides approximate locations for the transmission line corridors.

Please provide us with a written response as to whether you will require any cultural resources records searches or field surveys for areas located within the transmission line corridors. Again, we want to emphasize the fact that the current application to NRC involves no new construction or replacement of existing transmission lines. Instead, the application is concerned only with a request for an extension of the licensing period, i.e., until 2034, for the ANO facility.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For

Gary E. Tucker, PhD, PWS
Environmental Scientist

Enclosure

cc: Rick Buckley - Entergy

P:\WP_FILES\6045-061\L-GEORGE.WPD

Date 10/6/99
This undertaking will have no effect on significant historic properties.
Cathy Buford Slater
State Historic Preservation Officer

Attachment G

SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

Attachment G contains the following sections:

- G.1 – Melcor Accident Consequences Code System Modeling
- G.2 – Evaluation of Candidate SAMAs
- G.3 – Acronyms Used in Attachment G

G.1 MELCOR ACCIDENT CONSEQUENCES CODE SYSTEM MODELING

G.1.1 Introduction

The following sections describe the assumptions made and the results of modeling performed to assess the risks and consequences of severe accidents (U.S. NRC Class 9) at ANO-1.

The severe accident consequence analysis was carried out with the Melcor Accident Consequence Code System (Reference G.1-1). MACCS2 simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The principal phenomena considered in MACCS2 are atmospheric transport, mitigating actions based on dose projection, dose accumulation by a number of pathways including food and water ingestion, early and latent health effects, and economic costs.

G.1.2 Input

The input data required by MACCS2 are outlined below.

G.1.2.1 CORE INVENTORY

The core inventory (Table G.1-1) is for ANO-1 at a power level of 2568 megawatts-thermal. These values were obtained by adjusting the end-of-cycle values for a 3,412 megawatts-thermal pressurized water reactor by a linear scaling factor of 0.753 (Reference G.1-1).

G.1.2.2 SOURCE TERMS

The source term input data to MACCS2 were the severe accident source terms presented in the probabilistic risk assessment in the ANO-1 IPE (Reference G.1-2). This document defines the releases in terms of release modes and demonstrates the method of calculating releases. There are 53 release modes: 20 with early containment failure, 27 with late containment failure, and 6 with containment bypass as the failure mode. Table G.1-2 lists the input release fractions for each MACCS2 nuclide group together with the source category frequencies as calculated in the probabilistic risk assessment. For all modes the Ruthenium, Lanthanum, Cerium, and Barium fractions of the usual MACCS2 species are set to zero, as they were not reported in the IPE submittal. The assignment of the radionuclides in Table G.1-1 to these nuclide groups is the same as that given in the standard MACCS2 input. Where other related source term data were not reported, such as release durations and energies, these were evaluated by comparison with similar releases reported in the NUREG-1150 studies for the Surry plant (Reference G.1-3).

The amounts (becquerels) of each radionuclide released to the atmosphere for each accident sequence or release category are obtained by multiplying the (adjusted) core inventory at the time of the hypothetical accident (Table G.1-1) by the release fractions (Table G.1-2) assigned to each of the nuclide groups.

The offsite consequences are summed for all the release modes weighted by the annual frequency to obtain the total annual accident risk, for the base case and for each of the SAMA concepts evaluated. (This summation calculation is performed outside of the MACCS2 code as part of the SAMA cost benefit analyses.)

G.1.2.3 METEOROLOGICAL DATA

The MACCS2 input uses a full year of consecutive hourly values of windspeed, wind direction, stability class, and precipitation. This file describes one year's (1996) worth of hourly meteorological data for the plant as recorded at the site meteorological tower. However the site did not record precipitation data for this year. Precipitation data for this year was therefore obtained for the nearest available recording site. The data obtained was the hourly precipitation recorded for 1996 at Clarksville 6 NE COOP Station 03157 located at 35 deg 32 min N, 93 deg 24 min W. (about 20 miles NW of the plant site) (Reference G.1-4). The seasonal mixing heights for this area of Arkansas were taken from maps of mixing heights for the US.

MACCS2 calculations examine a representative subset of the 8,760 hourly observations contained in one year's data set (typically about 150 sequences). The representative subset is selected by sampling the weather sequences after sorting them into weather bins defined by windspeed, atmospheric stability, and rain conditions at various distances from the site.

G.1.2.4 POPULATION DISTRIBUTION

The predicted permanent resident population around the site for the year 2025 was distributed by location in a grid consisting of sixteen directional sectors, the first of which is centered on due north, the second on 22.5 degrees east of north, and so on. A summary of the population distribution is shown in Table G.1-3. The direction sectors were divided into 15 radial intervals extending out to 50 miles. The habitable land fraction for each grid element was calculated from land fraction data within a 50-mile radius of the plant.

The computer program SECPOP90 (Reference G.1-5) was used to process block-level 1990 census data (Reference G.1-6), as extracted in part to SECPOP90 data files, to prepare population estimates for the region surrounding the plant. The SECPOP90 census data file contains a record for the location (geometric centroid coordinates) and the population of each census block (6,660,337 records) in the continental U.S. If the centroid point met the distance criteria, it was then processed to determine the exact grid element in which it lies based on its radial distance and direction from the site. The population associated with that data point was then added to the population of that grid section. This process produced the raw 1990 population estimate for each rosette section. To these were added the transient populations in the emergency planning zone (exclusion boundary of 0.65 miles out to 10 miles) given in the Site Emergency Plan as estimated on a yearly average basis for each sector. The area is a popular recreational zone and it was considered appropriate to add in these people for dose purposes even if it results in an overestimate of the economic costs for non-farm property in this area.

The county-wide 1998 population estimates (Reference G.1-7) were then utilized to update the 1990 estimates to 1998. For each rosette section, the fraction of its area in each county was estimated. These fractions were then used to calculate a county-area weighted population growth factor (1998 county population divided by 1990 county population) for the section. The 1990 section population was then multiplied by this growth factor to produce the 1998 population estimate for that section.

The state-wide 1995-2025 Bureau of the Census data (Reference G.1-8) were then used to project the future rosette section populations for the year 2025. A statewide growth factor was calculated by dividing the state population projection for that year by the 1998 state population estimate. The section population projection for this step year was then calculated by multiplying the 1998 section population by the state growth factor.

Year 2025 population projections were used for the MACCS2 analyses as these are the endmost data produced by the Bureau of the Census and because it is about the midterm year of the proposed license extension period. It should be also noted that the MACCS2 population includes transient population estimates in the 10-mile zone around the plant as explained above in the EARLY file discussion. Hence the data in the MACCS2 site file are slightly larger in this zone that may be shown elsewhere in Tables of Population Projections for the ANO region.

G.1.2.5 EMERGENCY RESPONSE

Entergy Operations has a plan for the evacuation of the population within the plume exposure emergency planning zone. This zone is approximately a 10-mile radius centered on the ANO site. A site-specific evacuation study was been carried out by Entergy Operations (Reference G.1-9), and the evacuation modeling employed for the severe accident analysis was based primarily on this study.

The emergency evacuation model was modeled as a single radial evacuation zone extending out 10 miles from the plant. In the plan, it is stated that 80% of people will start moving 90 minutes after the alarm rings, 15% of the people will start moving 45 minutes after the alarm rings, and 5% of the people will start moving 135 minutes after the alarm rings. The clear times for each of the four zones were calculated by using weighted averages of the plan clear times for four different time periods, weekday, night, weekend, and adverse weekday. The average evacuation speed for the emergency zone was then estimated using the population-weighted average of the evacuation speed of each planning zone.

Because of the recreational nature of the area immediately surrounding the plant, the population in the emergency zone was augmented by adding the transient population to the census-based resident population. An average evacuation start time delay of 5130 seconds and an average radial evacuation speed of 1 m/s were estimated in the above manner.

For this analysis it was conservatively assumed that people beyond 10 miles would continue their normal activities unless the following predicted radiation dose levels are exceeded. At locations for which 50 rem whole body effective dose equivalent in one week is predicted, it was assumed that relocation would take place after half a day. If 25 rem whole body dose equivalent in one week is predicted, relocation of individuals in those sectors was assumed to take place after one day.

A sensitivity analysis was performed in which it was assumed that only 95 percent of the people within the emergency planning zone would participate in the evacuation. The remaining 5% were assumed to be unable or unwilling to evacuate and were assumed to go about their normal activities. The results were not significantly different on the whole from the complete evacuation case, for the purposes of the SAMA analyses. While the population doses increased and the evacuation costs decreased, the overall population exposure and accident mitigation costs are governed mainly by the long term effects over the whole 50-mile zone, and so the net changes were small, about one percent, which is not considered significant.

Another sensitivity analysis was performed to assess the importance of the calculated warning and release delay times. An arbitrary two hours was subtracted from all of the base case alarm and delay times, except the late release start time was decreased from 150,000 seconds to 86,400 seconds to effect a comparable change. The overall results were quantitatively quite similar to the evacuation effectiveness case of the preceding paragraph, with changes on the order of one percent.

The long-term phase was assumed to begin after one week and extend for five years. Long-term relocation was assumed to be triggered by a 4 rem whole body effective dose equivalent. Long-term protective measures were assumed to be based on generic protective action guideline levels for actions such as decontamination, temporary relocation, contaminated crops, and milk condemnation, and farmland production prohibition.

G.1.2.6 ECONOMIC DATA

Land use statistics including farmland values, farm product values, dairy production, and growing season information were provided on a countywide basis within 50 miles.

Much of the data was prepared by the computer program SECPOP90 (Reference G.1-5). It contains a database extracted from Bureau of the Census PL 94-171 (block level census) CD-ROMS (Reference G.1-6), the 1992 Census of Agriculture CD ROM Series 1B, the 1994 U.S. Census County and City Data Book CD-ROM, the 1993 and 1994 Statistical Abstract of the United States, and other minor sources. The reference contains details on how the database was created and checked. The SECPOP90 regional economic values were updated to 1997 using the Consumer Price Index (Reference G.1-10) and other data from the Bureau of the Census and the Department of Agriculture (Reference G.1-11).

Economic consequences were estimated by summing the following costs:

- Costs of evacuation,
- Costs for temporary relocation (food, lodging, lost income),
- Costs of decontaminating land and buildings,
- Lost return-on-investments from properties that are temporarily interdicted to allow contamination to be decreased by decay of nuclides,
- Costs of repairing temporarily interdicted property,
- Value of crops destroyed or not grown because they were contaminated by direct deposition or would be contaminated by root uptake, and
- Value of farmland and of individual, public, and non-farm commercial property that is condemned.

Costs associated with damage to the reactor, the purchase of replacement power, medical care, life-shortening, and litigation are not calculated by MACCS2.

G.1.3 Results

Based on the preceding input data, MACCS2 was used to estimate the following:

- The downwind transport, dispersion, and deposition of the radioactive materials released to the atmosphere from the failed reactor containment.
- The short-term and long-term radiation doses received by exposed populations via direct (cloudshine, plume inhalation, groundshine, and resuspension inhalation) and indirect (ingestion) pathways.
- The mitigation of those doses by protective actions (evacuation, sheltering, and post-accident relocation of people; disposal of milk, meat, and crops; and decontamination, temporary interdiction, or condemnation of land and buildings).
- The early fatalities and injuries expected to occur within one year of the accident (early health effects) and the delayed (latent) cancer fatalities and injuries expected to occur over the lifetime of the exposed individuals.

- The offsite costs of short-term emergency response actions (evacuation, sheltering, and relocation), of crop and milk disposal, and of the decontamination, temporary interdiction, or condemnation of land and buildings.

The consequences calculated with the MACCS2 model in terms of the population dose and offsite economic costs for the SAMA base case and the two evacuation-model sensitivity cases (95% EVACUATION and 2 HOUR) are shown in Table G.1-4. A common way in which this combination of factors is used to estimate risk is to multiply the frequencies by the consequences. The resultant risk is then expressed as the number, or magnitude, of consequences expected per unit time. Table G.1-5 shows average values of risk. These average values were obtained by summing the frequency multiplied by the consequences over the entire range of distributions. Because the probabilities are on a per reactor-year basis, the averages shown are also on a per reactor-year basis. A value of $2000 per rem and a discount factor of 7% per year were used to obtain the 20-year values.

