Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7279
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

February 29, 2000

HL-5853

Docket Nos. 50-321
50-366

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

Edwin I. Hatch Nuclear Plant
Application for Renewed Operating Licenses

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR §50, §51 and §54, Southern Nuclear Operating Company (SNC) hereby applies for the renewal of the operating licenses for the Edwin I. Hatch Nuclear Plant, Units 1 and 2.

SNC is the licensed operator of Plant Hatch, which it operates for the benefit of Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia and the City of Dalton (collectively, the "Owners"). The current license for Unit 1 (Facility Operating License No. DPR-57) expires on August 6, 2014, and the license for Unit 2 (Facility Operating License No. NPF-5) expires on June 13, 2018. By this license renewal application, SNC seeks to extend the operating term for each unit by 20 years, so that the Unit 1 license will expire on August 6, 2034, and the Unit 2 license will expire on June 13, 2038.

This application contains the information required by the Commission's license renewal regulations which are set forth in 10 CFR §54.19, §54.21, §54.22 and §54.23. The application provides information to support the 10 CFR §54.29 findings required to issue the renewed licenses sought by this application.

The technical information relating to plant design contained in this application is complete and accurate as of September 10, 1999. Any changes to plant design which occur after this date will be taken into consideration in the annual application updates provided in accordance with §54.21(b).

SNC is the first licensee to submit an application to renew a General Electric designed boiling water reactor plant. For this reason, SNC in a letter to the Commission dated October 27, 1998, requested relief from certain 10 CFR §170 review fees for the Plant Hatch license renewal submittals.

A083

Pursuant to the Southern Nuclear Request for Exception to 10 CFR 50.4(b) and 50.4(c), the signed original and 51 copies of the application in the CD-ROM format are provided, in addition to the copies provided to individuals as designated in the distribution of this letter.

All distribution hr. only except: File Center 01 NRC PDR

PM distributed CD-ROM copies.

Finally, SNC requests that the Commission complete its review of this application and issue the final safety evaluation report for the renewed licenses within 585 days of this filing. To this end, Southern Nuclear will work with the Commission to ensure a thorough and timely review of this application.

Mr. H. L. Sumner, Jr. states he is Vice President of Southern Nuclear Operating Company and is authorized to execute this oath on behalf of Southern Nuclear Operating Company, and to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

Sworn to and subscribed before me this 22nd *day of* February *2000.*

Janice O. Davis
Notary Public

My Commission Expires: ~~MY COMMISSION EXPIRES SEPTEMBER 17, 2000~~

JM/eb

Enclosure: Application for License Renewal for Edwin I. Hatch Nuclear Plant, Units 1 and 2

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager (w/ 1 Application CD)
SNC Document Management (R-Type A02.001) (w/ 1 Application CD)

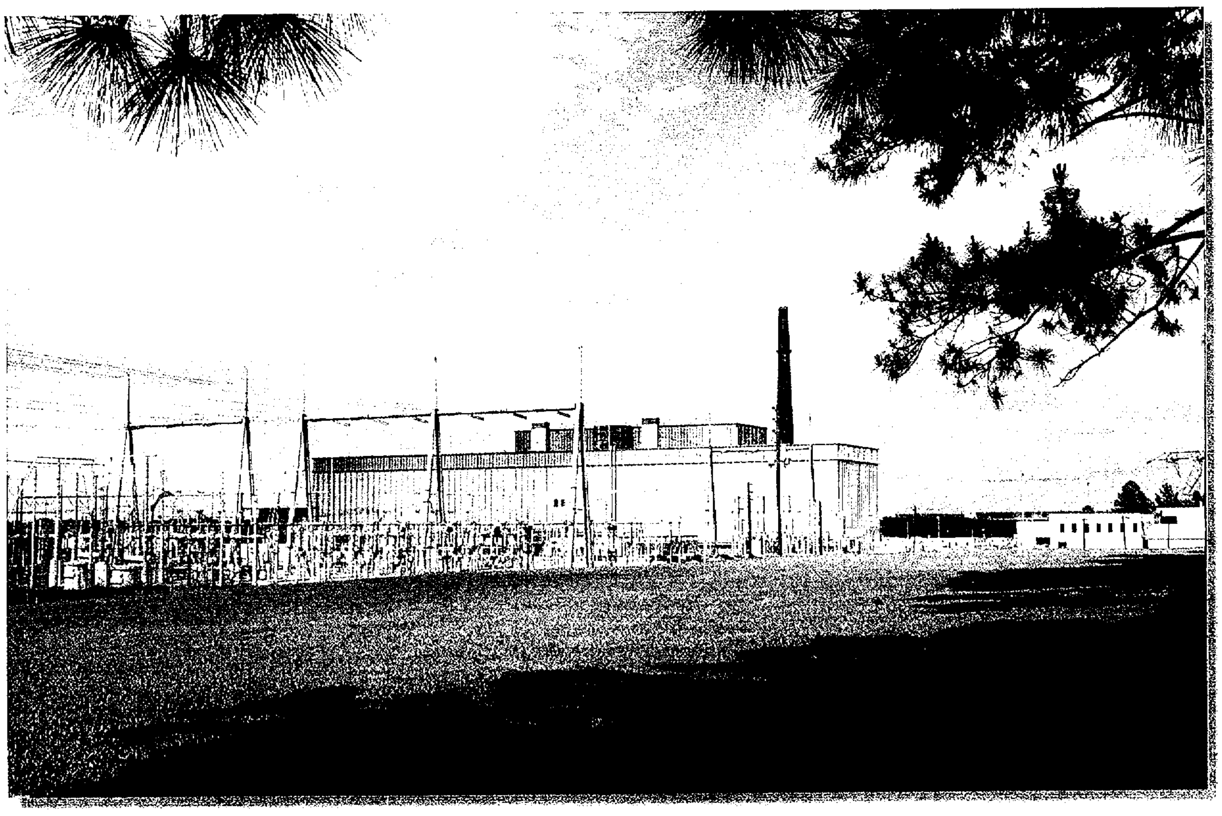
U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. C. I. Grimes, Director, License Renewal Project Directorate (w/ 1 paper copy of Application)
Mr. L. N. Olshan, Project Manager – Hatch (w/ 1 Application CD)
Mr. Samuel J. Collins, Director, Office of Nuclear Reactor Regulation (w/ 41 Application CDs)

U.S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator (w/ 2 Application CDs)
Mr. J. T. Munday, Senior Resident Inspector – Hatch (w/ 1 Application CD)

Appling County, Georgia
Chairman, Appling County Commissioners (w/ 1 Application CD)


Edwin I. Hatch Nuclear Plant
License Renewal Application
SOUTHERN COMPANY
Energy to Serve Your World
All rights reserved
© 2000, Southern Company

Edwin I. Hatch Nuclear Plant
License Renewal Application



Volume 1

SOUTHERN COMPANY
Energy to Serve Your World®

Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7279
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

February 29, 2000

Docket Nos. 50-321
50-366

HL-5853

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

Edwin I. Hatch Nuclear Plant
<u>Application for Renewed Operating Licenses</u>

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR §50, §51 and §54, Southern Nuclear Operating Company (SNC) hereby applies for the renewal of the operating licenses for the Edwin I. Hatch Nuclear Plant, Units 1 and 2.

SNC is the licensed operator of Plant Hatch, which it operates for the benefit of Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia and the City of Dalton (collectively, the "Owners"). The current license for Unit 1 (Facility Operating License No. DPR-57) expires on August 6, 2014, and the license for Unit 2 (Facility Operating License No. NPF-5) expires on June 13, 2018. By this license renewal application, SNC seeks to extend the operating term for each unit by 20 years, so that the Unit 1 license will expire on August 6, 2034, and the Unit 2 license will expire on June 13, 2038.

This application contains the information required by the Commission's license renewal regulations which are set forth in 10 CFR §54.19, §54.21, §54.22 and §54.23. The application provides information to support the 10 CFR §54.29 findings required to issue the renewed licenses sought by this application.

The technical information relating to plant design contained in this application is complete and accurate as of September 10, 1999. Any changes to plant design which occur after this date will be taken into consideration in the annual application updates provided in accordance with §54.21(b).

SNC is the first licensee to submit an application to renew a General Electric designed boiling water reactor plant. For this reason, SNC in a letter to the Commission dated October 27, 1998, requested relief from certain 10 CFR §170 review fees for the Plant Hatch license renewal submittals.

Pursuant to the Southern Nuclear Request for Exception to 10 CFR 50.4(b) and 50.4(c), the signed original and 51 copies of the application in the CD-ROM format are provided, in addition to the copies provided to individuals as designated in the distribution of this letter.

Finally, SNC requests that the Commission complete its review of this application and issue the final safety evaluation report for the renewed licenses within 585 days of this filing. To this end, Southern Nuclear will work with the Commission to ensure a thorough and timely review of this application.

Mr. H. L. Sumner, Jr. states he is Vice President of Southern Nuclear Operating Company and is authorized to execute this oath on behalf of Southern Nuclear Operating Company, and to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

Sworn to and subscribed before me this 22nd *day of* February *2000.*

Janice O. Davis
Notary Public

My Commission Expires: MY COMMISSION EXPIRES SEPTEMBER 17, 2000

JM/eb

Enclosure: Application for License Renewal for Edwin I. Hatch Nuclear Plant, Units 1 and 2

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager (w/ 1 Application CD)
SNC Document Management (R-Type A02.001) (w/ 1 Application CD)

U.S. Nuclear Regulatory Commission, Washington, D.C.
C. I. Grimes, Director, License Renewal Project Directorate (w/ 1 paper copy of Application)
Mr. L. N. Olshan, Project Manager – Hatch (w/ 1 Application CD)
Mr. Samuel J. Collins, Director, Office of Nuclear Reactor Regulation (w/ 41 Application CDs)

U.S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator (w/ 2 Application CDs)
Mr. J. T. Munday, Senior Resident Inspector – Hatch (w/ 1 Application CD)

Appling County, Georgia
Chairman, Appling County Commissioners (w/ 1 Application CD)
County Courthouse
Baxley, Georgia 31513

BEFORE THE
UNITED STATES NUCLEAR REGULATORY COMMISSION

UNIT NO. 1 – Docket No. 50-321

UNIT NO. 2 – Docket No. 50-366

In the Matter of

Southern Nuclear Operating Company, Inc.

APPLICATION FOR LICENSE RENEWAL

UNDER THE ATOMIC ENERGY ACT OF 1954

AS AMENDED

For

EDWIN I. HATCH NUCLEAR PLANT

UNITS 1 AND 2

SOUTHERN NUCLEAR OPERATING COMPANY, INC.
APPLICATION FOR RENEWED OPERATING LICENSES

Table of Contents

SECTION 3 AGING MANAGEMENT REVIEW RESULTS

SECTION 4 TIME-LIMITED AGING ANALYSES

APPENDICES

APPENDIX A FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

APPENDIX C IDENTIFICATION OF AGING EFFECTS AND AGING MANAGEMENT REVIEW SUMMARIES

List of Tables

SECTION 2

List of Figures

Section 1

INTRODUCTION

CONTENTS

1.1 GENERAL INFORMATION – 10 CFR 54.19

1.1.1 NAMES OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company hereby applies for renewed operating licenses for Plant Hatch Units 1 and 2. SNC submits this application individually and as agent for the co-owner licensees named on the operating license. The co-owner licensees are:

- Georgia Power Company
- Oglethorpe Power Corporation
- Municipal Electric Authority of Georgia
- City of Dalton, Georgia

1.1.2 ADDRESSES OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company, Inc.
40 Inverness Center Parkway
P.O. Box 1295
Birmingham, Alabama 35201-1295

Georgia Power Company
241 Ralph McGill Boulevard
Atlanta, Georgia 30308

Oglethorpe Power Corporation
2100 East Exchange Place
P.O. Box 1349
Tucker, GA 30085-1349

Municipal Electric Authority of Georgia
1470 Riveredge Parkway
Atlanta, Georgia 30328

The City of Dalton
1200 V. D. Parrott, Jr. Parkway
Dalton, Georgia 30720

1.1.3 DESCRIPTIONS OF BUSINESS OR OCCUPATION OF APPLICANT AND CO-OWNERS

Southern Nuclear Operating Company, Inc.