Table G.1-1. ANO-1 Core Inventory.[1]

Nuclide	Core inventory (becquerels)	Nuclide	Core inventory (becquerels)
Cobalt-58	2.43E+16	Tellurium-131M	3.52E+17
Cobalt-60	1.86E+16	Tellurium-132	3.51E+18
Krypton-85	1.86E+16	Iodine-131	2.41E+18
Krypton-85M	8.73E+17	Iodine-132	3.56E+18
Krypton-87	1.59E+18	Iodine-133	5.10E+18
Krypton-88	2.16E+18	Iodine-134	5.60E+18
Rubidium-86	1.42E+15	Iodine-135	4.81E+18
Strontium-89	2.70E+18	Xenon-133	5.11E+18
Strontium-90	1.46E+17	Xenon-135	9.59E+17
Strontium-91	3.48E+18	Cesium-134	3.26E+17
Strontium-92	3.62E+18	Cesium-136	9.91E+16
Yttrium-90	1.57E+17	Cesium-137	1.82E+17
Yttrium-91	3.29E+18	Barium-139	4.73E+18
Yttrium-92	3.63E+18	Barium-140	4.68E+18
Yttrium-93	4.11E+18	Lanthanum-140	4.78E+18
Zirconium-95	4.16E+18	Lanthanum-141	4.39E+18
Zirconium-97	4.34E+18	Lanthanum-142	4.23E+18
Niobium-95	3.93E+18	Cerium-141	4.26E+18
Molybdium-99	4.59E+18	Cerium-143	4.14E+18
Technetium-99M	3.96E+18	Cerium-144	2.56E+18
Ruthenium-103	3.42E+18	Praseodymium-143	4.06E+18
Ruthenium-105	2.22E+18	Neodymium-147	1.82E+18
Ruthenium-106	7.77E+17	Neptunium-239	4.87E+19
Rhodium-105	1.54E+18	Plutonium-238	2.76E+15
Antimony-127	2.10E+17	Plutonium-239	6.22E+14
Antimony-129	7.43E+17	Plutonium-240	7.85E+14
Tellurium-127	2.03E+17	Plutonium-241	1.32E+17
Tellurium-127M	2.68E+16	Americium-241	8.73E+13
Tellurium-129	6.98E+17	Curium-242	3.34E+16
Tellurium-129M	1.84E+17	Curium-244	1.95E+15

1 Reference G.1-1.

Table G.1-2 ANO-1 RELEASE FRACTION BY NUCLIDE GROUP [2]

Release Mode[3]	Frequency[4]	Xenon/ Krypton	Iodine	Cesium	Tellurium	Strontium
A1	6.52E-10	9.20E-01	1.07E-04	9.02E-05	2.99E-05	4.17E-07
A2	2.91E-12	9.20E-01	4.29E-03	3.61E-03	1.10E-01	1.67E-05
A3	2.76E-08	9.20E-01	6.83E-04	5.74E-04	1.91E-04	2.66E-06
A4	4.94E-08	9.20E-01	2.73E-02	2.30E-02	7.62E-03	1.06E-04
B1	2.39E-11	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B2-L	6.16E-13	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B2-R	5.29E-13	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B3-L	5.26E-09	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B3-R	2.81E-10	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B4-L	3.75E-11	9.20E-01	9.96E-03	9.18E-03	2.40E-03	3.34E-05
B4-R	6.28E-12	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B5-L	5.45E-09	9.20E-01	8.82E-04	4.76E-04	1.13E-04	1.57E-06
B5-R	2.91E-10	9.20E-01	8.82E-04	4.76E-04	1.13E-04	1.57E-06
B6-L	4.08E-11	9.20E-01	4.04E-03	2.29E-03	2.03E-04	2.83E-06
B6-R	7.13E-12	9.20E-01	4.04E-03	2.29E-03	2.03E-04	2.93E-06
BP-D3A	4.01E-08	7.44E-01	2.10E-02	2.13E-02	1.51E-02	1.38E-04
BP-D3B	4.01E-08	9.20E-01	2.18E-01	2.21E-01	5.86E-02	1.14E-03
BP-E5A	1.00E-08	8.24E-01	2.12E-02	2.14E-02	1.54E-02	1.38E-04
BP-E5B	1.00E-08	1.00E+00	2.23E-01	2.25E-01	6.56E-02	1.14E-03
BP-E6A	3.56E-08	8.24E-01	2.84E-02	2.60E-02	2.43E-02	1.42E-04
BP-E6B	2.23E-07	1.00E+00	3.89E-01	3.43E-01	2.58E-01	1.16E-03
C1-L	4.42E-09	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C1-R	2.36E-10	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C2-L	2.34E-11	1.00E+00	1.03E-02	8.45E-03	4.26E-03	3.34E-05
C2-R	5.52E-12	1.00E+00	1.03E-02	8.45E-03	4.26E-03	3.34E-05
C3-L	3.95E-07	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C3-R	2.07E-08	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C4-L	1.03E-07	1.00E+00	2.12E-02	1.63E-02	3.03E-02	3.34E-05
C4-R	5.43E-09	1.00E+00	2.12E-02	1.63E-02	3.03E-02	3.34E-05

2 Reference G.1-2.

3 Release Modes notation:

A, B, C = late releases.

BP = bypass release modes

D, E = early releases

-R = containment rupture

-L = containment leak

4 Release Mode frequency per reactor year.

Table G.1-2 ANO-1 RELEASE FRACTION BY NUCLIDE GROUP [2]

Release Mode[3]	Frequency[4]	Xenon/ Krypton	Iodine	Cesium	Tellurium	Strontium
C5-L	2.70E-08	1.00E+00	1.26E-03	7.46E-04	1.11E-03	1.57E-06
C5-R	1.43E-09	1.00E+00	1.26E-03	7.46E-04	1.11E-03	1.57E-06
C6-L	7.39E-07	1.00E+00	1.53E-02	1.04E-02	2.81E-02	2.83E-06
C6-R	3.89E-08	1.00E+00	1.53E-02	1.04E-02	2.81E-02	2.83E-06
D1-L	9.14E-09	9.20E-01	1.41E-03	1.18E-03	3.81E-04	5.31E-06
D1-R	1.40E-08	9.20E-01	5.70E-03	4.79E-03	1.58E-03	2.20E-05
D2-L	1.72E-08	9.20E-01	5.60E-02	4.69E-02	1.52E-02	2.13E-04
D2-R	2.97E-08	9.20E-01	2.28E-01	1.91E-01	6.32E-02	8.80E-04
D3-L	3.70E-08	9.20E-01	5.11E-03	2.73E-03	7.19E-04	1.00E-05
D3-R	3.75E-08	9.41E-01	5.62E-02	3.66E-02	2.36E-02	3.41E-03
D4-L	7.51E-08	9.41E-01	2.02E-02	1.25E-02	6.27E-03	8.30E-04
D4-R	7.60E-08	9.41E-01	7.54E-02	4.70E-02	2.60E-02	3.44E-03
E1-L	2.10E-10	1.00E+00	2.66E-03	2.08E-03	2.37E-01	5.31E-06
E1-R	2.62E-10	1.00E+00	1.10E-02	8.57E-03	8.61E-03	2.20E-05
E2-L	3.86E-10	1.00E+00	5.72E-02	4.78E-02	1.90E-02	2.13E-04
E2-R	4.84E-10	1.00E+00	2.33E-01	1.95E-01	7.63E-02	9.90E-04
E3-L	6.08E-09	1.00E+00	2.66E-03	2.08E-03	2.37E-03	5.31E-06
E3-R	9.58E-09	1.00E+00	1.10E-02	9.57E-03	8.61E-03	2.20E-05
E4-L	4.50E-08	1.00E+00	9.35E-02	7.39E-02	7.11E-02	2.13E-04
E4-R	5.61E-08	1.00E+00	3.85E-01	3.05E-01	2.60E-01	8.80E-04
E5-L	9.27E-09	1.00E+00	6.36E-03	3.63E-03	2.71E-03	1.00E-05
E5-R	9.38E-09	1.00E+00	6.01E-02	3.94E-02	2.87E-02	3.41E-03
E6-L	5.46E-08	1.00E+00	4.77E-02	3.13E-02	4.73E-02	8.30E-04
E6-R	5.77E-08	1.00E+00	1.91E-01	1.30E-01	1.71E-01	3.44E-03

Table G.1-3. ANO-1 Regional Population Distribution (With Emergency Zone Transient Population)

	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	TOTALS
N	1,745	1,196	412	408	2,149	**5,910**
NNE	2,579	4,480	313	441	954	**8,767**
NE	17,156	5,376	2,240	421	1,532	**26,725**
ENE	13,361	3,469	2,349	2,146	5,630	**26,955**
E	5,757	6,702	10,460	5,911	25,094	**53,924**
ESE	5,235	742	5,567	3,825	44,444	**59,813**
SE	2,530	1,038	1,516	2,120	3,844	**11,048**
SSE	1,299	814	385	5,388	14,322	**22,208**
S	2,493	2,365	199	907	10,749	**16,713**
SSW	1,806	1,557	585	562	2,204	**6,714**
SW	644	3,514	716	714	697	**6,285**
WSW	366	1,326	1,023	1,391	1,593	**5,699**
W	67	275	5,878	9,327	7,572	**23,119**
WNW	1,240	2,068	5,173	11,604	4,735	**24,820**
NW	836	2,665	11,696	2,135	1,544	**18,876**
NNW	1,534	3,871	2,760	869	808	**9,841**
TOTALS	**58,648**	**41,458**	**51,272**	**48,169**	**127,871**	**327,418**

Table G.1-4 Summary of Offsite Consequence Results for Each Release Mode

	Population Dose, Sieverts			Offsite Economic Costs, $		
CET End Point (Release Mode)	Base	95% Evacuation	-2HR Alarm and Warning	Base	95% Evacuation	-2HR Alarm and Warning
A1	9.81E+01	9.84E+01	9.86E+01	4.02E+06	2.11E+06	4.04E+06
A2	9.77E+02	9.80E+02	9.75E+02	1.03E+08	1.01E+08	1.03E+08
A3	3.62E+02	3.63E+02	3.60E+02	2.46E+07	2.27E+07	2.49E+07
A4	2.40E+03	2.42E+03	2.41E+03	4.06E+08	4.05E+08	4.07E+08
B1	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B2-L	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B2-R	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B3-L	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B3-R	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B4-L	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B4-R	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B5-L	3.24E+02	3.25E+02	3.24E+02	2.10E+07	1.91E+07	2.16E+07
B5-R	3.24E+02	3.25E+02	3.24E+02	2.10E+07	1.91E+07	2.16E+07
B6-L	7.17E+02	7.19E+02	7.17E+02	8.67E+07	8.49E+07	8.61E+07
B6-R	7.31E+02	7.34E+02	7.23E+02	7.96E+07	7.77E+07	8.12E+07
BP-D3A	1.90E+03	1.92E+03	1.91E+03	3.52E+08	3.52E+08	3.52E+08
BP-D3B	4.71E+03	4.80E+03	4.74E+03	1.07E+09	1.07E+09	1.07E+09
BP-E5A	1.91E+03	1.92E+03	1.92E+03	3.53E+08	3.53E+08	3.53E+08
BP-E5B	4.79E+03	4.88E+03	4.82E+03	1.07E+09	1.07E+09	1.07E+09
BP-E6A	2.08E+03	2.10E+03	2.09E+03	4.05E+08	4.05E+08	4.05E+08
BP-E6B	6.92E+03	7.11E+03	6.97E+03	1.23E+09	1.23E+09	1.23E+09
C1-L	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C1-R	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C2-L	1.47E+03	1.48E+03	1.48E+03	2.02E+08	2.00E+08	2.03E+08
C2-R	1.47E+03	1.48E+03	1.48E+03	2.02E+08	2.00E+08	2.03E+08
C3-L	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C3-R	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C4-L	2.09E+03	2.11E+03	2.11E+03	3.31E+08	3.30E+08	3.33E+08
C4-R	2.09E+03	2.11E+03	2.11E+03	3.31E+08	3.30E+08	3.33E+08
C5-L	4.12E+02	4.14E+02	4.15E+02	3.50E+07	3.31E+07	3.52E+07
C5-R	4.12E+02	4.14E+02	4.15E+02	3.50E+07	3.31E+07	3.52E+07
C6-L	1.76E+03	1.71E+03	1.72E+03	2.48E+08	2.40E+08	2.42E+08
C6-R	1.71E+03	1.72E+03	1.72E+03	2.40E+08	2.38E+08	2.41E+08
D1-L	5.39E+02	5.40E+02	5.39E+02	4.89E+07	4.71E+07	4.89E+07
D1-R	9.24E+02	9.27E+02	9.74E+02	1.24E+08	1.23E+08	1.24E+08
D2-L	2.96E+03	2.97E+03	2.96E+03	6.93E+08	6.92E+08	6.93E+08
D2-R	4.86E+03	4.92E+03	4.90E+03	1.03E+09	1.03E+09	1.03E+09
D3-L	7.76E+02	7.79E+02	7.76E+02	9.99E+07	9.80E+07	9.99E+07
D3-R	2.36E+03	2.38E+03	2.38E+03	5.45E+08	5.45E+08	5.45E+08
D4-L	1.86E+03	1.87E+03	1.86E+03	2.81E+08	2.79E+08	2.81E+08
D4-R	2.62E+03	2.64E+03	2.64E+03	6.15E+08	6.15E+08	6.15E+08
E1-L	7.15E+02	7.19E+02	7.16E+02	7.74E+07	7.55E+07	7.74E+07

Table G.1-4 Summary of Offsite Consequence Results for Each Release Mode

	Population Dose, Sieverts			Offsite Economic Costs, $		
CET End Point (Release Mode)	Base	95% Evacuation	-2HR Alarm and Warning	Base	95% Evacuation	-2HR Alarm and Warning
E1-R	1.32E+03	1.32E+03	1.33E+03	1.81E+08	1.80E+08	1.81E+08
E2-L	2.99E+03	3.00E+03	2.99E+03	7.01E+08	6.99E+08	7.01E+08
E2-R	4.98E+03	5.05E+03	5.02E+03	1.04E+09	1.04E+09	1.04E+09
E3-L	7.15E+02	7.19E+02	7.16E+02	7.74E+07	7.55E+07	7.74E+07
E3-R	1.38E+03	1.38E+03	1.38E+03	1.98E+08	1.98E+08	1.98E+08
E4-L	3.49E+03	3.52E+03	3.49E+03	8.96E+08	8.95E+08	8.97E+08
E4-R	7.38E+03	7.52E+03	7.46E+03	1.19E+09	1.19E+09	1.19E+09
E5-L	9.34E+02	9.39E+02	9.35E+02	1.18E+08	1.16E+08	1.18E+08
E5-R	2.45E+03	2.47E+03	2.47E+03	5.69E+08	5.68E+08	5.69E+08
E6-L	2.76E+03	2.78E+03	2.76E+03	5.42E+08	5.40E+08	5.42E+08
E6-R	4.52E+03	4.60E+03	4.57E+03	9.32E+08	9.32E+08	9.32E+08

Table G.1-5. Summed Average Risks

OFFSITE RISKS			
(Annual)	BASE	95%EVAC	-2hr alrm
REMS	0.5532	0.5568	0.5528
DOLLARS	$ 956	$ 949	$ 953
OFFSITE RISKS			
(20 year)	BASE	95%EVAC	-2hr alrm
EQ. REM	$ 11,908	$ 11,986	$11,899
DOLLARS	10,290	10,209	10,255
TOTALS	$ 22,198	$ 22,195	$22,153
DELTA From BASE		95%EVAC	-2hr alrm
$		$ (4)	$ (45)
%		-0.02%	-0.20%

G.1.4 References

G.1-1 *Code Manual for MACCS2: Volume 1, User's Guide*, Chanin, D. I., et al, SAND07-054, March 1997. SEE ALSO:

MACCS2 V.1.12, CCC-652 Code Package, ORNL (Oak Ridge National Laboratory RISCC Computer Code Collection), 1997.

MELCOR Accident Consequence Code System (MACCS) Model Description, Jow, H. N, et al, NUREG/CR-4691, SAND86-1562, February 1990.

G.1-2 *ANO-1 Probabilistic Risk Assessment Summary Report, IPE Submittal*, Entergy Operations, Inc., USNRC Docket # 05000313, April 1993.

G.1-3 *Evaluation of Severe Accident Risks: Surry 1 Main Report*, NUREG/CR-4551, Vol. 3, Rev. 1, Part 1, Breeding, R. J., et al, October 1990.

G.1-4 *1996 Hourly Precipitation Data for Clarksville 6 NE COOP ID 031457*, NCDC (National Climatic Data Center, National Oceanic and Atmospheric Administration), Order Num. 6394, May 7, 1999.

G.1-5 *SECPOP90: Sector Population, Land Fraction, and Economic Estimation Program*, NUREG/CR-6525, Humphreys, S. L., et al, September, 1997.

G.1-6 *Census of Population and Housing, 1990: Public Law (P. L.) 94-171, Data Technical Documentation*, CD – ROM set , BOC (Bureau of the Census, U. S. Dept. of Commerce), 1991.

G.1-7 *County Population Estimates for July 1, 1998 and Population Change for April 1, 1990 to July 1, 1998 (includes revised April 1, 1990 Census Population Counts)*, BOC (Bureau of the Census, Statistical Information Staff, Population Division), CO-98-002, Released to Internet, March 12, 1999.

G.1-8 *Population Projections: States, 1995-2025*, Census Bureau, U. S. Department of Commerce P25-1131, , BOC (Bureau of the Census), Campbell, Paul, May 1997.

G.1-9 *ANO Emergency Plan*, Entergy Operations, Inc., 1981.

G.1-10 *Consumer Price Index-All Urban Consumers*, Series Catalog: Series ID: CUUR0300SA0, BOL (U.S. Bureau of Labor), 1999.

G.1-11 *1997 Census of Agriculture*, DOA (U.S. Dept. of Agriculture, National Agricultural Statistics Service) 1997.

G.1-12 *Regional Population 2000-2030 Projections*, SCIENTECH, Inc. ANO-1 Project 17071 AF-2, Fulford, P. J., September 13, 1999.

G.1-13 *Evaluation of Severe Accident Risks: Quantification of Major Input Parameters MACCS Input*, NUREG/CR 4557, Vol. 2, Rev. 1., Part 7, Sprung, J. L. et al, December 1990.

G.2 EVALUATION OF CANDIDATE SAMAs

This section describes the generation of the initial list of potential SAMAs for ANO-1, screening methods and the analysis of the remaining SAMAs.

G.2.1 SAMA List Compilation

Entergy Operations generated a list of candidate SAMAs by reviewing industry documents and considering plant-specific enhancements not considered in published industry documents. Industry documents reviewed include the following:

- The ANO-1 IPE submittal (Reference 1 in Section G.2-5)
- The Watts Bar Nuclear Plant Unit 1 PRA/IPE submittal (Reference 2 in Section G.2-5)
- The Limerick SAMDA cost estimate report (Reference 3 in Section G.2-5)
- NUREG-1437 description of Limerick SAMDA (Reference 4 in Section G.2-5)
- NUREG-1437 description of Comanche Peak SAMDA (Reference 5 in Section G.2-5)
- Watts Bar SAMDA submittal (Reference 6 in Section G.2-5)
- TVA response to NRC's RAI on the Watts Bar SAMDA submittal (Reference 7 in Section G.2-5)
- Westinghouse AP600 SAMDA (Reference 8 in Section G.2-5)
- Safety Assessment Consulting (SAC) presentation by Wolfgang Werner at the NUREG 1560 conference (Reference 9 in Section G.2-5)
- NRC IPE Workshop - NUREG 1560 NRC Presentation (Reference 10 in Section G.2-5)
- NUREG 0498, supplement 1, section 7 (Reference 11 in Section G.2-5)
- NUREG/CR-5567, PWR Dry Containment Issue Characterization (Reference 12 in Section G.2-5)
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program (Reference 13 in Section G.2-5)
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Reference 14 in Section G.2-5)
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Reference 15 in Section G.2-5)
- CE System 80+ Submittal (Reference 16 in Section G.2-5)
- NUREG 1462, NRC Review of ABB/CE System 80+ Submittal (Reference 17 in Section G.2-5)
- An ICONE paper by C. W. Forsberg, et. al, on a core melt source reduction system (Reference 18 in Section G.2-5)

Although ANO-1 is a B&W design, each of the above documents were reviewed for potential SAMAs even if they were not necessary applicable to a B&W plant. Those items not applicable to ANO-1 were subsequently screened from this list. The containment performance improvement programs for boiling water reactors and ice condenser plants were not reviewed (and the NUREG-1560 portion of the containment performance improvement for these were not reviewed). Conceptual enhancement for which no specific details were available (e.g., "improve diesel reliability" or "improve procedures for loss of support systems") were not included, unless they were considered as vulnerabilities in the ANO-1 IPE.

G.2.2 Qualitative Screening of SAMAs

The initial list of potential SAMAs are presented in Table G.2-1. Table G.2-1 also presents a qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- The SAMA is not applicable at ANO-1, either because the enhancement is only for boiling water reactors, the Westinghouse AP600 design or PWR ice condenser containments, or it is a plant specific enhancement that does not apply at ANO-1 (Criterion A – Not applicable); or
- The SAMA has already been implemented at ANO-1 (or the ANO-1 design meets the intent of the SAMA) (Criterion B – Implemented or intent met).

Based on preliminary screening, 80 improvements were eliminated, leaving 89 subject to the final screening process (Criterion N – Not initially screened). These improvements are listed in Table G.2-2.

The final screening process involved identifying and eliminating those items whose cost exceeded their benefit. Table G.2-2 provides a description of the evaluation of each and provides the basis for their elimination or describes their final resolution.

G.2.3 Analysis of Potential SAMAs

The approach selected for this portion of the analysis (potential SAMAs to reduce core damage frequency) is to calculate the value of the averted risk to the public for each alternative. It relies on the NRC's handbook (Reference 20 in Section G.2-5) to convert public health risk (person-rem) into dollars to estimate the cost of the public health consequences. The requirement established in this handbook is to use $2,000 per person-rem to convert public health consequences to dollars (not indexed to inflation). Therefore, the value (or safety improvement) of implementing an alternative is expressed in terms of averted cost to the public (public benefit). It should be noted that the maximum attainable benefit for any improvement is, hypothetically, the elimination of all plant risk. The expected cost of some SAMAs exceed this benefit and can be eliminated on this basis in the cost-benefit analysis.

The evaluation process described in Reference 20 of Section G.2-5 calculates the value of averted risk on an annual basis. Therefore, a method of "discounting" is used to calculate the "present value" or "present worth of averted risk" based on a specified period of time. For this analysis, a discount factor of 7% as described in the NRC Regulatory Analysis Technical Evaluation Handbook was used to determine the present worth of averted risk over the 20-year license renewal period for ANO-1.

The PSA results used in this analysis are calculated using internal event results only. To account for the potential impact of external events on the results of these SAMA evaluations, since ANO-1 does not currently have an external events PSA model, the benefits of each SAMA were doubled for purposes of comparing with its cost.

G.2.4 Sensitivity Analyses

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.13.4 of the ER used the 7% discount rate in calculating benefits of all the unscreened SAMAs. Entergy Operations also performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs.

Other sensitivities were performed; each of the sensitivities resulted in an additional benefit result for each of the SAMAs analyzed in the cost-benefit analysis. In addition to the discount rate sensitivity discussed above, the sensitivities performed include:

- Calculation of the benefit assuming the baseline discount rate and assuming external events contributed an amount equivalent to internal events to the CDF.
- Calculation of the benefit assuming averted onsite costs included the cost of replacement power and assuming the baseline discount rate.
- Calculation of the benefit assuming averted onsite costs included the cost of repair/refurbishment and assuming the baseline discount rate.
- Calculation of the benefit assuming a discount rate that is realistic for Entergy Operations (15%).

The benefits calculated for each of these sensitivities are presented in Table G.2-3

G.2.5 References

1. "Arkansas Nuclear One Unit 1 Probabilistic Risk Assessment Summary Report", April 1993, Entergy Operations.
2. Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk, dated September 1, 1992. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Generic Letter (GL) 88-20 – Individual Plant Examination (IPE) for Severe Accident Vulnerabilities – Response – (TAC M74488)."
3. "Cost Estimate for Severe Accident Mitigation Design Alternatives. Limerick Generating Station for Philadelphia Electric Company," Bechtel Power Corporation, June 22, 1989.
4. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.35, Listing of SAMDAs considered for the Limerick Generating Station, NRC, May 1996.
5. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, NRC, May 1996.
6. Letter from Mr. W. J. Museler (TVA) to NRC Document Control Desk, dated June 5, 1993. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) - (TAC Nos. M77222 and M77223)."
7. Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated October 7, 1994. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) – Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."
8. Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."
9. Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC – IPE Workshop Summary/ Held in Austin Texas; April 7-9 1997," dated July 17, 1997/Appendix F – Industry Presentation Material, Contribution by Swedish Nuclear Power Inspectorate (SKI) and Safety Assessment Consulting (SAC): "Insights from PSAs for European Nuclear Power Plants," presented by Wolfgang Werner, SAC.
10. Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC – IPE Workshop Summary/ Held in Austin Texas; April 7-9 1997," dated July 17, 1997/Appendix D – NRC Presentation Material on Draft NUREG-1560.
11. NUREG 0498, "Final Environmental Statement related to the operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, NRC, April 1995.
12. NUREG/CR-5567, "PWR Dry Containment Issue Characterization," NRC, August 1990.
13. NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, NRC, December 1997.

14. NUREG/CR-5630, "PWR Dry Containment Parametric Studies," NRC, April 1991.
15. NUREG/CR-5575, "Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment," NRC, August 1990.
16. CESSAR Design Certification, Appendix U, Section 19.15.5, Use of PRA in the Design Process, December 31, 1993.
17. NUREG 1462, "Final Safety Evaluation Report Related to the Certification of the System 80+ Design," NRC, August 1994.
18. Forsberg, C. W., E. C., Beahm, and G. W. Parker, "Core-Melt Source Reduction System (COMSORS) to Terminate LWR Core-Melt Accidents," Second International Conference on Nuclear Engineering (ICONE-2) San Francisco, California, March 21-24, 1993.
19. "Summary Report of Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities for Arkansas Nuclear One, Unit 1," May 1996, Entergy Operations.
20. "Regulatory Analysis Technical Evaluation Handbook", NUREG/BR-0184, January 1997.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
1	Cap downstream piping of normally closed ICW drain and vent valves	Reduces the frequency of loss of ICW initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
2	Enhance Loss of ICW (or LOSW) procedure to facilitate stopping RCPs	Reduces potential for RCP failure due to loss of seal cooling and seal injection.	(1), (2), (10), (13)	B	ANO-1 has procedure 1203.031 (Reactor Coolant Pump and Motor Emergency) which provides procedural guidance for required actions following a loss of seal cooling. This procedure is deemed to be adequate to ensure that the RCPs will be stopped after loss of cooling.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	Potential reduction in the probability of RCP seal failure.	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
4	Additional training on the Loss of ICW	Potential improvement in success rate of operator actions after a loss of ICW.	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
5	Provide hardware connections to allow another ERCW (SW) to cool makeup pump seals	Reduce effect of loss of SW by providing a means to maintain the makeup pump seal injection after a loss of SW. Note, in Watts Bar, this capability was already there for one charging pump at one unit, and the potential enhancement identified was to make it possible for all of the charging pumps	(2), (6), (11), (13)	A	ANO-1 Make Up Pumps do not require SW for seal cooling. SW is only required for lube oil cooling on the Make Up Pump. Therefore, this item does not apply to ANO. See SAMA #7 for an evaluation of enhancing the lube oil cooling subsystem.
6	On loss of ERCW (SW), proceduralize shedding ICW loads to extend the ICW heatup time	Increase time before the loss of ICW (and RCP seal failure) in the loss of ERCW sequences.	(2)	A	Upon loss of cooling to ICW, other loads would take precedence over continued operation of the RCPs. The RCPs would be stopped so the need for cooling would be obviated. Seal injection would still be available, also.
7	Increase makeup pump lube oil capacity	Would lengthen time before makeup pump failure due to lube oil overheating in loss of SW sequences	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
8	Eliminate RCP thermal barrier dependence on ICW, such that loss of ICW does not result directly in core damage.	Would prevent loss of RCP seal integrity after a loss of ICW. Watts Bar IPE said they could do this with ERCW connection to makeup pump seals.	(2), (13)	B	The suggestion was for the Watts Bar plant at which RCP thermal barrier cooling is dependent on CCW. At ANO-1 thermal barrier cooling is not dependent on ICW (the ANO-1 equivalent system to CCW) as the seal injection pumps can continue to supply seal cooling during a loss of ICW. Therefore the suggestion is considered to be already incorporated at ANO-1.
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	(5)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW or SBO.	(6), (11), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW, but not SBO.	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
12	Use existing hydro test pump for RCP seal injection	Independent seal injection source, without cost of a new system	(7)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
13	Replace ECCS pump motors with air cooled motors	Remove dependency on ICW	(10), (13)	B	The ECCS pump motors are already air cooled in the ANO-1 design. (lube-oil coolers require SW, however other plant change evaluations show that the cost of removing this dependency is much greater than the benefit achieved)
14	Install improved RCP seals	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA	(11), (13)	A	Seals in ANO-1 are B-J 9000 series and are currently not expected to fail with cooling available. Improvements to the seals are therefore not needed.
15	Add a third ICW pump	Reduce chance of loss of ICW leading to RCP seal LOCA	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
16	Prevent makeup pump flow diversion from the relief valves	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
17	Change procedures to isolate RCP seal return flow on loss of ICW, and guidance on loss of injection during seal LOCA.	Reduce CDF from loss of seal cooling.	(13)	B	ANO-1 has procedure 1203.031 (Reactor Coolant Pump and Motor Emergency) which provides procedural guidance for required actions following a loss of seal cooling.
18	Procedures to stagger HPI pump use after a loss of SW	Allow high pressure injection to be extended after a loss of SW	(1), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
19	Use firewater pumps as a backup seal injection and high pressure makeup	Reduce RCP seal LOCA frequency and SBO core damage frequency	(13)	A	Fire water does not have sufficient discharge pressure to be used for RCP seal injection. Current procedural direction is to stop RCPs upon loss of seal cooling. The use of fire water as a backup reactor vessel makeup source is applicable to BWR only since it is not borated water and is provided at low discharge pressure.
20	Procedural guidance for use of cross-tied ICW or SW pumps	Can reduce the frequency of the loss of either of these.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
21	Procedure & training enhancements in support system failure sequences	Potential improvement in success rate of operator actions after support system failures due to more procedural guidance on anticipating problems and coping.	(2), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
22	Improve ability to cool RHR heat exchangers	Reduced chance of loss of DHR by 1)Performing procedure and hardware modification to allow manual alignment of fire protection system to the ICW system, or 2)Installing an ICW header cross-tie	(12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
23	Stage backup fans in Switchgear rooms	Provides alternate ventilation in the event of a loss of switchgear ventilation.	(13)	A	ANO-1 PSA does not include dependency on HVAC
24	Provide redundant train of ventilation to 480V board room.	Would improve reliability of 480V HVAC. At Watts Bar, only one train of HVAC cools the 480V board room that contains the unit vital inverters, and recovery actions are heavily relied on. Watts Bar IPE said their corrective action program is dealing with this.	(2), (13)	A	ANO-1 PSA does not include dependency on HVAC