SNC is engaged in the operation of nuclear power plants. SNC operates the Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2 and the Vogtle Electric Generating Plant (VEGP), Units 1 and 2 for Georgia Power Company (GPC), Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia (the co-owners); and the Joseph M. Farley Nuclear Plant (FNP) for Alabama Power Company. The combined electric generation of the three plants is in excess of 5,900 MW.

SNC is the exclusive licensed operator of the co-owners' nuclear facility, HNP, which is the subject of this application. The current Unit 1 license (Facility Operating License No. DPR-57) expires on August 6, 2014, and the current Unit 2 license (Facility Operating License No. NPF-5) expires on June 13, 2018. SNC will be named as the exclusive licensed operator on the renewed operating licenses.

Georgia Power Company

Georgia Power Company (GPC) is engaged in the generation and transmission of electricity and the distribution and sale of such electricity within the State of Georgia. Georgia Power Company serves more than 1.7 million customers in a service area of approximately 57,000 square miles constituting 97 percent of the State of Georgia's land area. With a rated capability of approximately 14,000 MW, GPC currently provides retail electric service in all but 6 of Georgia's 159 counties. GPC is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

Oglethorpe Power Corporation

Oglethorpe Power Corporation (an Electric Membership Corporation) supplies electricity at wholesale to 39 Electric Membership Corporations in the State of Georgia, which in turn distribute this electricity at retail to their residential, commercial and industrial customers. Oglethorpe is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

Municipal Electric Authority of Georgia

MEAG is an electric generation and transmission public corporation, which provides wholesale power to 48 communities in the State of Georgia and other wholesale customers. These communities, in turn, supply electricity to more than 675,000 retail consumers, in their respective service areas across the state, representing approximately 10 percent of Georgia's population. MEAG is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed license.

City of Dalton

The City of Dalton is a municipality within the State of Georgia. Acting by and through Dalton Utilities, its Board of Water, Light and Sinking Fund Commissioners, Dalton owns electric generation capacity, transmission capacity and a distribution system. Dalton is a duly incorporated municipality under the laws of the State of Georgia. Dalton is a co-owner and licensee of HNP and will be named as a co-owner licensee on the renewed licenses.

1.1.4 DESCRIPTIONS OF ORGANIZATION AND MANAGEMENT OF APPLICANT AND CO-OWNERS

SOUTHERN NUCLEAR OPERATING COMPANY, INC.

SNC is a Delaware corporation with its principal office in Birmingham, Alabama. It is a wholly-owned subsidiary of Southern Company, a company registered under the Public Utility Holding Company Act of 1935, having its principal place of business in Atlanta, Georgia. Other subsidiaries of Southern Company include Georgia Power Company, Alabama Power

Company, Gulf Power Company, Mississippi Power Company, Savannah Electric, Southern Company Services, Inc., Southern Linc, and Southern Energy.

Neither SNC nor its parent, Southern Company, is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. SNC files this application on its own behalf and as agent of the co-owners.

The names and business addresses of SNC's directors and principal officers, all of whom are citizens of the United States, are as follows:

Directors

A. W. Dahlberg, III Chairman & Chief Executive Officer Southern Company	270 Peachtree Street Atlanta, Georgia 30303
H. A. Franklin President and Chief Operating Officer Southern Company	270 Peachtree Street Atlanta, Georgia 30303
D. M. Ratcliffe President & Chief Executive Officer Georgia Power Company	241 Ralph McGill Boulevard Atlanta, Georgia 30308
E. B. Harris President and Chief Executive Officer Alabama Power Company	600 North 18th Street Birmingham, Alabama 35202
W. G. Hairston, III President & Chief Executive Officer Southern Nuclear Operating Company, Inc.	P.O. Box 1295 Birmingham, Alabama 35201

Principal Officers

W. G. Hairston III, President and CEO, Birmingham, Alabama
J. D. Woodard, Executive Vice President, Birmingham, Alabama
D. N. Morey III, Farley Vice President, Birmingham, Alabama
H. L. Sumner, Jr., Hatch Vice President, Birmingham, Alabama
J. B. Beasley, Jr., Vogtle Vice President, Birmingham, Alabama
L. B. Long, Technical Services Vice President, Birmingham, Alabama
J. W. Averett, Administrative Services Vice President, Birmingham, Alabama
J. O. Meier, Vice President and Corporate Counsel, Birmingham, Alabama
S. A. Mitchell, Corporate Secretary, Birmingham, Alabama
K. S. King, Comptroller and Treasurer, Birmingham, Alabama
D. J. Burnett, Assistant Corporate Secretary, Birmingham, Alabama

GEORGIA POWER COMPANY

GPC is a Georgia corporation with its principal office in Atlanta, Georgia. GPC is a wholly-owned subsidiary of Southern Company, a Delaware corporation with its principal office in Atlanta, Georgia.

The names and business addresses of Georgia Power Company's directors and principal officers, all of whom are citizens of the United States, are as follows:

Directors

Daniel P. Amos	1931 Wynnton Road Columbus, Georgia 31999
Juanita P. Baranco	7060 Jonesboro Road Morrow, Georgia 30260
William A. Fickling, Jr.	577 Mulberry Street, Suite 1100 Macon, Georgia 31202-1976
H. Allen Franklin	270 Peachtree Street, Suite 2200 Atlanta, Georgia 30303
L. G. Hardman, III	1731 North Elm Street Commerce, Georgia 30529
Warren Y. Jobe	270 Peachtree Street Atlanta, Georgia 30303
James R. Leintz, Jr.	600 Peachtree Street NE Atlanta, Georgia 30302-4899
Zell Miller	3455 Peachtree Road NE, Suite 750 Atlanta, Georgia 30326

G. Joseph Prendergrast	191 Peachtree Street, NE 31st floor Atlanta, Georgia 30308
David M. Ratcliffe	241 Ralph McGill Blvd., NE Atlanta, Georgia 30308
Herman J. Russell	504 Fair Street, SW Atlanta, Georgia 30313
William Jerry Vereen	301 Riverside Drive Moultrie, Georgia 31776-0460
Carl Ware	1 Coca Cola Plaza Atlanta, Georgia 30313

Principal Officers

David M. Ratcliffe, President and CEO, Atlanta, Georgia
T. A. Fanning, Executive V.P., Treasurer and CFO, Atlanta, Georgia
W. C. Archer, III, Executive V.P., External Affairs, Atlanta, Georgia
G. R. Hodges, Executive V.P., Customer Operations, Atlanta, Georgia
W. Y. Jobe, Executive V.P., Georgia Power Company, Atlanta, Georgia
L. J. Haynes, Sr. V.P., Marketing, Atlanta, Georgia
W. T. Dalke, Sr. V.P., Power Delivery, Atlanta, Georgia
J. K. Davis, Sr. V.P., Corporate Relations, Atlanta, Georgia
R. H. Haubein, Jr., Sr. V.P., GPC-Southern Company, Generation, Atlanta, Georgia
F. D. Williams, Sr. V.P., Resource Planning and Policy, Atlanta, Georgia

Neither GPC nor its corporate parent, Southern Company, is owned, controlled, or dominated by an alien, foreign corporation, or foreign government.

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

MEAG is public corporation and an instrumentality of the State of Georgia, a body corporate and politic, created by the General Assembly of the State of Georgia in its 1975 Session (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 3).

The names and addresses of MEAG's principal officers and the members of its governing body, all of whom are citizens of the United States, are as follows:

Authority Members (Governing board)

John H. Flythe, Chairman of the Board	P. O. Box 631 Adel, Georgia 31620
Kelly Cornwell, Vice Chairman	P. O. Box 248 Calhoun, Georgia 30703-0248
Steve Rentfrow Secretary Treasurer	P. O. Box 1218 Cordele, Georgia 31010

Patrick Bowie, Board Member	P. O. Box 430 LaGrange, Georgia 30241
The Honorable Ansley L. Meaders, Board Member	205 Lawrence Street Marietta, Georgia 30061
Roland C. Stubbs Jr., Board Member	113 Sylvan Terrace Sylvania, Georgia 30467
The Honorable Gerald Thompson Board Member	P. O. Box 425 Fitzgerald, Georgia 31750
Kerry Waldron, Board Member	P. O. Box 672 Thomaston, Georgia 30286-0009
Joel T. Wood Board Member	P. O. Box 487 West Point, Georgia 31833

Principal Officers

Robert P. Johnston, President	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328
Mary Jackson, Vice President and Chief Financial Officer	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328
James Fuller, Treasurer	14370 Riveredge Pkwy. NW Atlanta, Georgia 30328

MEAG is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

OGLETHORPE POWER CORPORATION

Oglethorpe Power Corporation (an Electric Membership Corporation) operating on a not-for-profit basis, was organized under the Georgia Electric Membership Corporation Act (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 4) and other applicable laws of the State of Georgia.

The names and addresses of Oglethorpe's principal officers and the members of its governing body, all of whom are citizens of the United States, are as follows:

Board of Directors

J. Calvin Earwood, Chairman	2100 East Exchange Place Tucker, GA 30085-1349
Benny W. Denham, Vice Chairman	2100 East Exchange Place Tucker, GA 30085-1349

Mac F. Oglesby, Treasurer	2100 East Exchange Place Tucker, GA 30085-1349
Larry N. Chadwick, NW Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Sammy Jenkins, SE Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Sam Rabun, Central Regional Director	2100 East Exchange Place Tucker, GA 30085-1349
Ashley C. Brown, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
Newton A. Campbell, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
Wm. Ronald Duffy, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349
John S. Ranson, Outside Director	2100 East Exchange Place Tucker, GA 30085-1349

Principal Officers

Thomas A. Smith, President and Chief Executive Officer	2100 East Exchange Place Tucker, GA 30085-1349
Michael W. Price, Chief Operating Officer	2100 East Exchange Place Tucker, GA 30085-1349
W. Clayton Robbins, Senior Vice President, Finance and Administration	2100 East Exchange Place Tucker, GA 30085-1349
Clarence D. Mitchell, Senior Vice President, Operations and Projects	2100 East Exchange Place Tucker, GA 30085-1349
Betsy Higgins, Vice President, Assistant to the CEO	2100 East Exchange Place Tucker, GA 30085-1349
Dale R. Murphy, Vice President, Planning and Administration	2100 East Exchange Place Tucker, GA 30085-1349
Robert D. Steele, Vice President, External Affairs	2100 East Exchange Place Tucker, GA 30085-1349

Glenn Loomer Vice President, Contracts and Analysis	2100 East Exchange Place Tucker, GA 30085-1349
Willie Collins, Controller and Chief Risk Officer	2100 East Exchange Place Tucker, GA 30085-1349
James E. Kofron, Corporate Treasurer	2100 East Exchange Place Tucker, GA 30085-1349
Patricia N. Nash, Corporate Secretary	2100 East Exchange Place Tucker, GA 30085-1349

Oglethorpe is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

CITY OF DALTON

The names and addresses of Dalton's governing body (councilmen) and principal officers (mayor and city administrator), all of whom are citizens of the United States, are as follows:

Councilmen

Ray Elrod, Mayor	1508 Rio Vista Drive Dalton, GA 30720
Bobby Joe Grant	Paramount Printing P. O. Box 4569 Dalton, GA 30719-4569
Charles Whitener	123 Lisa Lane Dalton, GA 30720
Terry Christie	607 Murray Hill Drive Dalton, GA 30720
Michael Robinson	2006 West Brookhaven Circle Dalton, GA 30720

Officers

Ray Elrod, Mayor	1508 Rio Vista Drive Dalton, GA 30720

Butch Sanders, City Administrator	City Hall P. O. Box 1205 Dalton, GA 30722-1205
Faye Martin, City Clerk	City Hall P. O. Box 1205 Dalton, GA 30722-1205

Dalton is neither owned, controlled, nor dominated by an alien, foreign corporation, or foreign government.