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
25	Procedures for temporary HVAC	Provides for improved credit to be taken for loss of HVAC sequences	(11), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
26	Add a switchgear room high temp alarm	Improve diagnosis of a loss of switchgear HVAC	(13)	A	ANO-1 PSA does not include dependency on HVAC. In addition, local fan units are actuated based upon temperature limits as per Procedure 1104.027.
27	Create ability to switch fan power supply to DC in SBO	(Was created for a BWR RCIC room, Fitzpatrick; possible for turbine AFW if has its own fan) Allow continued operation in SBO	(13)	A	ANO-1 PSA does not include dependency on HVAC
28	Delay containment spray actuation after large LOCA	When ice remains in the ice condenser at such plants, containment sprays have little impact on containment performance, yet rapidly drain down the BWST. This improvement would lengthen time of BWST availability.	(2), (6)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
29	Install containment spray throttle valves	Can extend the time over which water remains in the BWST, when full containment spray flow is not needed.	(11), (12), (13)	A	Not Applicable - ANO-1 already has the capability to throttle RB spray. Procedure 1202.10 requires the operator to throttle spray flow in order to balance the flow and lengthen the time that water is available in the BWST for certain events.
30	Install an independent method of suppression pool cooling	Would decrease frequency of loss of containment heat removal	(3), (4)	A	This is applicable only to BWR.
31	Develop an enhanced drywell spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	(3), (4), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
32	Provide a dedicated existing drywell spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	(3), (4) (similar in (5), (6), (11))	N	Not initially screened. Considered further in the final (cost-benefit) screening.
33	Install a containment vent large enough to remove ATWS decay heat	Assuming injection is available, would provide alternative decay heat removal in an ATWS	(3), (4)	A	Not applicable to PWRs
34	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	(3), (4), (5), (6), (8), (11), (12), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
35	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	(3), (4), (9), (14)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
36	Create/enhance hydrogen igniters with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	(3), (5), (6), (7), (9), (12), (13), (14), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
37	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	(7), (11), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through.	(3), (4), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
39	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	(3), (4), (8), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
40	Provide modification for flooding of the drywell head	Would help mitigate accidents that result in leakage through the drywell head seal	(4), (9)	A	This is applicable only to BWR.
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	(4)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
42	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	(5), (6), (9), (11), (12), (13), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
43.1	Creating other options for reactor cavity flooding (Part a)	(a)Use water from dead-ended volumes, the condensed blowdown of the RCS, or secondary system by drilling pathways in the reactor vessel support structure to allow drainage from the steam generator compartments, refueling canal, sumps, etc., to the reactor cavity. Also (for ice condensers), allow drainage of water from melted ice into the reactor cavity.	(7), (9), (13)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
43.2	Creating other options for reactor cavity flooding (Part b)	(b)Flood cavity via systems such as diesel driven fire pumps	(7), (9), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
44	Enhance air return fans (ice condenser containment)	Provide an independent power supply for the air return fans, reducing containment failure in SBO sequences	(6), (11)	A	Not Applicable to ANO-1. However, credit for the existing black diesel as an additional power supply is taken.
45	Provide a core debris control system	(Intended for ice-condenser plants): Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	(6), (11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
46	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	(18)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
47	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	(6), (9), (11), (14)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
48	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	(7), (9), (10), (12)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
49	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
50	Secondary containment filtered ventilation	For plants with a secondary containment, would filter fission products released from the primary containment	(8)	A	Not Applicable to ANO-1. No secondary containment building.
51	Increase containment design pressure	Reduce chance of containment overpressure	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	Prevent basemat melt through	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
53	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
54	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
55	Add ribbing to the containment shell	Would reduce the chance of buckling of containment under reverse pressure loading.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
56	Reactor Building Liner Protective Barrier	A protective barrier inside the incore instrument tunnel or along the reactor building liner just beyond the tunnel could prevent certain types of containment failure, which could result in a notable reduction in the large release frequency.	(1)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
57	Train operations crew for response to inadvertent actuation signals	Improves chances of a successful response to the loss of two 120V AC buses, which causes inadvertent signals.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
58	Proceduralize alignment of spare diesel to shutdown board after LOP and failure of the diesel normally supplying it	Reduced SBO frequency.	(2)	B	Such procedures have already been implemented.
59	Provide an additional diesel generator	Would increase on-site emergency AC power reliability and availability (decrease SBO) The ANO1 IPE reported that ANO committed to install an AAC power source capable of supplying the LOOP loads of any one the four safety buses. This source would be available within 10 minutes after determination of SBO conditions.	(1), (5), (6), (10), (13) (16), (17)	B	ANO-1 has already installed a diverse DG capable of powering either Class 1E bus.
60	Provide additional DC battery capability	Would ensure longer battery capability during a SBO, reducing frequency of long term SBO sequences.	(5), (6), (13), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
62	Procedure to cross tie HPCS diesel	(BWR 5/6)	(10)	A	Not Applicable to ANO-1. Applicable to BWR 5/6.
63	Improved bus cross tie ability	Improved AC power reliability	(10), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
64	Alternate battery charging capability	Improved DC power reliability. Either cross tie of AC buses, or a portable diesel-driven battery charger.	(10), (11), (12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
65	Increase/improve DC bus load shedding	Improved battery life in station blackout	(10), (11), (12), (13)	B	An analysis was performed in support of the ANO-1 PSA update that credited the black batteries for load shedding of the vital batteries. This analysis provided the basis for extending the vital battery life from 2 to 5 hours. This improvement is considered to be already implemented at ANO-1.
66	Replace batteries	Improved reliability	(10)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
67	Create AC power cross tie capability across units at a multi-unit site	Improved AC power reliability	(11), (12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
68	Create a cross-unit tie for diesel fuel oil	For multi-unit sites, adds diesel fuel oil redundancy.	(13)	B	The combination of day tank and fuel oil storage tank for each diesel provides for a 3.5 day fuel oil supply. Makeup to the fuel oil storage tanks is provided from the bulk diesel fuel oil storage tank through a filter. This tank has a capacity of 185,000 gallons. The combination of all diesel fuel oil storage provides for greater than 14 day supply. FSAR section 8.3.1.1.7.2 discusses alternatives even under conditions of extended flooding and limited site access. additionally ANO-1 already has the capability to crosstie the fuel pumps from ANO-2 to ANO-1, and this has been considered as a recovery in the ANO-1 PRA.
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
71	Develop a severe weather conditions procedure	For plants that do not already have one, reduces the likelihood of external events CDF.	(13)	B	Such a procedure currently exists and it is being revised to further enhance guidance provided.
72	Procedures for replenishing diesel fuel oil	Allow long-term diesel operation	(13)	B	The combination of day tank and fuel oil storage tank for each diesel provides for a 3.5 day fuel oil supply. Makeup to the fuel oil storage tanks is provided from the bulk diesel fuel oil storage tank through a filter. This tank has a capacity of 185,000 gallons. The combination of all diesel fuel oil storage provides for greater than 14 day supply. FSAR section 8.3.1.1.7.2 discusses alternatives even under conditions of extended flooding and limited site access. The intent of this improvement is considered to be met.
73	Install gas turbine generators	Improve on-site AC power reliability	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
74	Install tornado protection on gas turbine generator	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
75	Create a river water backup for diesel cooling.	Provides redundant source of diesel cooling.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
76	Use firewater as a backup for diesel cooling	Redundancy in diesel support systems	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
77	Provide a connection to alternate offsite power source	Increase offsite power redundancy	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
78	Implement underground offsite power lines	Could improve offsite power reliability, particularly during severe weather.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
79	Replace anchor bolts on diesel generator oil cooler	Millstone found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk.	(13)	B	Since this is not on seismic issues list, a similar condition was not found at ANO-1. Additionally, the oil coolers for ANO-1 DGs are part of the DG skid and as such are considered to be seismically adequate for ANO-1. The intent of this improvement is considered to be met.
80	Proceduralize use of pressurizer vent valves during SGTR sequences	CCNP procedures direct the use of pressurizer sprays to reduce RCS pressure after a SGTR. Use of the vent valves provides a backup method.	(13)	A	Not Applicable - ANO-1 has ERVs and auxiliary spray that could be utilized for depressurization but does not have remotely operated pressurizer vents. (See also #151.)
81	Install a redundant spray system to depressurize the primary system during a SGTR.	Enhanced depressurization ability during SGTR.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
82	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	(7), (9), (10), (13), (14), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	(a)A highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources, (b)a system which returns the discharge from the steam generator relief valve back to the primary containment, (c)an increased pressure capability on the steam generator shell side with corresponding increase in the safety valve setpoints.	(7), (8), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	(8), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
85	Replace steam generators with new design	Lower frequency of SGTR	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
86	Revise EOPs to direct that a faulted steam generator be isolated.	For plants whose EOPs don't already direct this, would reduce consequences of a SGTR	(13)	B	ANO-1 procedures already direct isolation of a faulted SG.
87	Direct steam generator flooding after a SGTR, prior to core damage.	Would provide for improved scrubbing of SGTR releases.	(14), (15)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	Reduce chances of tube rupture	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
89	Locate RHR inside of containment	Would prevent ISLOCA out the RHR pathway	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
90	Provide self-actuating containment isolation valves	For plants that don't have this, it would reduce the frequency of isolation failure	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
91	Install additional instrumentation for ISLOCA sequences	Pressure or leak monitoring instruments installed between the first two pressure isolation valves on low-pressure injection lines, RHR suction lines, and high pressure injection lines would decrease ISLOCA frequency.	(5), (6), (11), (13)	B	ANO-1 already has pressure transmitters between the first two pressure isolation valves for LPI and the RHR suction valves which are monitored regularly. (The HPI lines are designed for RCS pressure and do not present a possible ISLOCA scenario).
92	Increase frequency of valve leak testing	Decrease ISLOCA frequency	(12)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
93	Improve operator training on ISLOCA coping	Decrease ISLOCA effects	(12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
94	Install relief valves in the ICW system	Would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
95	Provide leak testing of valves in ISLOCA paths	At Kewaunee, four MOVs isolating RHR from the RCS were not leak tested. Will help reduce ISLOCA frequency	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
96	Revise EOPs to improve ISLOCA identification	Salem had a scenario in which an RHR ISLOCA could direct initial leakage back to the PRT, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
97	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	(14), (15)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
98	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
99	Keep LPI/DHR and RB Spray Pump drains closed.	LPI pumps will not be affected by an ISLOCA which discharges into the auxiliary building.	(1)	B	This has been previously implemented. The LPI\DHR and RB Spray pump room drain isolation valves were changed from normally open to normally closed.
100	Valve Position Verification	The ANO1 IPE indicates one valve in the reactor building air monitoring leak detection system that can present a challenge to reactor building integrity during an SBO. On a degraded power or SBO condition, CV-7453 (an MOV) may not close; in this condition it is important to verify the other valve (CV-7454) closed to ensure reactor building integrity.	(1)	B	IPE improvement implemented per M.E. Byram letter dated 20Dec1994, subj. "ANO-1 PRA Potential Plant Improvements".

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
101	Conserve BWST inventory post accident	Modify procedures to conserve the Borated Water Storage Tank during SGTRs. Alternatively BWST refill could be utilized to provide long term injection capability (see item #83).	(1)	B	This item has been implemented per owner's group SAMG guidelines. The intent of this improvement is considered to be met.
102	Removal and Flanging of the Hydrogen Purge Valves	The hydrogen purge system is not used (at the time of the IPE); the outboard RB isolation valves (CV-7443, CV-7445, CV-7447, CV-7449) are locked closed with their breakers removed. The inboard valves are left open following an event to allow for hydrogen monitoring.	(1)	B	IPE improvement implemented per M.E. Byram letter dated 20Dec1994, subj. "ANO-1 PRA Potential Plant Improvements".
103	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment	For a plant where internal flooding from turbine building to safeguards areas is a concern, this modification can prevent flood propagation.	(13)	A	The ANO-1 internal flood analysis report was reviewed and no similar concerns were identified.
104	Improve inspection of rubber expansion joints on main condenser	For a plant where internal flooding due to failure of circulating water expansion joint is a concern, this can help reduce the frequency.	(13)	A	The ANO-1 internal flood analysis report was reviewed and no similar concerns were identified.
105	Internal flood prevention and mitigation enhancements	1)Use of submersible MOV operators. 2)Back flow prevention in drain lines.	(13)	A	The ANO-1 internal flood analysis report was reviewed. All rooms affected by flood propagation through floor drains were determined to have a core damage frequency due to the flooding concerns that was lower than the screening frequency.
106	Internal flooding improvements at Fort Calhoun	Prevention or mitigation of 1)A rupture in the RCP seal cooler of the ICW system, 2)An ISLOCA in a shutdown cooling line, 3)An AFW flood involving the need to possibly remove a watertight door. For a plant where any of these apply, would reduce flooding risk.	(13)	A	The ANO-1 internal flood analysis report was reviewed and these scenarios are either not applicable to ANO-1 or are insignificant contributors to CDF.
107	Install digital feedwater upgrade	Reduces chance of loss of MFW following a plant trip.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
108	Perform surveillances on manual valves used for backup AFW pump suction	Improves success probability for providing alternate water supply to AFW pumps.	(13)	B	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The Service water backup valves are surveilled. No significant gain would result from testing these valves. No action is required.
109	Install manual isolation valves around AFW turbine driven steam admission valves	Reduces the dual turbine driven pump maintenance unavailability.	(13)	A	ANO-1 does not have a dual TD pump configuration.
110	Install accumulators for turbine driven AFW pump flow control valves	Provide control air accumulators for the turbine driven AFW flow control valves, the motor driven AFW pressure control valves, and S/G PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOP.	(11)	A	ANO-1 TDP does not have AOVs for control valves.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
111	Install a new CST (AFWST)	Either replace old tank with a larger one, or install a backup tank	(13), (16), (17)	B	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The current CST is analyzed to have a 24 hour capacity. No action is required.
112	Cooling of steam driven AFW pump in a SBO	1)Use firewater to cool pump, or 2)Make the pump self-cooled. Would improve success chances in a SBO	(13)	A	Not Applicable - Both the MD and TD EFW pumps are self cooled.
113	Proceduralize local manual operation of AFW when control power is lost	Lengthen AFW availability in SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.	(13)	B	ANO-1 already has a procedure which addresses the ability to take local manual control of the steam flow to the turbine driven pump if automatic control is lost due to a loss of power.
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
115	Add a motor train of AFW to the steam trains.	For PWRs that do not have any motor trains of AFW, this can increase reliability in non-SBO sequences.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
116	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	Would be a backup water supply for the feedwater/condensate systems.	(12)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an alternate source.
117	Use firewater as a backup for steam generator inventory	Would create a backup to main and auxiliary feedwater for steam generator water supply	(13)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an alternate source.
118	Procure a portable diesel pump for isolation condenser makeup	Backup to the city water supply and diesel fire water pump in providing isolation condenser makeup	(13)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
119	Install an independent diesel for the condensate storage tank makeup pumps	Would allow continued inventory in CST during a SBO	(13)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The current CST is analyzed to have a 24 hour capacity. No action is required.
120	Change failure position of condenser makeup valve.	If the condenser makeup valve fails open on loss of air or power, this can prevent CST flow diversion to condenser. Allows greater inventory for the EFW pumps.	(13)	A	Not Applicable - ANO-1 does not have a pneumatic valve in the position referred to in this SAMA. ANO-1 has a locked closed manual 3-way valve in this location, which is locked closed to the condenser.
121	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
122	EFW Pump Common Discharge Valve	Removal of the internals of manual valve FW-1016 (common discharge valve from the EFW pumps to the Circulating Water Flume) would reduce the likelihood of loss of both EFW trains due to valve closure. The function of this valve (isolation of the EFW pumps for maintenance) is redundant with individual pump discharge isolation valves.	(1)	B	This modification was implemented per plant change PC 95-7081
123	Provide capability for diesel driven, low pressure vessel makeup	Extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., firewater)	(4), (5), (13)	A	The proposed modification applies primarily to BWRs (for ANO-1 a diverse high pressure injection provides more benefit and is analyzed in #84). At ANO-1 only hardware related high pressure recirculation core damage events could be potentially mitigated (insufficient time to manually align a backup system on failure of injection for medium and large LOCAs). The estimated benefit is approximately 8% of MAB ($145.4K) or $11.6K. Since the cost of the proposed modification is judged to be greater than the MAB ($145.4K), the suggestion was screened out from further consideration.
124	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	(6), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
125	Install independent AC high pressure injection system	Would allow make up and feed and bleed capabilities during a SBO	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
126	Create the ability to manually align ECCS recirculation	Provides a backup should automatic or remote operation fail	(1), (12)	B	Since the proposed modification facilitates local operation of recirculation valves when remote operation fails, the risk reduction benefit of the proposed change was estimated by effectively reducing the recirculation MOV fail to transfer probability to zero (conservatively assuming that all remote failures can be recovered locally for small LOCA events). CDF was estimated to decrease by 1.6E-7 or by 1.6%. The benefit of the proposed change is estimated as <$2.4k (0.016*$145.4K). Since the cost of the proposed modification is judged to be much greater than the assessed benefit, the modification was screened out from further consideration. The capability for local operation exists, since recovery by local operation is considered in the PSA.
127	Implement a BWST makeup procedure	Decrease core damage frequency from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR	(12), (13)	B	ANO-1 already has guidance for injection from other water sources in the event of inadequate BWST level. The normal procedure is 1104.003 -- CHEMICAL ADDITION, Section 9.0 step 9.3 directs the use of Attachment L (Boric Acid and Condensate Addition to BWST (T-3)). Other means are: Procedure 1104.020 -- CLEAN WASTE SYSTEM OPERATION, Section 34.0 "BWST Fill From Clean Waste Receiver Tank (T-12A, B, C, D)"; Procedure 1104.006 -- SPENT FUEL COOLING SYSTEM, Section 12.0 "Spent Fuel Pool Level Reduction", Step 12.2 using P-40A or B aligned to the BWST and Step 12.3 using P-66 aligned to the BWST.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
128	Stop low pressure injection pumps earlier in medium or large LOCAs	Would give more time to perform recirculation swapover.	(13)	A	Not Applicable. ANO-1 procedures do not require that low pressure injection pumps be secured during medium or large LOCAs.
129	Emphasize timely recirc swapover in operator training	Reduce human error probability of recirculation failure	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
130	Upgrade CVCS to mitigate small LOCAs	For a plant like the AP600 where CVCS can't mitigate small LOCA, an upgrade would decrease CDF from small LOCA	(8)	A	Not applicable to ANO-1.
131	Install an active high pressure SI system	For a plant like the AP600, where an active high pressure injection system does not exist, would add redundancy in high pressure injection.	(8)	A	Not applicable to ANO-1.
132	Change "in-containment" BWST suction from 4 check valves to 2 check and 2 air operated valves	Remove common mode failure of all four injection paths	(8)	A	ANO-1 has a single suction line (that contains a locked open manual valve) from the BWST that results in a single failure vulnerability for the ECCS pumps. Review of the ANO-1 core damage results indicates that CDF could be reduced by 2.7E-8 (by 0.26%) if this single failure vulnerability was eliminated. Since the benefit of the change (approximately $400 or 0.26% of the MAB of $145.4K) is clearly much less than the associated cost this suggestion was screened out from further consideration.
133	Replace two of the four safety injection pumps with diesel pumps	Intended for System 80+, which has four trains of SI. This would reduce common cause failure probability.	(16), (17)	A	The maximum benefit for reducing core damage to zero is $145.4K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. ANO-1 has 2 LPSI pumps and 3 HPSI pumps but the conclusion remains the same.
134	Align LPCI or core spray to CST on loss of suppression pool cooling	Low pressure ECCS can be maintained in loss of suppression pool cooling scenarios	(10), (13)	A	Not Applicable to ANO-1. Applicable to BWR.
135	Raise HPCI/RCIC backpressure trip setpoints	Ensures HPCI/RCIC availability when high suppression pool temperatures exist.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
136	Improve the reliability of the ADS	Reduce frequency high pressure core damage sequences	(4)	A	Not Applicable to ANO-1. Applicable to BWR.
137	Disallow automatic vessel depressurization in non-ATWS scenarios	Improve operator control of plant.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
138	Create automatic swapover to recirculation on BWST depletion	Would remove human error contribution from recirculation failure.	(5), (6), (11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
139	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOP.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
140	Replace old air compressors with more reliable ones.	Improve reliability and increase availability of instrument air compressors.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
141	Install Nitrogen bottles as backup gas supply for SRVs	Extend operation of Safety Relief Valves during SBO and loss of air events (BWRs)	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
142	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
143	Add capability to remove power from the bus powering the control rods	Decrease time to insert control rods when if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
144	Create cross-connect ability for standby liquid control (SLC) trains	Improved reliability for boron injection during ATWS	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
145	Create an alternate boron injection capability (backup to SLC)	Improved reliability for boron injection during ATWS	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
146	Remove or allow override of LPCI injection during ATWS	On failure of HPCI and condensate, the Susquehanna units direct reactor depressurization followed by 5 minutes of automatic LPCI injection. Would allow control of LPCI immediately.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	Would improve equipment availability after an ATWS.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
148	Create a boron injection system to back up the mechanical control rods.	Provides a redundant means to shut down the reactor.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
149	Provide an additional I&C system (e.g., AMSAC).	Improve I&C redundancy and reduce ATWS frequency.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
150	Provide capability for remote operation of secondary side PORVs in SBO	Manual operation of these valves is required in a SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.	(2)	B	ANO-1 already has the ability and procedural guidance to take manual control of these valves by using a chain pulley from the elevation below.
151	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt injection.	(5), (6), (9), (11), (12), (13), (14), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
152	Make procedural changes only for the RCS depressurization option	Reduce RCS pressure without cost of a new system	(7), (9), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
153	Defeat 100% load rejection capability	Eliminates the possibility of a stuck open PORV after a LOP, since PORV opening wouldn't be needed	(13)	A	Not applicable to ANO-1 as ANO-1 does not have 100% load rejection capability.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
154	Change CRD flow control valve failure position	Change failure position to the 'fail-safest' position	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
155	Add secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
156	Digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	Reduced seismic CDF	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
158	Bolt MCC B-61 and B-62 together.	MCC B-61 and B-62 are next to each other, contain essential relays and are not bolted together.	(19)	B	The proposed modification has already been incorporated.
159	Confirm adequate anchorage for MCC B-21	Confirmation of adequate anchorage of MCC B-21 must be confirmed.	(19)	B	The proposed modification has already been incorporated.
160	File cabinets next to control cabinets C-47, C-54, C-28 must be secured to prevent them from toppling during an earthquake.	Control cabinets C-47, C-54, C-28 had unsecured file cabinets adjacent to them that could topple in an earthquake.	(19)	B	The proposed modification has already been incorporated.
161	EFIC Signal Conditioning Cabinets C-540A and C-540B must be bolted together.	EFIC Signal Conditioning Cabinets C-540A and C-540B are next to each other, contain essential relays and are not bolted together.	(19)	B	The proposed modification has already been incorporated.
162	Compressed oxygen bottle rack next to Control Cabinet C-27 must be secured.	Compressed oxygen bottle rack next to Control Cabinet C-27 is unsecured.	(19)	B	The proposed modification has already been incorporated.
163	Propane Tank T-70 must be anchored.	Propane Tank T-70, located approximately 15 feet from Condensate Storage Tank T-41, is not anchored.	(19)	B	The proposed modification has already been incorporated.
164	The angle frame around the cover plate for valves CV-2233, CV-2234, CV-2214 must be widened to accommodate more movement.	The angle frame around the cover plate for valves CV-2233, CV-2234, CV-2214 could interact with the valves during an earthquake.	(19)	B	The proposed modification has already been incorporated.
165	Adequate clearance for MOV CV-3851 must be verified	The valve hand wheel for MOV CV-3851 is within ¼" of a support and could be damaged in an earthquake.	(19)	B	The proposed modification has already been incorporated.
166	Additional flexibility in the power cable for CV-3850 must be provided.	The power cable for CV-3850 is taut between the valve and a support and could potentially pull out during an earthquake.	(19)	B	The proposed modification has already been incorporated.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
167	Further investigate the calculated value for HCLPF (<0.3g) for the Emergency Diesel Fuel Tanks (T-57A and T-57B)	The Emergency Diesel Fuel Tanks (T-57A and T-57B) have a calculated HCLPF value below 0.3g.	(19)	B	The proposed modification has already been incorporated.
168	Add scuppers to the parapet walls of the ANO1 roof structures to limit the amount of water that can build up.	Local, intense precipitation or Probable Maximum Precipitation (PMP) may create excessive roof loading due to ponding.	(19)	B	The proposed modification has already been incorporated.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
1	Cap downstream piping of normally closed ICW drain and vent valves	Reduces the frequency of loss of ICW initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Loss of ICW is included as part of the Loss of Power Conversion System initiating event. Analysis case ICW1 determined the benefit of eliminating all causes of this initiating event to be <$4K. The costs associated with the needed procedure changes and/or plant modifications required to implement this alternative are greater than the benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	Potential reduction in the probability of RCP seal failure.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4k (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
4	Additional training on the Loss of ICW	Potential improvement in success rate of operator actions after a loss of ICW.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4K (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
7	Increase makeup pump lube oil capacity	Would lengthen time before makeup pump failure due to lube oil overheating in loss of SW sequences	22.7%	21.5%	<$33k	>2 x Benefit	Screen out	Analysis case LOSWTOMU determined the benefit from eliminating all dependence of MU pumps on SW to be <$33k. In order to implement this alternative, hardware changes would be necessary to increase the oil capacity, add oil-air heat exchangers, increase room cooling capacity. Procedures would need to be modified. The combined cost of these changes will be greater than the benefit obtained. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	27.0%	Note 1	<$39.3k	>2 x Benefit	Screen out	The maximum benefit from a plant change that reduces the CDF due to SW failures to zero is estimated as approximately $39.3k (27% of MAB, as approximately 27% of CDF can be attributed to SW failures). The actual benefit is estimated as less than $39.3k, since loss of SW scenarios cannot be entirely eliminated by adding an additional pump. The cost of adding an additional service water pump is judged to be greater than this amount, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW or SBO.	23.6%	21.1%	<$33.4k	>2 x Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW, but not SBO.	23.6%	21.1%	<$33.4k	>2 x Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
12	Use existing hydro test pump for RCP seal injection	Independent seal injection source, without cost of a new system	23.6%	21.1%	<$33.4k	> Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. (There is no onsite hydro pump with the necessary capacity, a permanent plant modification would be required to allow the pump to be aligned in the time window available, and procedure changes implemented to direct that it be aligned, and it is judged that this would cost more than $33.4k). This SAMA would yield no additional benefit from considering external events because the RCPs would be stopped in the event of an external initiator and no cooling is required to the RCP seals if they are stopped. Not cost-beneficial; cost is expected to exceed the benefit.
15	Add a third ICW pump	Reduce chance of loss of ICW leading to RCP seal LOCA	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case ICW2 determined the benefit of adding an additional pump in parallel with the existing "B" pump to be <$1.1K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly higher than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
16	Prevent makeup pump flow diversion from the relief valves	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling.	0.5%	Note 1	<$0.8k	>2 x Benefit	Screen out	HPI RV failures are not modeled as a failure mode in the ANO-1 model. This is judged to be NA at ANO-1 (makeup pump capacity sufficient to continue to supply seal injection in the unlikely event that a RV spuriously lifts). The ANO-1 PSA does consider a diversion of flow to the makeup tank. Eliminating this diversion path was estimated to reduce CDF by 5.1E-8 (0.5%) which translates to a benefit of approximately $0.7k (0.5% of the MAB of $145.4k). It is concluded that the risk benefit attained does not justify the cost of the proposed modification). Not cost-beneficial; cost is expected to exceed twice the benefit.