The names and addresses of Dalton Utilities' governing body (Commissioners) and principal officers (chairman, president/chief executive officer, and secretary), all of whom are citizens of the United States, are as follows:

Commissioners

Justin Robinson Chairman	2203 Druid Lane Dalton, GA 30720
Norman D. Burkett Vice Chairman	2209 Rocky Face Circle Dalton, GA 30720
Todd Reigel Secretary	c/o Paradigm Printing, Inc. 429 Virgil Drive Dalton, GA 30720
George Mitchell	c/o Dalton Paving & Construction Company 530 North Elm Street Dalton, GA 30720
Jim Bethel	c/o J & J Industries, Inc. 818 J & J Drive Dalton, GA 30720

Officers

Justin Robinson Chairman	2203 Druid Lane Dalton, GA 30720
Don Cope President/Chief Executive Officer	1200 V. D. Parrott, Jr. Parkway Dalton, GA 30720

Todd Reigel Secretary	c/o Paradigm Printing, Inc. 429 Virgil Drive Dalton, GA 30720

1.1.5 CLASS OF LICENSE, USE OF THE FACILITY, AND PERIOD OF TIME FOR WHICH THE LICENSE IS SOUGHT

SNC requests a Class 104 operating license for Plant Hatch Unit 1 and a Class 103 operating license for Unit 2 (License Nos. DPR-57 and NPF-5, respectively) for a period 20 years beyond the expiration of the current licenses, midnight, August 6, 2014 for Unit 1 and midnight, June 13, 2018 for Unit 2.

Because the current licensing basis is carried forward with the possible exception of some aging issues, Southern Nuclear expects the form and content of the licenses to be generally the same as they now exist. Southern Nuclear, thus, also requires similar extensions of specific licenses under Parts 30, 40, and 70 that are contained in the current operating licenses.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

No physical plant alterations or modifications have been identified as necessary in order to implement the provisions of this application.

1.1.7 RESTRICTED DATA

With regard to the requirements of 10 CFR 54.17(f), this application does not contain any "Restricted Data," as that term is defined in the Atomic Energy Act of 1954, as amended, or other defense information, and it is not expected that any such information will become involved in these licensed activities.

In accordance with the requirements of 10 CFR 54.17(g), the applicants 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 10 CFR Parts 25 and/or 95.

1.1.8 REGULATORY AGENCIES

The direct costs incurred by SNC in connection with HNP are billed directly to GPC. Expenses which are not direct charges to specific plants are allocated to GPC and others for whom the expenses are incurred, as appropriate. GPC recovers a portion of HNP direct and allocated costs from the other co-owners in relation to their respective ownership interests in HNP, and the remainder through rates. The rates charged and services provided by GPC are subject to the jurisdiction of the Georgia Public Service Commission and the Federal Energy Regulatory Commission.

Georgia Public Service Commission
244 Washington St. S.W.
Atlanta, Georgia 30334

Federal Energy Regulatory Commission
888 First St. N.E.
Washington, DC 20426

1.1.9 LOCAL NEWS PUBLICATIONS

News publications in circulation near Plant Hatch which are considered appropriate to give reasonable notice of the application are as follows:

The Baxley News-Banner
P.O. Box 409
Baxley, Georgia 31513
912-367-2468
Fax-912-367-0277

Vidalia Advance-Progress
P.O. Box 669
Vidalia, GA 30474
912-537-4899
Fax-912-537-4899

The Tattnall Journal
P.O. Box 278
Reidsville, GA 30453
912-557-6761
Fax-912-557-4132

The Jeff Davis Ledger
P.O. Box 338
Hazlehurst, GA 31539
912-375-4225
Fax-912-375-3704

The Macon Telegraph
P.O. Box 4167
Macon, GA 31208
912-744-4200
Fax-912-744-4385

Savannah Morning News
P.O. Box 1088
Savannah, GA 31402
912-236-9511
Fax-912-234-6522

1.1.10 CONFORMING CHANGES TO STANDARD INDEMNITY AGREEMENT

10 CFR 54.19(b) requires that "each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." Article VII of the original Indemnity Agreement, which was issued on August 2, 1973, along with the HNP Materials License, provides that the Agreement will terminate at the expiration of the license identified in Item 3 of the Attachment

(SNM-1378). Since August 2, 1973, the Indemnity Agreement has been amended from time to time. Two of these amendments added license numbers DPR-57 and NPF-5 to Item 3 of the Attachment. As a consequence of these amendments, the existing Indemnity Agreement is presently due to terminate at midnight, June 13, 2018, as the last of these two licenses expires. SNC requests that conforming changes be made to Item 3 of the Attachment to the Indemnity Agreement (and any other provision of the Attachment or Indemnity Agreement) to make clear that the Indemnity Agreement is extended until the expiration date of the renewed HNP operating licenses issued by the Commission in response to this application.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSES, AND RENEWAL TERM OPERATION

In accordance with 10 CFR 54.21(b), during NRC review of this application, SNC will provide an annual update to the application to reflect any information updates and agreements made with the NRC. SNC plans to work with the NRC to establish an application update procedure that is most beneficial toward supporting NRC's review process, rather than associating this requirement with a specific date based on the application submittal date.

In accordance with 10 CFR 54.37(b), SNC will maintain a summary list of programs in the FSAR which are required to manage the effects of aging and the evaluation of time-limited aging analyses for the systems, structures or components in the scope of license renewal during the period of extended operation.

1.2.2 INCORPORATION BY REFERENCE

The only documents to be incorporated by reference as part of this application are those documents specifically identified in sections titled "Documents Incorporated by Reference." Any document references, either in text or in sections titled "General References" are listed for information only.

1.2.3 CONTACT INFORMATION

Any notices, questions, or correspondence in connection with this filing should be directed to:

Mr. H. L. Sumner
Vice President - Hatch Project
Southern Nuclear Operating Company
40 Inverness Center Parkway
P.O. Box 1295
Birmingham, AL 35201-1295

with copies to:

Mr. Stan Blanton
Balch and Bingham
P.O. Box 306
Birmingham, AL 35201

Mr. C. R. Pierce
Southern Nuclear Operating Company
40 Inverness Center Parkway
P. O. Box 1295
Birmingham, AL 35201-1295

1.3 PURPOSE

This document is intended to provide information required by 10 CFR to support the application for a renewed license for the Edwin I. Hatch Nuclear Plant. The application contains technical information required by 10 CFR 54.21, technical specification changes required by 10 CFR 54.22, and environmental information required by 10 CFR 54.23. The information contained herein is intended to provide the NRC with an adequate basis to make the finding required by 10 CFR 54.29.

1.4 DESCRIPTION OF EDWIN I. HATCH NUCLEAR PLANT

Plant Edwin I. Hatch is a two-unit boiling water reactor (BWR) located on the south side of the Altamaha River in Appling County, Georgia, approximately 11 miles north of Baxley, Georgia. The reactor buildings and turbine buildings are separate for each unit. The control building is a shared facility between the two turbine buildings. The turbine buildings and control building are connected in such a manner as to provide a common turbine hall. Similarly, the refueling floors of both reactor buildings are joined together into a single area. The nuclear steam supply systems (NSSS) for both units include BWR 4, 1967 product line, 218-in. vessels, designed and supplied by GE. The containments are of the Mark I design, incorporating a drywell and torus to provide pressure suppression. The design operating power level for both units is 2763 MWt.

1.5 APPLICATION STRUCTURE

The application is divided into the following major sections:

***Section 1** – Introduction and Administrative Information*

This section describes the plant and states the purpose for this application. Included in this section are the names, addresses, business descriptions, and organization and management descriptions of the applicant and the co-owners of Plant Hatch, as well as other administrative information.

***Section 2** – Structures and Components Subject To An Aging Management Review*

A scoping and screening methodology is presented in this section. This section satisfies the requirements of 10 CFR 54.21(a)(2) to describe and justify the methods used to identify those structures and components subject to an aging management review (AMR).

Also included in this section are the scoping and screening results. The scoping results are presented in Table 2.2-1. This table lists plant system functions and denotes which functions are within license renewal scope.

Screening results are presented in sections 2.3 through 2.5. The screening results consist of lists of component types that require an aging management review, arranged by system. Also included with the screening results, as background information, are brief descriptions of in-scope system functions (intended functions) and associated systems.

Key intended function evaluation boundary drawings for most mechanical intended functions are provided as information under separate cover and do not constitute a part of this application.

***Section 3** – Aging Management Review Results*

AMR results are presented in tabular form, arranged by the system or structure principally associated with one or more intended functions. These tables identify the aging effects and the programs credited with managing the aging effects for component groups within the scope of license renewal.

***Section 4** – Time Limited Aging Analyses*

Time limited aging analyses (TLAAs) are discussed in this section, with a disposition method specified for each.

***Appendix A** – Final Safety Analysis Report Supplement*

As required by 10 CFR 54.21(d), the Final Safety Analysis Report (FSAR) supplement contains a summary of programs and activities credited for aging management during the renewal term. Also contained in Appendix A is a list of the TLAAs and their dispositions.

Appendix B – Aging Management Programs and Activities

Program summaries are provided in Appendix A – FSAR Supplement.

Appendix C – Commodity Group Aging Management Review Results

Each structure or component subject to aging management review was evaluated in one or more AMRs. The AMR results are summarized in section C.2. A discussion of aging effect determinations is provided in section C.1.

Appendix D – Environmental Report Supplement

This appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report that complies with the requirements of subpart A of 10 CFR Part 51.

Appendix E – ***Required Technical Specification Changes***

This appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the period of extended operation.

One Technical Specification change will be required in order to revise the vessel pressure-temperature curves to account for the effects or irradiation of the core beltline over the extended operating period.

1.6 DEFINITIONS

SNC terminology used in this document is defined below. In addition, definitions for the terms CLB, IPA, and TLAA are provided in 10 CFR 54.3.

Active: As used in relation to a structure, component, or commodity group, the performance of a function with either moving parts or a change in configuration or properties. Examples of active components include pumps (except casings), motors, valves (except bodies), etc. Additional examples may be found in 10 CFR 54.21.

Aging Effect: A change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms that degrade the ability of a system, structure, or component to perform its function. Examples include loss of material, cracking, and material property changes.

Aging Mechanisms: The physical or chemical processes that result in degradation. These mechanisms include, but are not limited to fatigue, erosion, corrosion, thermal and radiation embrittlement, microbiologically influenced corrosion, creep, and shrinkage. Aging mechanisms produce aging effects.

Commodity Group (CG) (also Commodity): A grouping of a select number of structures, components, or commodities, based upon considerations such as physical configuration, intended use, materials of construction, environment, management programs, or common aging effects. Commodity groups may be addressed by a single aging management review, when applicable, to achieve efficiency in the aging management review process.

Component: The major structural, mechanical, and/or electrical elements of a system or structure.

Component Function: The specific function of the structure or component that supports an intended function.

Component Group: A grouping of like components. Similarity of components is determined based on component type, component function, materials of construction, and internal and external environments, as applicable. Component groups are uniquely defined for each intended function evaluation boundary. Each component group only contains one component type.

Component Type: A descriptive label used to distinguish different components from each other. The label is usually the same as the common name for the component. For example, "valve" is a component type. Thus, all valves, regardless of brand or other distinguishing features, belong to the "valve" component type.