18	Procedures to stagger HPI pump use after a loss of SW	Allow high pressure injection to be extended after a loss of SW	5.4%	Note 1	<$7.9k	>2 x Benefit	Screen out	This suggestion was previously evaluated and discarded as overly burdensome and restrictive on operations. (Suggested change also screens as not cost-effective, since core damage is normally only delayed rather than averted. Since SW contribution is approximately 27% of core damage, and since SW core damage may be decreased by about 10% - 20% by the proposed change (more time available to restore SW) it was estimated that CDF might be reduced by 2.7% - 5.4% which suggests a value of the proposed change of approximately $7.9k (5.4% of MAB) which does not justify the expense of the proposed change. Not cost-beneficial; cost is expected to exceed twice the benefit.
20	Procedural guidance for use of cross-tied ICW or SW pumps	Can reduce the frequency of the loss of either of these.	2.7%	Note 1	<$4k	>2 x Benefit	Screen out	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.
21	Procedure & training enhancements in support system failure sequences	Potential improvement in success rate of operator actions after support system failures due to more procedural guidance on anticipating problems and coping.	2.7%	Note 1	<$4k	>2 x Benefit	Screen out	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
22	Improve ability to cool RHR heat exchangers	Reduced chance of loss of DHR by 1)Performing procedure and hardware modification to allow manual alignment of fire protection system to the ICW system, or 2)Installing an ICW header cross-tie	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	ANO-1 already has significant crosstie capability in the SW system (e.g., the ability to supply cooling to either RHR heat exchanger from a particular SW pump). Per #3 (case ICW1) above, no cost-effective procedure changes were identified which would significantly reduce the SW CDF. Not cost-beneficial; cost is expected to exceed twice the benefit.
25	Procedures for temporary HVAC	Provides for improved credit to be taken for loss of HVAC sequences	0.1%	0.4%	<$0.2k	>2 x Benefit	Screen out	Analysis case DGHVAC determined the benefit of eliminating the diesel generator dependency on HVAC to be <$0.2k. The cost associated with developing a procedure for temporary HVAC combined with the purchase of the temporary equipment are significantly greater than the assessed benefit. Therefore the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
31	Develop an enhanced drywell spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (The pre-construction cost for such a system was estimated as ~$1.5M for System 80). Not cost-beneficial; cost is expected to exceed twice the benefit.
32	Provide a dedicated existing drywell spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
34	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA); $10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
35	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA)) This SAMA could result in an inadvertent unfiltered release and thus could increase public risk. Not cost-beneficial; cost is expected to exceed twice the benefit.
36	Create/enhance hydrogen igniters with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $6.1M (TVA, 1994); $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
37	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $780k (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $108M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
39	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $18M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
42	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $8.75M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
43.2	Creating other options for reactor cavity flooding (Part b)	(b)Flood cavity via systems such as diesel driven fire pumps	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Note that this is either not feasible or prohibitively expensive with ANO-1 design, since reactor cavity flooding is not possible due to the open door at the bottom of the incore tunnel. This allows water to flow to the lower containment and be used for recirculation. Not cost-beneficial; cost is expected to exceed twice the benefit.
45	Provide a core debris control system	(Intended for ice-condenser plants): Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
46	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
47	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $10.9M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
48	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Boron dilution impact would require evaluation). Not cost-beneficial; cost is expected to exceed twice the benefit.
49	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
51	Increase containment design pressure	Reduce chance of containment overpressure	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	Prevent basemat melt through	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
53	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
54	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost >$10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
55	Add ribbing to the containment shell	Would reduce the chance of buckling of containment under reverse pressure loading.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
56	Reactor Building Liner Protective Barrier	A protective barrier inside the incore instrument tunnel or along the reactor building liner just beyond the tunnel could prevent certain types of containment failure, which could result in a notable reduction in the large release frequency.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
57	Train operations crew for response to inadvertent actuation signals	Improves chances of a successful response to the loss of two 120V AC buses, which causes inadvertent signals.	1.1%	0.4%	<$1.5k	>2 x Benefit	Screen out	Analysis case SPURIOUS determined the benefit of eliminating all spurious SI and low pressurizer pressure signals to be <$1.5k. The costs of providing additional training significantly exceed the benefit to be gained. [Operation procedures 1203.36 DC(Loss of 125 V DC), 1203.37 (Abnormal ES Bus Voltage), and 1203.46 (Loss of Load Center) are available to provide operator guidance for loss of a vital AC or vital DC bus.] Not cost-beneficial; cost is expected to exceed twice the benefit.
60	Provide additional DC battery capability	Would ensure longer battery capability during a SBO, reducing frequency of long term SBO sequences.	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
63	Improved bus cross tie ability	Improved AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with providing additional crosstie capability are judged to be significantly greater than the benefit that would be achieved. (ANO-1 has the ability to cross tie buses from red to green train in order to ensure an adequate power supply.) Not cost-beneficial; cost is expected to exceed twice the benefit.
64	Alternate battery charging capability	Improved DC power reliability. Either cross tie of AC buses, or a portable diesel-driven battery charger.	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $107k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
66	Replace batteries	Improved reliability	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
67	Create AC power cross tie capability across units at a multi-unit site	Improved AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	1.2%	0.5%	<$0.9k	>2 x Benefit	Screen out	Analysis case BREAKER removed all bus infeed, cross-tie, and diesel generator output breakers from the fault tree model. This simulates having perfectly reliable circuit breakers. The benefit shown in this case is <$1k. The cost of developing procedures and purchasing spare breakers is greater than the benefit. When spare breakers are on hand, existing procedures can be used to set up the circuit breakers for use in an emergency. (ANO-1procedure 1107.002 exists to provide guidance to swap breakers for 4160V during an emergency). Not cost-beneficial; cost is expected to exceed twice the benefit.
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with procedural and training enhancements are greater than this amount. Not cost-beneficial; cost is expected to exceed twice the benefit.
73	Install gas turbine generators	Improve on-site AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
74	Install tornado protection on gas turbine generator	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	ANO-1 has already installed backup power capability that has reduced loss of offsite power to a negligible contributor to ANO-1 risk. Analysis case NO-LOSP indicates a maximum benefit of <$1.1k for a modification which further improves the AC reliability. Not cost-beneficial; cost is expected to exceed twice the benefit.
75	Create a river water backup for diesel cooling.	Provides redundant source of diesel cooling.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
76	Use firewater as a backup for diesel cooling	Redundancy in diesel support systems	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
77	Provide a connection to alternate offsite power source	Increase offsite power redundancy	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
78	Implement underground offsite power lines	Could improve offsite power reliability, particularly during severe weather.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
81	Install a redundant spray system to depressurize the primary system during a SGTR.	Enhanced depressurization ability during SGTR.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (See also item #151) (Estimated cost $5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
82	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (ANO-1 already has N-16 monitors as well as alternative means for evaluating SGTR events. (Estimated cost $9.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	(a)A highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources, (b)a system which returns the discharge from the steam generator relief valve back to the primary containment, (c)an increased pressure capability on the steam generator shell side with corresponding increase in the safety valve setpoints.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (Option a would have some benefit for non SGTR sequences, but would clearly cost much more than the ANO-1 MAB of $226K). Not cost-beneficial; cost is expected to exceed twice the benefit.
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
85	Replace steam generators with new design	Lower frequency of SGTR	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
87	Direct steam generator flooding after a SGTR, prior to core damage.	Would provide for improved scrubbing of SGTR releases.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	No impact on CDF, but release can be reduced if ruptured SG tubes are kept covered. New guidance from the Owner's Group is being incorporated into the EOPs. Both steam generators are used for heat removal following a SGTR to provide natural circulation cooling if offsite power is lost. Can flood if necessary, but may not help depending on location of tube failure, cannot flood to where level may impact the turbine driven pump. No further action is required. Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k and only a fraction of this benefit would be achieved if this suggestion were implemented. Since the assessed benefit is much less than the estimated cost this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	Reduce chances of tube rupture	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k (and not all tube ruptures would be eliminated by expanding the inspection scope). The costs required to implement this suggestion are therefore judged to be significantly greater than the benefit achieved. (Estimated cost $1.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
89	Locate RHR inside of containment	Would prevent ISLOCA out the RHR pathway	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per the ANO-1 PSA (Analysis case ISL) minimal benefit is attainable even if the proposed change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Since the cost of the proposed modification is many orders of magnitude greater than the assessed benefit, the proposed SAMA is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.
90	Provide self-actuating containment isolation valves	For plants that don't have this, it would reduce the frequency of isolation failure	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
92	Increase frequency of valve leak testing	Decrease ISLOCA frequency	~0%	~0.4%	<$0.2k	>2 x Benefit	Screen out	Since ANO-1 has pressure detectors between the first two pressure isolation valves for the dominant ISLOCA scenarios (see #91 above), it is judged that ISLOCA frequency would not be significantly reduced by the proposed modification. Therefore the benefit of the suggested modification is estimated as less than 10% of a change which would eliminate ISLOCA scenarios. The value of the change is then estimated as less than $160 (10% of the benefit from analysis case ISL). Since the cost of increased testing is much more than the assessed benefit the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
93	Improve operator training on ISLOCA coping	Decrease ISLOCA effects	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
94	Install relief valves in the ICW system	Would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA	~0%	~0%	<$0.2k	>2 x Benefit	Screen out	This scenario was estimated as 3E-9 contributor to core damage and containment bypass core damage in the ANO-1 ISLOCA analysis. The value of the change is estimated as a 6.7% reduction in ISLOCA frequency. Per the ANO-1 PSA (analysis case ISL) the value of the risk reduction is estimated as approximately $103 (0.067*$1600). Since the cost of the proposed modification is much greater than the assessed benefit, the proposed modification was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
95	Provide leak testing of valves in ISLOCA paths	At Kewaunee, four MOVs isolating RHR from the RCS were not leak tested. Will help reduce ISLOCA frequency	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
96	Revise EOPs to improve ISLOCA identification	Salem had a scenario in which an RHR ISLOCA could direct initial leakage back to the PRT, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per the ANO-1 PSA (analysis case ISL) minimal benefit is attainable even if the training/procedure change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Therefore the proposed suggestion is screened out as not cost-effective. Not cost-beneficial; cost is expected to exceed twice the benefit.
97	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Analysis case ISL determined the benefit of eliminating all ISLOCA to be $1,600. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
98	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	0.4%	100.0%	<$24k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction, $24K if ISLOCA frequency was assumed to be significantly decreased; see analysis case ISL). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
107	Install digital feedwater upgrade	Reduces chance of loss of MFW following a plant trip.	3.2%	0.6%	<$4.1k	>2 x Benefit	Screen out	Analysis case FW determined the benefit of eliminating all feedwater initiators (Loss of power conversion system and excessive feedwater flow) to be <$4.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	1.0%	4.3%	<$2.3k	>2 x Benefit	Screen out	Analysis case PDSTDPDC estimated the risk reduction benefit of this suggested change as <$2.3k. Station Blackout is already a negligible contributor to ANO-1 core damage risk due to installation of a diverse backup DG. Since the cost of the suggested change is judged to be much greater than the assessed benefit the change was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
115	Add a motor train of AFW to the steam trains.	For PWRs that do not have any motor trains of AFW, this can increase reliability in non-SBO sequences.	Note 2	Note 2	<MAB	>2MAB	Screened out	Cost of adding another motor driven AFW train would be expected to exceed 2 MAB. ANO-1 already has a motor driven pump in combination with a turbine driven pump. Not cost-beneficial; cost is expected to exceed twice the benefit.
121	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	Note 2	Note 2	<MAB	>2MAB	Screen out	The maximum benefit for reducing core damage to zero is $145.4k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
124	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	42.0%	Note 1	<$61.1k	>2 x Benefit	Screen out	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. (Estimated cost $2.2M (System 80+), $3.5M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
125	Install independent AC high pressure injection system	Would allow make up and feed and bleed capabilities during a SBO	42.0%	Note 1	<$61.1k	>2 x Benefit	Screen out	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. Not cost-beneficial; cost is expected to exceed twice the benefit.
129	Emphasize timely recirc swapover in operator training	Reduce human error probability of recirculation failure	<37.1%	<6.8%	<$47.2k, possibly as low as <$31.5k	<2 x Benefit	This SAMA does not screen out.	Per analysis case PDSHPROA the benefit of a change that reduced the human error probability for recirculation to zero was estimated as $47.2k. If increased training is assumed to reduce the human error probability by a factor of 3, then the benefit of increased training would be estimated as $31.5K (47.2k * 2/3). The proposed suggestion does not screen out.
138	Create automatic swapover to recirculation on BWST depletion	Would remove human error contribution from recirculation failure.	37.1%	6.8%	<$47.2k	>2 x Benefit	Screen out	Per analysis case PDSHPROA the benefit of this proposed modification was estimated as $47.2k. The engineering, procurement and installation of controls to automate the swapover of BWST to recirc from the sump would include BWST level monitors, ESFAS upgrade and interlock controls on sump and BWST valves. These changes in addition to operational procedure changes and training would well exceed 2 X $47.2k (assume internal and external effects). No cost estimate needed. Not cost-beneficial; cost is expected to exceed twice the benefit.
139	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOP.	0.7%	7.0%	<$2.5k	>2 x Benefit	Screen out	Analysis case INSTAIR2 removed all power dependencies/support for the air compressors. The benefit was determined to be <$2.5k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
140	Replace old air compressors with more reliable ones.	Improve reliability and increase availability of instrument air compressors.	0.9%	9.4%	<$3.4k	>2 x Benefit	Screen out	Analysis case INSTAIR1 determined the benefit of perfectly reliable air compressors to be <$3.4k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
142	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
143	Add capability to remove power from the bus powering the control rods	Decrease time to insert control rods when if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. (Estimated cost $143k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	Would improve equipment availability after an ATWS.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
148	Create a boron injection system to back up the mechanical control rods.	Provides a redundant means to shut down the reactor.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
149	Provide an additional I&C system (e.g., AMSAC).	Improve I&C redundancy and reduce ATWS frequency.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
151	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt injection.	1.8%	18.1%	<$6.4k	>2 x Benefit	Screen out	Analysis case PDSRCD evaluated the benefit attained if perfect depressurization capability is provided to be $6.4k. (Since ANO-1has high head ECCS pumps, depressurization is only required for SGTR sequences). Since the cost of the proposed change would cost much more than the assessed benefit the change is screened out from further consideration. (Estimated cost for new system $4.6M (TVA), $500k to enhance existing system (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
152	Make procedural changes only for the RCS depressurization option	Reduce RCS pressure without cost of a new system	1.8%	18.1%	<$6.4k	>2 x Benefit	Screen out	A sensitivity run assuming perfect depressurization capability indicates that negligible value (<$6.4k) is attained by revising the SGTR procedure to credit additional depressurization methods (see #151, case PDSRCD). Therefore the cost of a significant EOP change is not justified by the risk reduction attained. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
155	Add secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	~0%	~0%	~$0	>2 x Benefit	Screen out	Analysis case NOSLB determined the benefit of eliminating all steam/feedwater line breaks to be negligible. Since the cost of the proposed change is much greater than the risk reduction benefit attained the suggestion was screened out from further consideration. (Estimated cost $1.1M (System 80)). Not cost-beneficial; cost is expected to exceed twice the benefit.
156	Add digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	34.4%	5.9%	<$43.6k	>2 x Benefit	Screen out	Analysis case NO-A determined the benefit of eliminating all Large Break LOCA initiators to be <$43.6K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	Reduced seismic CDF	Note 2	Note 2	<MAB	>2 MAB	Screen out	The benefit achieved is estimated as less than the ANO-1 MAB of $145.4K. (Seismic CDF is judged to have a CDF significantly less than the internal CDF). ANO-1 has performed an analysis to determine that the existing plant design (SSE = 0.2g) is adequate for a 0.3g earthquake. This analysis cost ~$750k. It is expected that significant plant modifications would be necessary to increase the capacity to 0.4g and that the cost would greatly exceed 2MAB. Not cost-beneficial; cost is expected to exceed twice the benefit.

Note 1 Reduction in CDF estimated as a percentage reduction therefore reduction in person-rem was not directly calculated.

Note 2 Reduction in CDF was not estimated because the cost is expected to be much greater that MAB and the item was screened.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
1	Cap downstream piping of normally closed ICW drain and vent valves	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Loss of ICW is included as part of the Loss of Power Conversion System initiating event. Analysis case ICW1 determined the benefit of eliminating all causes of this initiating event to be <$4K. The costs associated with the needed procedure changes and/or plant modifications required to implement this alternative are greater than the benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4k (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
4	Additional training on the Loss of ICW	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4K (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.

5 The value of the "benefit" considered in this column is the baseline value.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
7	Increase makeup pump lube oil capacity	<$33k	>2 x Benefit	Screen out	<$66k	<$50.9k	<$36.2k	<$53.2k	<$14.6k	Analysis case LOSWTOMU determined the benefit from eliminating all dependence of MU pumps on SW to be <$33k. In order to implement this alternative, hardware changes would be necessary to increase the oil capacity, add oil-air heat exchangers, increase room cooling capacity. Procedures would need to be modified. The combined cost of these changes will be greater than the benefit obtained. Not cost-beneficial; cost is expected to exceed twice the benefit.
9	Provide additional SW pump	<$39.3k	>2 x Benefit	Screen out	<$78.6k	<=$61.2k	<$43.7k	<$64.2k	<$17.7k	The maximum benefit from a plant change that reduces the CDF due to SW failures to zero is estimated as approximately $39.3k (27% of MAB, as approximately 27% of CDF can be attributed to SW failures). The actual benefit is estimated as less than $39.3k, since loss of SW scenarios cannot be entirely eliminated by adding an additional pump. The cost of adding an additional service water pump is judged to be greater than this amount, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
12	Use existing hydro test pump for RCP seal injection	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. (There is no onsite hydro pump with the necessary capacity, a permanent plant modification would be required to allow the pump to be aligned in the time window available, and procedure changes implemented to direct that it be aligned, and it is judged that this would cost more than $33.4k). This SAMA would yield no additional benefit from considering external events because the RCPs would be stopped in the event of an external initiator and no cooling is required to the RCP seals if they are stopped. Not cost-beneficial; cost is expected to exceed the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
15	Add a third ICW pump	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.1k	<$1.6k	<$0.6k	Analysis case ICW2 determined the benefit of adding an additional pump in parallel with the existing "B" pump to be <$1.1K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly higher than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
16	Prevent makeup pump flow diversion from the relief valves	<$0.8k	>2 x Benefit	Screen out	<$1.5k	<=$1.2k	<$0.9k	<$1.2k	<$0.4k	HPI RV failures are not modeled as a failure mode in the ANO-1 model. This is judged to be NA at ANO-1 (makeup pump capacity sufficient to continue to supply seal injection in the unlikely event that a RV spuriously lifts). The ANO-1 PSA does consider a diversion of flow to the makeup tank. Eliminating this diversion path was estimated to reduce CDF by 5.1E-8 (0.5%) which translates to a benefit of approximately $0.7k (0.5% of the MAB of $145.4k). It is concluded that the risk benefit attained does not justify the cost of the proposed modification). Not cost-beneficial; cost is expected to exceed twice the benefit.
18	Procedures to stagger HPI pump use after a loss of SW	<$7.9k	>2 x Benefit	Screen out	<$15.8k	<=$12.3k	<$8.8k	<$12.9k	<$3.6k	This suggestion was previously evaluated and discarded as overly burdensome and restrictive on operations. (Suggested change also screens as not cost-effective, since core damage is normally only delayed rather than averted. Since SW contribution is approximately 27% of core damage, and since SW core damage may be decreased by about 10% - 20% by the proposed change (more time available to restore SW) it was estimated that CDF might be reduced by 2.7% - 5.4% which suggests a value of the proposed change of approximately $7.9k (5.4% of MAB) which does not justify the expense of the proposed change. Not cost-beneficial; cost is expected to exceed twice the benefit.
20	Procedural guidance for use of cross-tied ICW or SW pumps	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.2k	<$4.4k	<$6.5k	<$1.8k	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
21	Procedure & training enhancements in support system failure sequences	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.2k	<$4.4k	<$6.5k	<$1.8k	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.
22	Improve ability to cool RHR heat exchangers	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	ANO-1 already has significant crosstie capability in the SW system (e.g, the ability to supply cooling to either RHR heat exchanger from a particular SW pump). Per #3 (case ICW1) above, no cost-effective procedure changes were identified which would significantly reduce the SW CDF. Not cost-beneficial; cost is expected to exceed twice the benefit.
25	Procedures for temporary HVAC	<$0.2k	>2 x Benefit	Screen out	<$0.4k	<=$0.3k	<$0.2k	<$0.3k	<$0.1k	Analysis case DGHVAC determined the benefit of eliminating the diesel generator dependency on HVAC to be <$0.2k. The cost associated with developing a procedure for temporary HVAC combined with the purchase of the temporary equipment are significantly greater than the assessed benefit. Therefore the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
31	Develop an enhanced drywell spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (The pre-construction cost for such a system was estimated as ~$1.5M for System 80). Not cost-beneficial; cost is expected to exceed twice the benefit.
32	Provide a dedicated existing drywell spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
34	Install a filtered containment vent to remove decay heat	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA); $10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
35	Install an unfiltered hardened containment vent	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA)) This SAMA could result in an inadvertent unfiltered release and thus could increase public risk. Not cost-beneficial; cost is expected to exceed twice the benefit.
36	Create/enhance hydrogen igniters with independent power supply.	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $6.1M (TVA, 1994); $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
37	Create a passive hydrogen ignition system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $780k (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $108M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
39	Create a water cooled rubble bed on the pedestal	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $18M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
42	Create a reactor cavity flooding system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $8.75M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
43.2	Creating other options for reactor cavity flooding (Part b)	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Note that this is either not feasible or prohibitively expensive with ANO-1 design, since reactor cavity flooding is not possible due to the open door at the bottom of the incore tunnel. This allows water to flow to the lower containment and be used for recirculation. Not cost-beneficial; cost is expected to exceed twice the benefit.
45	Provide a core debris control system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
46	Create a core melt source reduction system (COMSORS)	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
47	Provide containment inerting capability	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $10.9M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
48	Use fire water spray pump for containment spray	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Boron dilution impact would require evaluation). Not cost-beneficial; cost is expected to exceed twice the benefit.
49	Install a passive containment spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
51	Increase containment design pressure	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivty) (Bounding)	Benefit (15% Discount Rate Sensitivty) (Bounding)	Basis for Conclusion
53	Provide a reactor vessel exterior cooling system.	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
54	Create another building, maintained at a vacuum to be connected to containment	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost >$10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
55	Add ribbing to the containment shell	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
56	Reactor Building Liner Protective Barrier	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
57	Train operations crew for response to inadvertent actuation signals	<$1.5k	>2 x Benefit	Screen out	<$3k	<=$2.4k	<$1.7k	<$2.5k	<$0.6k	Analysis case SPURIOUS determined the benefit of eliminating all spurious SI and low pressurizer pressure signals to be <$1.5k. The costs of providing additional training significantly exceed the benefit to be gained. [Operation procedures 1203.36 DC(Loss of 125 V DC), 1203.37 (Abnormal ES Bus Voltage), and 1203.46 (Loss of Load Center) are available to provide operator guidance for loss of a vital AC or vital DC bus.] Not cost-beneficial; cost is expected to exceed twice the benefit.
60	Provide additional DC battery capability	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
61	Use fuel cells instead of lead-acid batteries	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
63	Improved bus cross tie ability	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with providing additional crosstie capability are judged to be significantly greater than the benefit that would be achieved. (ANO-1 has the ability to cross tie buses from red to green train in order to ensure an adequate power supply.) Not cost-beneficial; cost is expected to exceed twice the benefit.
64	Alternate battery charging capability	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $107k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
66	Replace batteries	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
67	Create AC power cross tie capability across units at a multi-unit site	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
69	Develop procedures to repair or change out failed 4KV breakers	<$0.9k	>2 x Benefit	Screen out	<$1.8k	<=$1.4k	<$1k	<$1.5k	<$0.5k	Analysis case BREAKER removed all bus infeed, cross-tie, and diesel generator output breakers from the fault tree model. This simulates having perfectly reliable circuit breakers. The benefit shown in this case is <$1k. The cost of developing procedures and purchasing spare breakers is greater than the benefit. When spare breakers are on hand, existing procedures can be used to set up the circuit breakers for use in an emergency. (ANO-1procedure 1107.002 exists to provide guidance to swap breakers for 4160V during an emergency). Not cost-beneficial; cost is expected to exceed twice the benefit.
70	Emphasize steps in recovery of offsite power after a SBO.	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with procedural and training enhancements are greater than this amount. Not cost-beneficial; cost is expected to exceed twice the benefit.
73	Install gas turbine generators	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
74	Install tornado protection on gas turbine generator	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	ANO-1 has already installed backup power capability that has reduced loss of offsite power to a negligible contributor to ANO-1 risk. Analysis case NO-LOSP indicates a maximum benefit of <$1.1k for a modification which further improves the AC reliability. Not cost-beneficial; cost is expected to exceed twice the benefit.
75	Create a river water backup for diesel cooling.	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
76	Use firewater as a backup for diesel cooling	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
77	Provide a connection to alternate offsite power source	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
78	Implement underground offsite power lines	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
81	Install a redundant spray system to depressurize the primary system during a SGTR.	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (See also item #151) (Estimated cost $5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
82	Improved SGTR coping abilities	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (ANO-1 already has N-16 monitors as well as alternative means for evaluating SGTR events. (Estimated cost $9.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (Option a would have some benefit for non SGTR sequences, but would clearly cost much more than the ANO-1 MAB of $226K). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