Consumables: Piece parts of components that are replaced as a normal part of ongoing maintenance activities. Examples include packing, gaskets, sealing material, and O-rings.

Equipment Location Index (ELI): A Plant Hatch controlled and periodically updated list of major plant equipment that gives the equipment master parts list (MPL) number, a brief description, location by column line and elevation, major drawings associated with the equipment, quality classification codes, vendor specifications, and purchase order numbers.

Environmental Qualification Master List: The Plant Hatch list of all equipment included in the 10 CFR 50.49 Environmental Qualification Program. The list includes equipment with individual MPL numbers, as well as commodity items such as cables, splices, and seals.

Evaluation Boundary: The portion of a system or structure, and its related components, that is necessary to accomplish an intended function. The intent in defining an evaluation boundary is to quickly focus the aging management review on the set of structures and components that directly contribute to the successful completion of the system's or structure's intended function. This boundary may or may not match the system or structure boundary traditionally described in plant documents.

Intended Function: The function(s) that is the basis for including the system, structure, or component within the scope of the Rule as specified in 10 CFR 54.4(a). This definition is unique and only applies to implementing the requirements of the Rule.

In-Scope: A term applied to structures, systems, components, or commodities determined to be subject to the requirements of 10 CFR 54.

Long-lived: An item that is not subject to replacement based on a qualified life or specified time period.

Maintenance Rule Scoping Manual: The Plant Hatch document that identifies systems and system functions included in the scope of the Maintenance Rule, 10 CFR 50.65.

Operating Term: 40 years, or as otherwise specified in the plant's operating license.

Passive: As used in relation to a structure, component, or commodity group, the performance of a function without moving parts or without a change in configuration or properties. Examples include the reactor vessel, the reactor coolant pressure boundary, etc.

Short-lived: An item that is either subject to replacement based upon a qualified life or specified time period.

Spaces: A term used in the electrical component and commodity evaluation process that describes a plant room or boundary for an electrical aging management review. "Spaces" also refers to the evaluation approach described more fully in Sandia National Laboratory Report SAND 96-0344.

Structure: A building or structural assembly that supports and/or encloses systems and/or components.

System: Any collection of equipment that is configured and operated to serve one or more functions (e.g., provide water to the torus, spray water into the containment, inject water into the primary pressure boundary).

System Evaluation Document (SED): A Plant Hatch controlled document issued for the purpose of defining safety-related equipment. It is composed of a written description of safety-related systems, including identification of primary system operating modes, and the Safety-Related Components List (SCL).

ACRONYMS

ACRONYM	DEFINITION
ADS	Automatic Depressurization System
AMR	Aging Management Review
ASME	American Society of Mechanical Engineers
ATTS	Analog Transmitter Trip System
ATWS	Anticipated Transient Without Scram
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Program
CAV	Crack Arrest Verification
CCW	Closed Cooling Water
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CRD	Control Rod Drive
CS	Core Spray
CST	Condensate Storage Tank
DBA	Design Basis Accident
DBE	Design Basis Event
DOE	U.S. Department of Energy
ECCS	Emergency Core Cooling System
ECP	Electrochemical Corrosion Potential
EDG	Emergency Diesel Generator
EFPY	Effective Full Power Year
EHC	Electro-Hydraulic Control
ELI	Equipment Location Index
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQRE	Environmental Qualification Report Evaluation
ESF	Engineered Safety Features
FAC	Flow Accelerated Corrosion
FHA	Fire Hazards Analysis
FSAR	Updated Final Safety Analysis Report
GPC	Georgia Power Company
HCU	Hydraulic Control Unit

ACRONYM	DEFINITION
HELB	High Energy Line Break
HNP	Hatch Nuclear Plant
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation, and Air-Conditioning
HWC	Hydrogen Water Chemistry
IASCC	Irradiation Assisted Stress Corrosion Cracking
IGA	Intergranular Attack
IGSCC	Intergranular Stress Corrosion Cracking
IPA	Integrated Plant Assessment
ISI	Inservice Inspection
IST	Inservice Testing
LLS	Low Low Set
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MCREC	Main Control Room Environmental Control
MEAG	Municipal Electric Authority of Georgia
MIC	Microbiologically Influenced Corrosion
MOV	Motor-Operated Valve
MPL	Master Parts List
MSIV	Main Steam Isolation Valve
NEI	Nuclear Energy Institute
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
P&ID	Piping and Instrumentation Diagram
PSW	Plant Service Water
QA	Quality Assurance
QA/CAP	Quality Assurance/Corrective Actions Program
QDP	Qualification Data Package
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RHR	Residual Heat Removal

ACRONYM	DEFINITION
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RTD	Resistance Temperature Detector
RWCU	Reactor Water Cleanup
SBO	Station Blackout
SCC	Stress Corrosion Cracking
SED	System Evaluation Document
SER	Safety Evaluation Report
SGTS	Standby Gas Treatment System
SMP	Structural Monitoring Program
SNC	Southern Nuclear Operating Company
SOC	Statement of Considerations
SRP-LR	Standard Review Plan - License Renewal
SRV	Safety Relief Valve
TLAA	Time-Limited Aging Analyses

1.7 GENERAL REFERENCES

1. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," 56 FR 64976, December 13, 1991.
2. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," 60 FR 22491, May 8, 1995.
3. "NEI 95-10, Revision 0, Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," March 1996.
4. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," 56 FR 31324, July 10, 1991.
5. 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."
6. "License Renewal Demonstration Program: NRC Observations and Lessons Learned," NUREG 1568, December 1996.
7. NEI/NRC License Renewal Work Shop, Reference Documents, October 29, 1997.
8. "License Renewal Demonstration Program Site Visit, Hatch Nuclear Power Plant Trip Report," July 9, 1996.
9. "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," Draft Regulatory Guide DG 1047.
10. 10 CFR 50.48, "Fire Protection."
11. 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," 48 FR 2733, January 21, 1983, as amended by 49 FR 45576, November 19, 1984; 51 FR 40308, November 6, 1986; 51 FR 43709, December 3, 1986; 52 FR 31611, August 21, 1987; 53 FR 19250, May 27, 1988; 61 FR 39300, July 29, 1996; 61 FR 65173, December 11, 1996; 62 FR 47271, September 8, 1997.
12. 10 CFR 50.62, "Requirements for Reduction of Risk From Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants," 49 FR 26044, June 26, 1984; 49 FR 27736, July 6, 1984, as amended by 51 FR 40310, November 6, 1986; and 54 FR 13362, April 3, 1989.
13. 10 CFR 50.63, "Loss of All Alternating Current Power," 53 FR 23215, June 21, 1988.
14. 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," 56 FR 22304, May 15, 1991.
15. "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," Regulatory Guide 1.154.
16. "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," Working Draft, September 1997.
17. "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Terminations," SAND 96-0344, United States Department of Energy.

Section 2

STRUCTURES AND COMPONENTS REQUIRING AGING MANAGEMENT REVIEW

CONTENTS

LIST OF TABLES

LIST OF FIGURES

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 INTRODUCTION

This section describes the process that Southern Nuclear (SNC) used to implement the scoping requirements of Title 10 Code of Federal Regulations (CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, the License Renewal Rule" (Ref. 1) (the "Rule"), as specified in 10 CFR 54.21(a)(2). The specific method SNC used to identify inscope functions and to screen the systems, structures, and components required to perform the inscope functions was developed considering the requirements of the Rule, the Statements of Considerations for the Rule, and the guidance provided by the Nuclear Energy Institute's (NEI) document, NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," (Ref. 2). In addition, SNC also considered Nuclear Regulatory Commission (NRC) staff correspondence with other applicants and with the Nuclear Energy Institute in the development of this methodology.

The methodology was also developed with the knowledge that some provisions of the Rule may be satisfied by the plant's action to comply with the Maintenance Rule, 10 CFR 50.65 (Ref. 3). Unless otherwise clarified or modified in the Statements of Considerations accompanying the 1995 amendments to Part 54 (Ref. 4), the Statements of Considerations for the original (1991) Part 54 (Ref. 5) rulemaking remains valid. Therefore, both Statements of Considerations were considered in developing the Plant Hatch scoping and screening process.

The major processes (and applicable Rule sections in square brackets) described in this methodology are as follow:

- Identification of the systems and structures within the scope of the Rule [10 CFR 54.4].
- Identification of the functions of systems and structures determined to be within the scope of the Rule [10 CFR 54.4 and 10 CFR 54.21]. These functions are the intended functions described in 10 CFR 54.4(b).
- Identification of the structures, components, and commodities (SCCs) subject to aging management review [10 CFR 54.21(a)(1)].

The license renewal documents produced using this methodology are subject to the requirements of Part 50, Appendix B (Ref. 6). License Renewal Services internal procedures provide for the control of documents and records, consistent with quality assurance requirements, during the performance of activities described in this methodology. The technical data and results will be maintained in an auditable format and stored in an approved record storage facility.

As used in the Plant Hatch application methodology, scoping is the process of identifying systems and structures that meet the scoping criteria of 10 CFR 54.4(a)(1) - (3), including the identification of intended functions as defined by 10 CFR 54.4(b)— those functions that are related to meeting one or more of the scoping criteria of 10 CFR 54.4(a)(1) - (3). The scoping criteria, with applicable cross references to sections in this document in square brackets, as applied to plant systems, structures, and components, stated briefly, are:

1. Reactor coolant pressure boundary integrity (10 CFR 54.4(a)(1)(i)) [Section *2.1.2.4*].
2. Safe reactor shutdown and maintenance (10 CFR 54.4(a)(1)(ii)) [Section 2.1.2.4].

3. Accident consequences prevention or mitigation (10 CFR 54.4(a)(1)(iii)) [Section *2.1.2.4*].
4. Nonsafety related whose failure could prevent satisfactory accomplishment of any of the functions associated with items 1-3 (10 CFR 54.4(a)(2)) [Section *2.1.2.5*].
5. Compliance with fire protection regulations (10 CFR 50.48) (10 CFR 54.4(a)(3)) [Section *2.1.2.6*].
6. Compliance with environmental qualification regulations for electrical equipment (10 CFR 50.49) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].
7. Compliance with anticipated transients without scram regulations (10 CFR 50.62) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].
8. Compliance with station blackout regulations (10 CFR 50.63) (10 CFR 54.4(a)(3)) [Section 2.1.2.6].

An additional regulation, 10 CFR 50.61, "Fracture toughness requirements for protection against pressurized thermal shock events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154 (Ref. 7) for boiling water reactor plants is not required.

The identification and listing of structures and components subject to an aging management review is called screening in the Plant Hatch application methodology, and is discussed in Section *2.1.3* for civil/mechanical disciplines, and in Section *2.1.4* for the electrical discipline.

Preparation of drawings depicting the set of inscope structures and components is not a rule requirement. However, evaluation boundary drawings for certain intended functions were developed for use during the screening process. Creation and use of these intended function evaluation boundaries is a part of the screening process employed by SNC. However, these drawings are not a part of this application. The intended function evaluation boundary drawings were used as an aid to facilitate identifying the portions of the systems and structures within the scope of the Rule. See Section 2.1.3.1 for the discussion of intended function evaluation boundaries for civil/mechanical disciplines, and Section 2.1.4 for electrical component screening. Because a plant "spaces" approach was used for electrical components, electrical function boundary drawings were produced only in a few instances to support determination of a specific set of components to be brought in scope.

2.1.2 SCOPING

2.1.2.1 Plant Hatch Systems, Structures, and Intended Functions

10 CFR 54.4 defines the requirements for identifying the systems and structures and their intended functions within the scope of the Rule. As provided in 10 CFR 54.4(a)(1), design basis events for license renewal are applied as defined in 10 CFR 50.49(b)(1), consistent with the Hatch CLB. Section 54.4(b) provides that "the intended functions that these systems, structures, and components must be shown to fulfill in 10 CFR 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1)-(3)" of 10 CFR 54.4(b).

The SNC process for implementing the requirements of 10 CFR 54.4(a) and (b) is summarized by the following steps and described in detail in this Section (2.1.2):

- Plant systems and structures, and their functions were identified.

- Each system and structure function was reviewed to determine whether it met any of the scoping criteria specified in 10 CFR 54.4(a).

If the system or structure function met one or more of the scoping criteria in 10 CFR 54.4(a), then it is within the scope of the Rule and was designated as an intended function as identified in 10 CFR 54.4(b). In most cases, the intended functions of a system or structure are only a subset of all its functions. Most systems and structures also perform other functions that do not meet any of the criteria in 10 CFR 54.4(a). Only the portions of the systems or structures required to support the intended functions are within the scope of the Rule.

Figure 2.1.2-1 presents a simple flow diagram to depict this process.

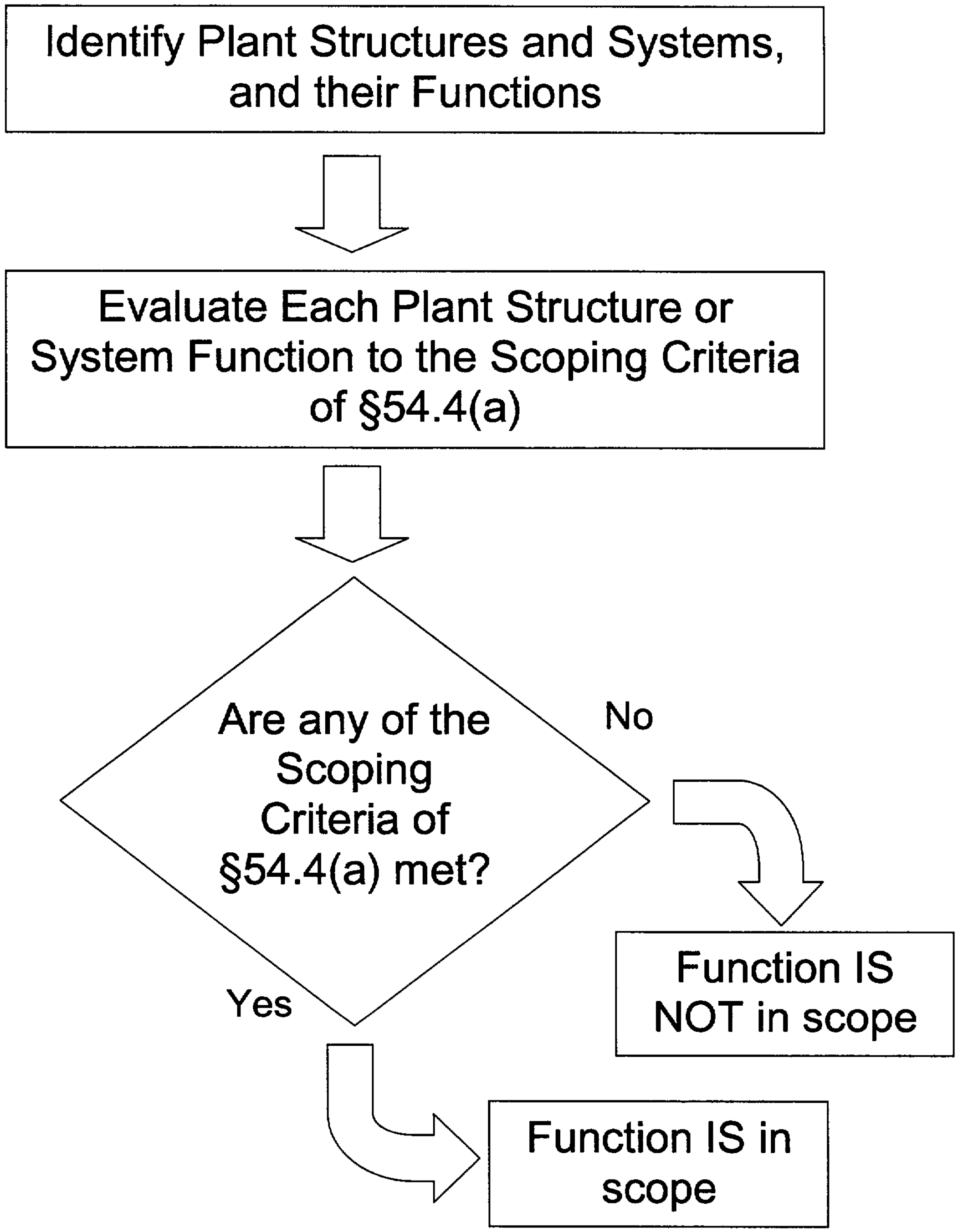


Figure 2.1.2-1 Process Flow Diagram For Plant Hatch License Renewal Scoping

2.1.2.2 System/Structure Function Identification

SNC performed a comprehensive review of design documents in order to create a list of systems and structures to be scoped. Information sources included the Plant Hatch Equipment Location Index (ELI) listing of system and structure nomenclature used at the plant, the Plant Hatch Maintenance Rule Scoping Manual, the Plant Hatch System Evaluation Document (SED), and the Plant Hatch Final Safety Analysis Reports (FSAR). In addition, a plant design drawing which lays out a generic listing of system nomenclature for boiling water reactors (BWR) was reviewed in order to thoroughly identify all potential system/structure identifiers (MPL numbers). The resultant list of potential systems and structures provided a starting point for system and structure function identification.

The scoping requirements of the Rule and the Maintenance Rule overlap. The requirements [10 CFR 54.4(a)(1) and 10 CFR 50.65(b)(1), respectively] for identifying safety-related system and structure functions are similar. In addition, the requirement in 10 CFR 54.4(a)(2) for identifying nonsafety-related system and structure functions within the scope of the Rule is similar to the corresponding requirement [10 CFR 50.65(b)(2)(ii)] in the Maintenance Rule except for issues such as Seismic II/I considerations. Because of the similarities in the rules, the Plant Hatch Maintenance Rule Scoping Manual was one of the information sources used to establish an initial listing of plant system and structure functions.

The final list of functions evaluated encompasses all plant systems and structures, except as described in Section 2.1.2.3. The functions did not necessarily follow traditional system boundaries, in that the functions included structures and components, irrespective of traditional system nomenclature, that perform or support the identified function.

The Rule is a component-based rule. That is, an aging management evaluation down to the component level is required. In addition, the Rule is function oriented. To arrive at the component level, SNC chose to scope at a function level and screen at the component level. SNC has elected to use the term "component function" when referring to the specific structure, component, or component group functions needed to support an intended function. Table 2.1-2 is a listing of component functions defined and used by the Plant Hatch application methodology. Components, component groups, and component functions are addressed in more detail in Section *2.1.3.2*.

2.1.2.3 Excluded Systems and Structures

The list of plant system and structure functions is intended to be comprehensive. However, processing every aspect of the plant was beyond the intent of the Rule. Some practical considerations were employed in the scoping process. That is, some facilities, structures, and equipment were excluded using expert judgment. Examples of excluded facilities, structures, and equipment include the following:

- Driveways and parking lots that provide access to and from various areas of the plant.
- Office and warehouse facilities.
- Temporary equipment.
- Health physics equipment.
- Portable radios.
- Portable measuring and testing equipment and tools.

- Spare parts (however, staged equipment is not excluded from scoping).
- Motor vehicles.

In the Statements of Considerations, the NRC determined that regulatory requirements provide reasonable assurance that an acceptable level of emergency preparedness exists at any operating reactor at any time in its operating lifetime. Similarly, in the Statements of Considerations, the NRC determined that regulatory requirements for physical protection provide reasonable assurance that an adequate level of physical protection exists at any operating reactor at any time in its operating lifetime. For those reasons, the Statements of Considerations indicated the Commission will make no new finding on emergency preparedness or physical protection (security) as part of a license renewal decision. Thus, Plant Hatch systems and structures that only provide emergency preparedness or physical protection functions were not evaluated in the Plant Hatch scoping process.

2.1.2.4 Safety-Related Systems and Structures

10 CFR 54.4(a)(1)(i, ii, and iii) provide the scoping criteria for determining the functions of safety-related systems and structures that are within the scope of the Rule. Each system and structure function in the plant listing of scoping results (Table 2.2-1) was reviewed with respect to these requirements by addressing the following questions:

- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the integrity of the reactor coolant pressure boundary?
- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition?
- Is the system or structure function identified as safety related because it is relied upon during and following design basis events to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 100.11?

Engineering and licensing documents were used to answer these questions. The ELI and the SED are engineering documents that provide system-related design information. The FSARs, the Maintenance Rule Scoping Manual, and the SED provide function-related information. The FSARs and applicable references identify the basis for Plant Hatch design basis events.

If the answer to one or more of the three questions was "YES," the corresponding system or structure function was determined to be within the scope of the Rule and was designated as an intended function as identified by 10 CFR 54.4(b).

SNC, in certain cases, has conservatively chosen to designate some systems whose functions may not meet any of the scoping criteria of 10 CFR 54.4(a)(1) as safety related. In such cases, the inscope determination may indicate that the system function does not meet the scoping criteria of 10 CFR 54.4(a)(1). System functions brought into scope by 10 CFR 54.4(a)(1) were also reviewed to determine whether they were also in scope based on the requirements of 10 CFR 54.4(a)(2) or 10 CFR 54.4(a)(3). In addition, functions may include, in a few cases, both safety-related and nonsafety-related components. In those cases, a function would be identified as meeting the scoping criteria of 10 CFR 54.4(a)(1) as well as the requirement for 10 CFR 54.4(a)(2), as described in the following Section.

2.1.2.5 Nonsafety-Related Systems and Structures Whose Failure Could Prevent Safety-Related Systems and Structures from Accomplishing Their Function

The scoping criterion at 10 CFR 54.4(a)(2) was used to identify the functions of nonsafety-related systems and structures that are within the scope of the Rule. 10 CFR 54.4(a)(2) provides that "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 Section 54.4 are within the scope of the Rule. Few system and structure functions at Plant Hatch satisfy the criterion because systems and structures supporting safety-related systems and structures were typically designed as safety-related. Each system and structure function in the plant listing of scoping results was reviewed with respect to this requirement by addressing the following question:

- Is the system or structure function identified as nonsafety related whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i, ii, and iii)?

Engineering and licensing documents were used to answer this question. The ELI and the SED were used to provide system-related design information. The FSARs, the Maintenance Rule Scoping Manual, and the SED were used to provide function-related information. The FSARs and applicable references were used to identify the basis for Plant Hatch design basis events.

Based upon a review of the Plant Hatch Final Safety Analysis Reports, issues or events considered in association with this question for Plant Hatch were Seismic II/I, flooding, jet impingement, pipe whip, and missiles.

If a function was used to mitigate one or more of the issues or events, the answer to the above question was "YES," the corresponding system or structure function was brought inscope, and the function was identified as an intended function per 10 CFR 54.4(b). In making determinations associated with this question, SNC also relied on the consideration of actual plant-specific experience, industrywide operating experience, and existing plant-specific engineering evaluations that were originally addressed by the controlled Maintenance Rule Scoping Manual determinations. Consistent with the Statements of Considerations, hypothetical failures that result from postulated system functional interdependencies that are not part of the Plant Hatch safety analyses or effects evaluations and that have not been observed at Plant Hatch were not considered.

2.1.2.6 Systems and Structures Relied Upon to Demonstrate Compliance With Certain NRC Regulations

SNC reviewed NRC Safety Evaluation Reports (SERs) and related docketed correspondence associated with four of the five regulations called out in 10 CFR 54.4(a)(3). SNC used this review to identify the set of system and structure functions credited with satisfying the requirements associated with those regulations from the complete set of system and structure functions established by the process described in Section 2.1.2.2. The four regulations are as follow:

- 10 CFR 50.48, "Fire protection."
- 10 CFR 50.49, "Environmental qualification of electric equipment important to safety for nuclear power plants."