85	Replace steam generators with new design	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
87	Direct steam generator flooding after a SGTR, prior to core damage.	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	No impact on CDF, but release can be reduced if ruptured SG tubes are kept covered. New guidance from the Owner's Group is being incorporated into the EOPs. Both steam generators are used for heat removal following a SGTR to provide natural circulation cooling if offsite power is lost. Can flood if necessary, but may not help depending on location of tube failure, cannot flood to where level may impact the turbine driven pump. No further action is required. Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k and only a fraction of this benefit would be achieved if this suggestion were implemented. Since the assessed benefit is much less than the estimated cost this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k (and not all tube ruptures would be eliminated by expanding the inspection scope). The costs required to implement this suggestion are therefore judged to be significantly greater than the benefit achieved. (Estimated cost $1.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
89	Locate RHR inside of containment	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per the ANO-1 PSA (Analysis case ISL) minimal benefit is attainable even if the proposed change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Since the cost of the proposed modification is many orders of magnitude greater than the assessed benefit, the proposed SAMA is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
90	Provide self-actuating containment isolation valves	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
92	Increase frequency of valve leak testing	<$0.2.k	>2 x Benefit	Screen out	<$0.4k	<=$0.2.k	<$0.2k	<$0.3k	<$0.1k	Since ANO-1 has pressure detectors between the first two pressure isolation valves for the dominant ISLOCA scenarios (see #91 above), it is judged that ISLOCA frequency would not be significantly reduced by the proposed modification. Therefore the benefit of the suggested modification is estimated as less than 10% of a change which would eliminate ISL scenarios. The value of the change is then estimated as less than $160 (10% of the benefit from analysis case ISL). Since the cost of increased testing is much more than the assessed benefit the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
93	Improve operator training on ISLOCA coping	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
94	Install relief valves in the ICW system	<$0.2k	>2 x Benefit	Screen out	<$0.3k	<=$0.2k	<$0.2k	<$0.2k	<$0.1k	This scenario was estimated as 3E-9 contributor to core damage and containment bypass core damage in the ANO-1 ISLOCA analysis. The value of the change is estimated as a 6.7% reduction in ISLOCA frequency. Per the ANO-1 PSA (analysis case ISL) the value of the risk reduction is estimated as approximately $103 (0.067*$1600). Since the cost of the proposed modification is much greater than the assessed benefit, the proposed modification was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
95	Provide leak testing of valves in ISLOCA paths	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
96	Revise EOPs to improve ISLOCA identification	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per the ANO-1 PSA (analysis case ISL) minimal benefit is attainable even if the training/procedure change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Therefore the proposed suggestion is screened out as not cost-effective. Not cost-beneficial; cost is expected to exceed twice the benefit.
97	Ensure all ISLOCA releases are scrubbed	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Analysis case ISL determined the benefit of eliminating all ISLOCA to be $1,600. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
98	Add redundant and diverse limit switch to each containment isolation valve.	<$24k	>2 x Benefit	Screen out	<$48k	<=$24.2k	<$23.9k	<$33.4k	<$13.9k	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction, $24K if ISLOCA frequency was assumed to be significantly decreased; see analysis case ISL). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
107	Install digital feedwater upgrade	<$4.1k	>2 x Benefit	Screen out	<$8.2k	<=$6.7k	<$4.6k	<$6.8k	<$1.8k	Analysis case FW determined the benefit of eliminating all feedwater initiators (Loss of power conversion system and excessive feedwater flow) to be <$4.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	<$2.3k	>2 x Benefit	Screen out	<$4.6k	<=$3k	<$2.4k	<$3.5k	<$1.2k	Analysis case PDSTDPDC estimated the risk reduction benefit of this suggested change as <$2.3k. Station Blackout is already a negligible contributor to ANO-1 core damage risk due to installation of a diverse backup DG. Since the cost of the suggested change is judged to be much greater than the assessed benefit the change was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
115	Add a motor train of AFW to the steam trains.	<MAB	>2MAB	Screened out	<MAB	<MAB	<MAB	<MAB	<MAB	Cost of adding another motor driven AFW train would be expected to exceed 2 MAB. ANO-1 already has a motor driven pump in combination with a turbine driven pump. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
121	Create passive secondary side coolers	<MAB	>2MAB	Screened out	<MAB	<MAB	<MAB	<MAB	<MAB	The maximum benefit for reducing core damage to zero is $145.4k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
124	Provide an additional high pressure injection pump with independent diesel	<$61.1k	>2 x Benefit	Screen out	<$122.2k	<=$95.2k	<$67.9k	<$99.8k	<$27.5k	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. (Estimated cost $2.2M (System 80+), $3.5M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
125	Install independent AC high pressure injection system	<$61.1k	>2 x Benefit	Screen out	<$122.2k	<=$95.2k	<$67.9k	<$99.8k	<$27.5k	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. Not cost-beneficial; cost is expected to exceed twice the benefit.
129	Emphasize timely recirc swapover in operator training	<$47.2k, possibly as low as <$31.5k	<2 x Benefit	This SAMA does not screen out.	<$94.4k, possibly as low as <$62.9k	<$77.2k, possibly as low as <$51.5k	<$53.2k, possibly as low as <$35.5k	<$78.7k, possibly as low as <$52.5k	<$20.3k, possibly as low as <$13.6k	Per analysis case PDSHPROA the benefit of a change that reduced the human error probability for recirculation to zero was estimated as $47.2k. If increased training is assumed to reduce the human error probability by a factor of 3, then the benefit of increased training would be estimated as $31.5K (47.2k * 2/3). The proposed suggestion does not screen out.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
138	Create automatic swapover to recirculation on BWST depletion	<$47.2k	>2 x Benefit	Screen out	<$94.4k	<=$77.2k	<$53.2k	<$78.7k	<$20.3k	Per analysis case PDSHPROA the benefit of this proposed modification was estimated as $47.2k. The engineering, procurement and installation of controls to automate the swapover of BWST to recirc from the sump would include BWST level monitors, ESFAS upgrade and interlock controls on sump and BWST valves. These changes in addition to operational procedure changes and training would well exceed 2 X $47.2k (assume internal and external effects). No cost estimate needed. Not cost-beneficial; cost is expected to exceed twice the benefit.
139	Modify EOPs for ability to align diesel power to more air compressors.	<$2.5k	>2 x Benefit	Screen out	<$5k	<=$3.1k	<$2.6k	<$3.7	<$1.3k	Analysis case INSTAIR2 removed all power dependencies/support for the air compressors. The benefit was determined to be <$2.5k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
140	Replace old air compressors with more reliable ones.	<$3.4k	>2 x Benefit	Screen out	<$6.8k	<=$4.1k	<$3.5k	<$5k	<$1.8k	Analysis case INSTAIR1 determined the benefit of perfectly reliable air compressors to be <$3.4k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
142	Install MG set trip breakers in control room	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
143	Add capability to remove power from the bus powering the control rods	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. (Estimated cost $143k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
148	Create a boron injection system to back up the mechanical control rods.	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
149	Provide an additional I&C system (e.g., AMSAC).	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
151	Create/enhance reactor coolant system depressurization ability	<$6.4k	>2 x Benefit	Screen out	<$12.8k	<=$7.9k	<$6.7k	<$9.5k	<$3.4k	Analysis case PDSRCD evaluated the benefit attained if perfect depressurization capability is provided to be $6.4k. (Since ANO-1has high head ECCS pumps, depressurization is only required for SGTR sequences). Since the cost of the proposed change would cost much more than the assessed benefit the change is screened out from further consideration. (Estimated cost for new system $4.6M (TVA), $500k to enhance existing system (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
152	Make procedural changes only for the RCS depressurization option	<$6.4k	>2 x Benefit	Screen out	<$12.8k	<=$7.9k	<$6.7k	<$9.5k	<$3.4k	A sensitivity run assuming perfect depressurization capability indicates that negligible value (<$6.4k) is attained by revising the SGTR procedure to credit additional depressurization methods (see #151, case PDSRCD). Therefore the cost of a significant EOP change is not justified by the risk reduction attained. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
155	Add secondary side guard pipes up to the MSIVs.	~$0	>2 x Benefit	Screen out	~$0	~$0	~$0	~$0	~$0	Analysis case NOSLB determined the benefit of eliminating all steam/feedwater line breaks to be negligible. Since the cost of the proposed change is much greater than the risk reduction benefit attained the suggestion was screened out from further consideration. (Estimated cost $1.1M (System 80)). Not cost-beneficial; cost is expected to exceed twice the benefit.
156	Add digital large break LOCA protection	<$43.6k	>2 x Benefit	Screen out	<$87.2k	<=$71.5k	<$49.2k	<$72.8k	<$18.7k	Analysis case NO-A determined the benefit of eliminating all Large Break LOCA initiators to be $43.6K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	<MAB	>2 MAB	Screen out	<MAB	<MAB	<MAB	<MAB	<MAB	The benefit achieved is estimated as less than the ANO-1 MAB of $145.4K. (Seismic CDF is judged to have a CDF significantly less than the internal CDF). ANO-1 has performed an analysis to determine that the existing plant design (SSE = 0.2g) is adequate for a 0.3g earthquake. This analysis cost ~$750k. It is expected that significant plant modifications would be necessary to increase the capacity to 0.4g and that the cost would greatly exceed 2MAB. Not cost-beneficial; cost is expected to exceed twice the benefit.

G.3 ACRONYMS USED IN ATTACHMENT G

AAC	Alternate Alternating Current
ABB	Asea Brown Boveri, Inc.
AC	Alternating Current
ADS	Automatic Depressurization System
AFW	Auxiliary Feedwater
AFWST	Auxiliary Feedwater Storage Tank
AMSAC	ATWS Mitigating System Actuation Circuitry
ANO-1	Arkansas Nuclear One Unit 1
AOV	Air Operated Valve
ATWS	Anticipated Transient Without Scram
B&W	Babcock and Wilcox
BGE	Baltimore Gas and Electric Company
BWR	Boiling Water Reactor
BWST	Borated Water Storage Tank
CCNP	Calvert Cliffs Nuclear Plant
CCW	Component Cooling Water
CDF	Core Damage Frequency
CE	Combustion Engineering
CRD	Control Rod Drive
CST	Condensate Storage Tank
CV	Control Valve
CVCS	Chemical and Volume Control System
DC	Direct Current
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EFIC	Emergency Feedwater Initiation and Control
EFW	Emergency Feedwater
EOP	Emergency Operating Procedure
ERCW	Emergency Raw Cooling Water
FW	Feedwater
HCLPF	High Confidence of Low Probability of Failure
HPCI	High Pressure Coolant Injection
HPCS	High Pressure Core Spray
HPI	High Pressure Injection
HPSI	High Pressure Safety Injection
HR	Heat Removal
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
ICONE	International Conference on Nuclear Engineering
ICW	Intermediate Cooling Water
IPE	Individual Plant Examination
ISLOCA	Interfacing System LOCA

KV	Kilo-Volts
LOCA	Loss of Coolant Accident
LOP	Loss of Power
LOSW	Loss of Service Water
LPCI	Low Pressure Coolant Injection
LPI	Low Pressure Injection
LPSI	Low Pressure Safety Injection
MAB	Maximum Attainable Benefit
MCC	Motor Control Center
MD	Motor Driven
MFW	Main Feed Water
MG	Motor Generator
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
PC	Plant Change
PMP	Probable Maximum Precipitation
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Analysis
PRT	Pressurizer Relief Tank
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RB	Reactor Building
RCIC	Reactor Core Isolation Cooling
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RV	Relief Valve
S/G	Steam Generator
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SAMG	Severe Accident Management Guideline
SBO	Station Blackout
SI	Safety Injection
SGTR	Steam Generator Tube Rupture
SLC	Standby Liquid Control
SRV	Safety Relief Valve
SSE	Safe Shutdown Earthquake
SW	Service Water
TD	Turbine Driven
TDP	Turbine Driven Pump
TVA	Tennessee Valley Authority
V	Volts
WBN	Watts Bar Nuclear Plant