- 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants."
- 10 CFR 50.63, "Loss of all alternating current power."

An additional regulation, 10 CFR 50.61, "Fracture toughness requirements for protection against pressurized thermal shock events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154 (Ref. 7) for boiling water reactor plants is not required.

Each system and structure function was reviewed with respect to these criteria by addressing the following questions:

- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for fire protection (10 CFR 50.48)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for environmental qualification (10 CFR 50.49)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for ATWS events (10 CFR 50.62)?
- Is the system or structure function relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for SBO (10 CFR 50.63)?

The Environmental Qualification Master List (EQML) was used to identify the systems relied upon to comply with 10 CFR 50.49. For the second question, if system or structure components were listed in the EQML, then the system or structure function(s) that required environmental qualification of the components was designated as being relied upon to demonstrate compliance with 10 CFR 50.49. These system or structure functions were brought in scope and they were identified as intended functions per 10 CFR 54.4(b).

During the review of the EQML, NRC SERs, and docketed correspondence, SNC confirmed that any credited functions and the systems and structures that specifically contribute to accomplishing the functions were included in the list of system or structure functions.

For the remaining questions, regarding the fire protection, ATWS, and station blackout regulations, if the answer to any of the questions was "YES," then the corresponding system or structure function(s) was brought into scope and the function(s) was identified as an intended function per 10 CFR 54.4(b). The NRC SERs and associated docketed correspondence were used to answer these questions.

References to a system, structure, or function in a SER or docketed correspondence were evaluated to determine whether the system, structure, or function was required to comply with the regulation. Functions and the associated systems and structures were excluded if they were not specifically used in the analyses or evaluations to assure compliance with the regulation. In addition, consistent with the Statements of Considerations III(c)(iii), new evaluations which consider additional systems and structures required to support operability of these systems and structures were not performed, nor was consideration taken of hypothetical failures that could result from system interdependencies that are not part of the Plant Hatch safety analyses and have not been previously experienced at Plant Hatch.

2.1.3 CIVIL/MECHANICAL COMPONENT SCREENING

The Rule requires a review of plant systems, structures, and components to determine if the effects of aging are adequately managed for certain structures and components in the period of extended operation. The process described in Section 2.1.2 was used to identify the Plant Hatch intended functions, that is, those system, structure, and component functions that are within the scope of the Rule. The Rule then requires, at 10 CFR 54.21(a), that an integrated plant assessment process be applied to systems, structures, and components determined to be in scope per 10 CFR 54.4. The integrated plant assessment process employed by SNC required an initial review of those functions within the scope of the Rule, as determined by the process described in Section 2.1.2, to define intended function evaluation boundaries. The intended function evaluation boundaries were then used to assist in the identification of the structures and components that are subject to an aging management review. That portion of the integrated plant assessment which describes the process used to identify civil/mechanical structures and components subject to an aging management review (screening) is described in this Section. Section 2.1.4 describes the screening of electrical components.

The Rule, at 10 CFR 54.21(a)(1), requires applicants to identify and list the structures and components subject to an aging management review. This section defines a "screening" process whereby SNC identified and listed the structures and components which met the criteria of 10 CFR 54.21(a)(1)(i) and (ii). Use of the term "passive" within this application is intended to be identical to criterion (i). That is, structures and components that perform an intended function without moving parts or without a change in configuration or properties are characterized in this document as "passive." Likewise, as set forth in criterion (ii), structures and components that are not subject to replacement based on a qualified life or specified time period are characterized in this document as "long-lived."

SNC performed screening of the civil/mechanical intended functions for Plant Hatch in two steps:

1. Evaluation boundaries were established for each intended function; and
2. Passive, long-lived components were identified within each evaluation boundary.

The screening process first established an evaluation boundary to define the systems or structures that are required to accomplish an intended function. Then each evaluation boundary was used to assist in identification of the complete set of structures and components within the evaluation boundary and to identify the passive, long-lived subset that represents those structures and components subject to an aging management review. This final set of structures and components is presented in the tables in Sections 2.3 through 2.5 in fulfillment of the requirement of 10 CFR 54.21(a)(1).

2.1.3.1 Intended Function Evaluation Boundaries

This step of the screening process defines the evaluation boundary for the system and structure functions determined to be within the scope of the Rule by the process described in Section 2.1.2. These functions are the intended functions per the definition in the Rule at 10 CFR 54.4(b). Defining the evaluation boundary focuses the screening process on the portions of systems and structures that contribute to the performance of one or more intended functions. Evaluation boundaries were established such that multiple, inscope functions are included in one evaluation boundary description to the extent practical. Evaluation boundaries were produced using controlled procedures to assure a consistent approach to preparation and documentation.

Evaluation boundaries, as used in this methodology, were not required to match other boundaries that are defined in existing documents such as the FSARs or plant piping and instrumentation diagrams. Defining evaluation boundaries for license renewal does not require the plant to change or redefine other existing boundaries such as pipe class design boundaries or In-Service Inspection and Testing boundaries. In addition, where a functional boundary was defined in the CLB for an inscope function, the CLB-defined boundary was used. SNC chose to conservatively designate certain components as "in scope" more broadly than the rule might otherwise require. In such cases, the intended function evaluation boundaries do not redefine the CLB.

The method of describing the evaluation boundary relied primarily on plant drawings. The set of drawings that were most appropriate to illustrate the boundary information was marked up with boundary designations that clearly indicate which portions or areas of the system are inside and which portions are outside the evaluation boundary. For example, system piping and instrumentation diagrams (P&ID) were typically used to illustrate the evaluation boundary of intended functions from a mechanical perspective.

Due to the nature of civil/structural functions, evaluation boundary drawings were not produced for intended functions associated with structures; piping, cable tray, and conduit supports; electrical panel and rack supports; secondary containment doors; cranes; tornado vents; and penetrations. Instead, a plan view of the plant site was produced to identify the inscope structures. The evaluation boundary of a structure that is a building included the entire building, including slabs, external and internal walls, roof and internal concrete, steel columns and beams, and framing. Miscellaneous steel items, such as base plates and embedded plates, were also included.

In the process of defining evaluation boundaries, emphasis was placed on assuring all interfaces were adequately considered. As necessary, other references, prepared lists, and written descriptions were used to supplement or further clarify the boundary designations on the marked-up drawings. The final set of illustrated mechanical and electrical drawings, references, and written descriptions formed the "boundary package" for an intended function and was documented by controlled procedures.

In order to maintain a consistent approach to screening, general and specific discipline interface guides were established and used to assist in designating the intended function evaluation boundaries and interfaces. The guidelines were incorporated into a controlled procedure for component screening. The guidance was not established, however, as a set of rigid requirements. Specific cases were dispositioned on the basis of producing a conservative boundary.

The SNC screening process first defined civil/mechanical evaluation boundaries for intended functions. Then, all components included in the evaluation boundary were grouped, when practical, and screened. This approach differs from NEI 95-10, Revision 0, which establishes groupings after the screening process is completed.

2.1.3.2 Component Types, Component Groups, and Component Functions

Table 2.1-1 lists component types that are in scope for license renewal at Plant Hatch. This table is based on a table that originated as Appendix B of NEI 95-10, Revision 0. That listing was revised and expanded by the NEI License Renewal Task Force to include component types, mostly electrical, that were omitted from the original Appendix B. During the process of screening structures and components at Plant Hatch, additional component types were identified and are included in Table 2.1-1.

The list in Table 2.1-1 represents the plantwide list of inscope structures and components, by component type. The tables in Sections 2.3 through 2.5 present the screening results arranged by plant system or structure member. Each component type listed in the tables in sections 2.3 through 2.5 is a passive component as determined in Table 2.1-1.

Although not required by the Rule, in order to more efficiently screen structures and components, component types within each intended function evaluation boundary were grouped to the maximum extent practicable. In creating these component groups, only components of the same type were grouped together. That is, a component group of valves did not include pipe. In addition, only component types within each intended function evaluation boundary that were fabricated of similar materials, and which were subjected to similar environments were grouped. For example, stainless steel valves were not grouped with carbon steel valves, and piping with an internal environment of reactor coolant water was not grouped with raw water piping.

Structural or mechanical components included in each component group were identified and documented by one or a combination of the following methods:

- By establishing a list of the MPL numbers;
- By listing the reference drawings; or
- By describing the component or system.

When establishing a passive and long-lived component group, specific information required to accurately describe the component function(s), materials composition, and internal and external environments for the components included in the component group was recorded in the screening records. In addition, the applicable drawings, system descriptions, design information, material specifications, and/or other information that could aid in performing an aging management review was documented to the extent necessary to accurately and efficiently screen a component group.

Component types that did not fit into a component group were recorded separately. In only a few instances, a component group was not created because the component being screened was unique; that is, only one component of the component type being evaluated was found in license renewal scope within the evaluation boundary. The information recorded for these passive and long-lived components and component types included a component function(s), the material designation(s), internal/external environmental conditions, pertinent design information, and pertinent drawings/documents that could aid in performing an aging management review.

Component function(s) for component types subject to an aging management review were established on the basis of how the structure or component functions to support maintaining one or more intended functions consistent with the CLB, without reliance on redundancy or probabilistic considerations. Table 2.1-2 provides the list of component functions used in the structure and component screening at Plant Hatch. This table expands on the list of component functions originally presented in NEI 95-10, Revision 0.

2.1.3.3 Passive Structures, Components, and Component Groups

Having considered the effectiveness of existing plant programs which monitor the performance and condition of systems, structures, and components that perform active functions, the NRC concluded in the Statements of Considerations that active components can be excluded from a license renewal aging management review. This exclusion from license renewal review is because functional degradation resulting from the effects of aging on active components is more readily determined, and existing programs and requirements are expected to directly detect and correct the effects of aging.

Table 2.1-1 presents the active/passive determination made for each inscope component type. The "Determination Basis" column identifies the source, or basis, for the active/passive determination. For those component types that were added to the list during the Plant Hatch screening activity, the basis for the determination is contained in internal documentation and is not presented in the application. Some active/passive determinations presented in Table 2.1-1 are different from the determination presented in Appendix B of NEI 95-10, Revision 0. The Appendix B list indicated the component type to be passive when any aspect of the component's function was subject to an aging management review. Table 2.1-1 presents the determinations in a different way. The nature of the component type is identified in the active/passive determination. For example, a valve is active since movement is required for it to perform its function. Similarly, a door is active since it is designed to open and close. However, when certain features of the component require evaluation, those features are listed parenthetically with the component type label. Specific examples include "bodies only" for valves, "casings only" for pumps, and "pressure boundary only" or "structural integrity only" for numerous component types.

The SNC process defined evaluation boundaries for intended functions associated with structures and screened the boundaries to identify the passive and long-lived elements of the structures. Figure 4.1-1 of the NEI 95-10, Revision 0, guideline excludes structures from the active/passive and long/short-lived component determination process since structural components are generally passive and long-lived. As a matter of convenience, SNC did not make this distinction in the screening of structural components. Although intended function evaluation boundary drawings were not produced for the structures, the structural components screening included the active/passive and long/short-lived determinations as a matter of completeness and to facilitate the aging management reviews.

2.1.3.4 Components Subject to Periodic Replacement at a Set Frequency or Qualified Life

The detrimental effects of aging are assumed to be continuous and incremental. Thus, the detrimental effects of aging may increase as service life is extended, assuming no replacement of components. One way of effectively managing these effects is to replace selected structures and components on a specified time interval, based upon a qualified life of the structure or component. Consistent with the Statements of Considerations of the Rule, it is not necessary to justify or prove that the frequency of replacement is adequate since the existing regulatory processes are credited with ensuring their adequacy.

In this step of the screening process, the passive structures and components were reviewed to determine if they are subject to replacement based upon a specified time or qualified component life. Structures and components that are not subject to such replacement were classified as "long-lived." In the methodology employed by SNC, a replacement life must be less than 40 years for the structure or component to be considered "short-lived." Structures and components with replacement lives of 40 years or greater were considered "long-lived." Structures and components subject to replacement based on qualified life were identified as not being subject to aging management review.

2.1.4 ELECTRICAL COMPONENT SCREENING

This section provides the methodology used for screening of electrical components in accordance with the requirements of the Rule. The purpose of this section is to identify the electrical and I&C components at Plant Hatch which require an AMR for license renewal. This section of the Plant Hatch scoping methodology describes and justifies how the list of electrical components which require an AMR was determined. The process employed in electrical component screening is intended to identify all electrical components in the plant which require an aging management review.

2.1.4.1 Identification of Electrical Components Subject to an Aging Management Review

The process used to identify electrical components subject to an aging management review is different from the method used to identify civil and mechanical components subject to an aging management review. Electrical screening was based on the premise that the majority of electrical components installed in the plant perform their function with moving parts or a change in configuration or properties, and are therefore not subject to an aging management review per the Rule. The electrical screening process was accomplished using the following steps:

1. Develop a comprehensive list of all electrical component types installed in the plant without regard for system function or license renewal inscope status.
2. Determine the basic function each component type performs.
3. Determine which component types perform their function without moving parts or a change in configuration or properties. This results in the list of electrical component types which are subject to an aging management review for license renewal.
4. Apply the scoping criteria of 10 CFR 54.4(a)(1) through (3) to the list of component types which meet the screening criteria to determine if the list of electrical component types requiring an aging management review can be further reduced.

List of Installed Component Types

In order to screen electrical component types to determine those which require an aging management review, a complete list of all electrical component types installed in the plant was required. This list was compiled using the lists of components found in 10 CFR 54.21(a)(1)(i) and NEI 95-10, Appendix B, as the starting point. The NEI 95-10 list was further evaluated and refined by industry working groups. The resulting list of components was evaluated by plant engineering personnel and system experts who used their knowledge of plant systems and drawings to ensure that the list was complete and contained all electrical component types in use at Plant Hatch. Some component types with similar functions were grouped together for simplicity. This process provides reasonable assurance that the list of electrical component types installed in the plant is accurate and complete. The in scope electrical component types installed at Plant Hatch are included in the Table 2.1-1 list. The list of electrical component types subject to an aging management review appears in Table 2.5.15-1.

Application of 10 CFR 54.21 Screening Criteria to Electrical Component Types

Having compiled the electrical component type list, the 10 CFR 54.21 criteria were applied to determine which component types are subject to an aging management review. The screening criteria of 10 CFR 54.21(a)(1)(i) and (ii) were applied to the comprehensive list of electrical component types to accomplish this step. Components for which both criteria are "YES" are subject to an aging management review. These screening criteria are as follow:

- 10 CFR 54.21(a)(1)(i) – The component performs an intended function as described in 54.4 without moving parts or without a change in configuration or properties;
- 10 CFR 54.21(a)(1)(ii) – The component is not subject to replacement based on a qualified life or a specified time period.

An active/passive determination in accordance with 10 CFR 54.21(a)(1)(i) was documented for each type of electrical component installed at Plant Hatch. This determination is presented in Table 2.1-1. The bases for these active/passive screening determinations are provided as a footnote to the table.

When implementing the screening criteria of 10 CFR 54.21(a)(1)(ii), except for those cases where a determination was made for individual components (e.g., components qualified pursuant to 10 CFR 50.49), the determination was made for an entire component type or commodity group.

Individual components within the scope of the EQ program fall into two categories: those with a qualified life of 40 years or greater which are covered by a TLAA, and those with a qualified life of less than 40 years and are therefore subject to replacement based on a specified time period. The components with qualified lives of less than 40 years are currently on a replacement schedule which will continue into the renewal term; these components are not subject to an AMR. The qualified life calculations of those components with qualified lives greater than 40 years are treated as TLAAs and are evaluated in Section 4. These TLAAs are dispositioned in accordance with the applicable disposition method per the Rule. In cases where a particular TLAA cannot be extended to 60 years, those components will be replaced or refurbished in accordance with the requirements of the EQ program. Therefore, no components included in the EQ program are subject to an AMR.

Application of 10 CFR 54.4 Scoping Criteria to Electrical Component Types

Scoping was performed as described in Section 2.1. The set of passive, long-lived component types derived from the process described in Section 2.1.4.1, steps 1 through 3, was then evaluated to the scoping criteria stated in step 4. This step was performed to further define the set of electrical component types subject to aging management review.

The set of electrical component types remaining after steps 1 through 4 of the screening process are included in the list in Table 2.1-1 of Plant Hatch component types subject to aging management review.

2.1.5 DOCUMENTATION

Section 54.37(a) of the Rule requires all information and documentation required, or otherwise necessary, to document compliance with the provisions of the Rule to be retained in an auditable and retrievable form.

Paragraphs 10 CFR 54.21 and 54.37 detail the requirements of the Rule for documenting the IPA process. SNC has complied with these Rule requirements in the preparation of this application.

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations

Component Type	Passive	Determination Basis[1]
Air Compressor	No	1
Alarm Unit	No	2
Analyzers	No	2
Annunciators	No	2
Batteries	No	1
Battery Chargers	No	1
Cable Trays and Supports	Yes	1
Cables	Yes	1
Circuit Breakers	No	1
Controllers – Differential Pressure Indicating Controller	No	2
Controllers – Flow Indicating Controller	No	2
Controllers – Manual Loader	No	6
Controllers – Other	No	2
Controllers – Programmable Logic Controller	No	6
Controllers – Single Loop Digital Controller	No	6
Controllers – Speed Controller	No	2
Controllers – Temperature Controller	No	2
Controllers – Valve Positioner	No	6
Converters – Amp Transducer	No	6
Converters – Current/Pneumatic Converter	No	6
Converters – Frequency Transducer	No	6
Converters – Other	No	6
Converters – Power Factor Transducer	No	6
Converters – Signal Converter	No	6
Converters – Signal Selector, Hi/Lo	No	6
Converters – Speed Transducer	No	6
Converters – Square Root Extractor	No	6
Converters – Summer	No	6
Converters – VAR Transducer	No	6
Converters – Vibration Transducer	No	6

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Converters – Voltage Transducer	No	6
Converters – Voltage/Current Converter	No	2
Converters – Voltage/Pneumatic Converter	No	2
Converters – Watt Transducer	No	6
Dampers	No	1
Doors, controlled leakage and fire-rated barriers (pressure boundary, structural integrity)	No	2
Electric Heaters (pressure boundary only)	No	3
Electrical Connectors	Yes	1
Electrical Panels, Racks, Cabinets, & Other Enclosures (structural integrity only)	No	1
Electronic Devices	No	6
Emergency Diesel Generators	No	1
Emergency Lighting	No	2
Fan-Coil Unit	No	5
Fans – Ventilation Fans	No	1
Fire Barriers	Yes	2
Fire Pump Diesel Engines	No	1
Flexible Connectors	Yes	2
Fuel Assemblies	No	5
Fuel Pool and Sump Liners	Yes	1
Fuses	No	4
Grounding	Yes	6
Hangers and Supports, ASME Class 1	Yes	1
Hangers and Supports, Non-ASME Class 1	Yes	1
Heat Exchangers	Yes	1
Heat Tracing	No	3
Hose Stations	Yes	2
Indicators – Ammeter	No	2
Indicators – Conductivity Meter	No	6
Indicators – Differential Pressure Indicator	No	1
Indicators – Flow Indicator	No	2

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Indicators – Frequency Meter	No	6
Indicators – Level Indicator	No	1
Indicators – Other	No	6
Indicators – Power Factor Meter	No	6
Indicators – Pressure Indicator	No	1
Indicators – Speed Indicator	No	2
Indicators – Temperature Indicator	No	2
Indicators – VAR Meter	No	6
Indicators – Vibration Indicator	No	6
Indicators – Volt Meter	No	6
Indicators – Watt Meter	No	6
Indicators – Watthour Meter	No	6
Installed Communication Equipment	No	5
Instrument Racks, Frames, Panels, & Enclosures (structural integrity only)	No	1
Insulation, Thermal	Yes	5
Isolators	No	2
Joints and Seals, Compressible	Yes	2
Local Starter	No	2
Magnetic Contactor	No	2
Motor-Generator Sets	No	2
Motors	No	1
Panels – Distribution Panel Internal Component Assemblies (structural integrity only)	No	2
Panels – Electrical Controls and Panel Internal Component Assemblies (structural integrity only)	No	2
Penetration Assemblies, Electrical and I&C	Yes	1
Penetration Seals	Yes	2
Penetrations – Nelson Frames	Yes	5
Phase Bussing – Isolated Phase Bus	Yes	5
Phase Bussing – Metal Enclosed Bus	Yes	5
Phase Bussing – Non-Segregated Phase Bus	Yes	5

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Phase Bussing – Other	Yes	5
Piping – Class 1 Piping Components	Yes	1
Piping – Non-Class 1 Piping Components	Yes	1
Power Distribution - AC Motor Control Center	No	2
Power Distribution - DC Motor Control Center	No	2
Power Distribution - Load Center	No	2
Power Distribution - Other	No	6
Power Distribution - Switchgear Unit	No	1
Power Supply	No	1
Pumps (casings only)	No	1
Reactor Vessel	Yes	2
Reactor Vessel Internals	Yes	2
Recombiners	No	5
Recorders	No	2
Refrigerant Condensing Unit	No	5
Regulators - Current Regulator	No	6
Regulators - Frequency Regulator	No	6
Regulators - Other	No	6
Regulators - Voltage Regulator	No	6
Relays - Auxiliary Relay	No	1
Relays - Control Logic Relay	No	1
Relays - Other	No	1
Relays - Protective Relay	No	1
Relays - Time Delay Relay	No	1
Restricting Orifices	Yes	2
Rupture Disks (pressure boundary)	No	2
Sensors - Conductivity Element (pressure boundary only)	No	2
Sensors - Flow Element (pressure boundary only)	No	2
Sensors - Moisture Sensor	No	6
Sensors - Other (pressure boundary only)	No	6
Sensors - Radiation Sensor (pressure boundary only)	No	2

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Sensors - Temperature Sensor (pressure boundary only)	No	2
Sensors - Vibration Probe (pressure boundary only)	No	6
Signal Conditioners	No	2
Smoke Detectors	No	6
Snubbers	No	1
Steam Traps (pressure boundary only)	No	2
Strainers	Yes	2
Structural Bellows	Yes	2
Structures - Category 1	Yes	1
Structures - Equipment Supports and Foundations	Yes	1
Structures - Non Category 1 Intake Structures	Yes	2
Structures - Offgas Stack and Flue	Yes	2
Structures - Other Non-Category 1 Structures	Yes	2
Structures - Primary Containment	Yes	1
Switches - Automatic Transfer Switch	No	1
Switches - Conductivity Switch	No	1
Switches - Control Switch	No	1
Switches - Current Switch	No	1
Switches - Differential Pressure Indicating Switch	No	1
Switches - Differential Pressure Switch	No	1
Switches - Flow Switch	No	1
Switches - Fusible Disconnect Switch	No	1
Switches - Knife Switch	No	1
Switches - Level Indicating Switch	No	1
Switches - Level Switch	No	1
Switches - Limit Switch	No	1
Switches - Manual Transfer and Disconnect Switch	No	1
Switches - Moisture	No	1
Switches - Other	No	1
Switches - Position Switch	No	1
Switches - Pressure Indicator Switch	No	1

Table 2.1-1 List of Structure and Component Types and Associated Active/Passive Determinations (Continued)

Component Type	Passive	Determination Basis[1]
Switches - Pressure Switch	No	1
Switches - Safety Switch	No	1
Switches - Temperature Indicating Switch	No	1
Switches - Temperature Switch	No	1
Switches - Vibration Switch	No	1
Tanks	Yes	2
Timers	No	6
Transformers - Instrument Transformer	No	3
Transformers - Load Center Transformer	No	3
Transformers - Other	No	6
Transformers - Small Distribution Transformer	No	3
Transmitters - Conductivity Transmitter	No	6
Transmitters - Differential Pressure Transmitter	No	1
Transmitters - Flow Transmitter	No	2
Transmitters - Level Transmitter	No	2
Transmitters - Other	No	6
Transmitters - Pressure Transmitter	No	1
Transmitters - Radiation Transmitter	No	2
Transmitters - Temperature Transmitter	No	6
Transmitters - Valve Position Transmitter	No	6
Tube Track	Yes	2
Turbines - Turbine Pump Drive Casings (excluding pumps)	Yes	2
Unit Heater	No	3
Valve (bodies only)	No	1
Valve Operators (hydraulic, motor, air, solenoid)	No	2

[1]**Determination Bases**

1. The Rule, at 10 CFR 54.21(a)(1)(ii), excludes a variety of electrical and I&C components from an aging management review. The specific items are listed in this section. If a determination for a particular component type is presented in the Rule, no further evaluation is deemed necessary.
2. NEI 95-10 provides an active/passive determination for many of the items on the list. This information has been previously reviewed and approved by industry groups; if a determination for a particular component type is presented in NEI 95-10, and this determination has been accepted by the industry and the Nuclear Regulatory Commission, no further evaluation is deemed necessary.
3. The letter from the Nuclear Regulatory Commission to the Nuclear Energy Institute dated September 19, 1997, provided evaluations for transformers, heat tracing, electric heaters, indicating lights, and recombiners.
4. The letter from the Nuclear Regulatory Commission to the Nuclear Energy Institute dated April 27, 1999, provided clarification of the status of fuses and is used as the basis for the determination that fuses do not require an aging management review.
5. Plant-specific evaluations were performed for these component types.
6. Certain components listed on Table 2.1-1 are variations of equipment evaluated by NEI 95-10 or listed in 10 CFR 54.21(a)(1)(i). These components perform the same basic function as those that are evaluated and have the same active/passive determination as the listed components.

Table 2.1-2 List of Component Functions

Label	Description
1. Debris Protection	Provide protection from debris
2. Environmental Control	Provide environmental control of plant areas not to exceed equipment limitations
3. Exchange Heat	Provide exchange of heat from one fluid medium to another
4. Fire Barrier	Provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
5. Fission Product Barrier	Provide pressure boundary or fission product retention barrier to protection public health and safety in the event of any postulated DBEs
6. Flood Barrier	Provide flood protection barrier (internal and external flooding event)
7. Flow Direction	Provide spray shield or curbs for directing flow
8. Flow Distribution	Provide flow pattern or distribution
9. Flow Restriction	Provide flow restriction or pressure reduction or fixed throttling of process flow
10. HE/ME Shielding	Provide shielding against high energy line breaks and moderate energy line cracks credited in the CLB
11. Insulation Resistance	Provide insulation resistance to preclude shorts/grounds and unacceptable leakage current
12. Missile Barrier	Provide missile barrier (internally or externally generated)
13. Non-S/R Structural Support	Provide structural support to nonsafety-related components whose failure could prevent satisfactory accomplishment of any of the required safety-related functions
14. Pipe Whip Restraint	Provide pipe whip restraint
15. Pressure Boundary	Provide pressure retaining boundary so that sufficient flow and adequate pressure is delivered
16. Radiation Shielding	Provide shielding against radiation
17. Shelter/Protection	Provide shelter/protection to safety-related components
18. Structural Support	Provide structural support to safety-related components

2.2 SCOPING RESULTS

Table 2.2-1 presents the results of the Plant Hatch plantwide scoping of systems/structures and functions. Each function is identified as either in scope or not in scope. Due to the cross-system nature of functions, each function has been assigned to a primary system or structure. However, in many cases the functional boundaries extend into other systems or structures as well. As was described in the scoping/screening methodology, Section 2.1, screening of structures/components was performed within functional boundaries. Structures or other features not bearing a system number were assigned to a system or structure and scoped with that system or structure.

For each system/structure entry in Table 2.2-1 with at least one "inscope" function (these are the intended functions), narrative discussion is provided in Section 2.3, Section 2.4, or Section 2.5. These sections are arranged by mechanical, civil/structural, and electrical disciplines. As background information, a general system description is provided. The narrative also lists the intended functions that were evaluated to identify the set of components supporting those intended functions. Finally, each narrative presents a table of component groups requiring an aging management review. These tables identify and list the structures and components subject to aging management review, as stipulated in 10 CFR 54.21(a)(1). No discussion of systems, structures, functions, or components not in scope is provided in the narratives and tables of Sections 2-3 through 2-5.

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results

System Number	System Name	In Scope	Function Number/Name
A70	Analog Transmitter Trip System	Yes	A70-01 Process Parameter Monitoring
A71	Nuclear Steam Supply Shutoff	Yes	A71-01 Signal Transmission
B11	Reactor Assembly	Yes	B11-01 Nuclear Boiler
		Yes	B11-02 Reactivity Control
B21	Nuclear Boiler System	Yes	B21-01 Pressure Control
		Yes	B21-02 Reactor Coolant Pressure Boundary Integrity
		Yes	B21-03 Rod Worth Minimizer
		Yes	B21-04 Nuclear Boiler Instrumentation
B31	Reactor Recirculation	No	B31-01 Reactivity Control
		Yes	B31-02 RPT Breaker Trip
		Yes	B31-03 Reactor Coolant Pressure Boundary Integrity
C11	Control Rod Drive	No	C11-01 Normal Control Rod Movement
		No	C11-02 Vessel Injection
		No	C11-03 Control Rod Cooling
		Yes	C11-04 Reactivity Control (Reactor Scram)
		No	C11-05 Alternate Boron Injection
		No	C11-06 Pump Seal Purge
		Yes	C11-07 Alternate Rod Insertion (ARI)
C32	Feedwater Control	No	C32-01 Regulate Feedwater Flow to Vessel
C41	Standby Liquid Control	Yes	C41-01 Reactivity Control
		No	C41-02 Vessel Injection
		Yes	C41-03 SBLC Testing
		No	C41-04 SBLC System Draining
C51	Neutron Monitoring System	No	C51-01 Reactivity Monitoring
		No	C51-02 Rod Block Monitor
		No	C51-03 Traversing Incore Probe
C61	Primary Containment Isolation	Yes	C61-01 Primary Containment Isolation & Integrity
		Yes	C61-02 Signal Transmission

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
C71	Reactor Protection System	Yes	C71-01 Reactivity Control
		Yes	C71-02 Power Supply
C82	Remote Shutdown	Yes	C82-01 Alternate Control Room
C91	Process Computer	No	C91-01 Plant Parameter Monitoring
D11	Process Radiation Monitoring	Yes	D11-01 Main Steam Line Radiation Monitoring
		No	D11-02 Filter Performance Radiation Monitoring
		No	D11-03 Primary Containment Fission Product Radiation Monitoring
		No	D11-04 Primary Containment Gamma Radiation Monitoring (Narrow Range)
		No	D11-05 Sump Radiation Monitoring
		Yes	D11-06 Primary Containment Gamma Radiation Monitoring (Wide Range)
		No	D11-07 Off-Gas Radiation Monitoring
		No	D11-08 Liquid Process Radiation Monitoring
		No	D11-09 Main Stack Radiation Monitoring
		No	D11-10 Recombiner Building Radiation Monitoring (Unit 1)
		No	D11-11 Reactor Building Vent Stack Radiation Monitoring
		Yes	D11-12 Reactor Building Ventilation Radiation Monitoring
		Yes	D11-13 MCR Air Intake Radiation Monitoring
		Yes	D11-14 Refueling Floor Ventilation Radiation Monitoring
D21	Area Radiation Monitoring	No	D21-01 Radiation Monitoring and Indication
D31	Counting Room Equipment	No	D31-01 Sample Evaluation
D40	Instrument Calibration and Decon Room	No	D40-01 Instrument Maintenance

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
E11	Residual Heat Removal (RHR)	Yes	E11-01 LPCI
		Yes	E11-02 Containment Sprays
		No	E11-03 Suppression Pool Draining
		Yes	E11-04 RHRSW Vessel/Containment Injection
		Yes	E11-05 Shutdown Cooling
		No	E11-06 Fuel Pool Cooling Assist
		No	E11-07 Reactor Vessel Draining
		Yes	E11-08 Suppression Pool Cooling
		No	E11-09 Steam Condensing[1]
		Yes	E11-10 Alternate Shutdown Cooling
E21	Core Spray System	Yes	E21-01 Core Cooling
		No	E21-02 Primary Containment Flooding
		No	E21-03 Torus Fill
		Yes	E21-04 Alternate Shutdown Cooling
		Yes	E21-05 ECCS Keep Fill
E32	MSIV Leakage Control (Unit 2 only)	No	E32-01 Indirect Radioactive Release Control[1]
E41	High Pressure Coolant Injection (HPCI)	Yes	E41-01 Core Cooling
		No	E41-02 Alternate Boron Injection
		No	E41-03 Alt Press Control/Alt Depress
		No	E41-04 RPV Venting
		No	E41-05 Testing of HPCI Pump
E51	Reactor Core Isolation Coolant (RCIC)	Yes	E51-01 Core Cooling
		No	E51-02 Alt Press Control/Alt Depress
		No	E51-03 Alt. Boron Injection
		No	E51-04 RPV Venting
		No	E51-05 Steam Condensing[1]
		No	E51-06 Testing of RCIC Pump
F11	Fuel Servicing Equipment	No	F11-01 New Fuel Handling/Preparation
F13	Reactor Vessel Servicing Equipment	No	F13-01 Tools for Vessel Disassembly/Reassembly
F14	Reactor In Vessel Servicing Equipment	No	F14-01 Tools for Internal Vessel Disassembly/Reassembly

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
F15	Refueling Equipment	Yes	F15-01 Fuel/Control Rod Handling
F16	Fuel Storage Equipment	No	F16-01 Storage Racks[2]
F17	Under Reactor Vessel Servicing Equipment	No	F17-01 CRD Service
F41	Startrec	No	F41-01 Startup Test Data Acquisition
G11	Radwaste	No	G11-01 Effluent Isolation
		No	G11-02 Liquid Radioactive Waste Processing
		No	G11-03 Solid Radwaste Processing
G13	Heat Trace	Yes	G13-01 Freeze Protection
G31	Reactor Water Cleanup (RWCU)	No	G31-01 Alternate Pressure Control
		No	G31-02 Reactor Water Level Control
		No	G31-03 Coolant Water Chemistry
G41	Spent Fuel Pool Cooling and Clean-up	No	G41-01 Fuel Pool Cooling/Clean-up
G51	Torus Drainage and Purification System	No	G51-01 Torus Water Quality Control/Torus Drainage
G71	Decay Heat Removal	No	G71-01 Fuel Pool and Reactor Cavity Cooling
H11	Main Control Room Panels	Yes	H11-01 Operator Information and Control
H12	Annunciators	No	H12-01 Alarm
H21	In Plant Auxiliary Control Panels	Yes	H21-01 Equipment Support & Integrity
		Yes	H21-02 Operator Information and Control
J11	Fuel	Yes	J11-01 Energy Source
		Yes	J11-02 Spent Fuel Fission Product Barrier
L35	Piping Specialties	Yes	L35-01 Pipe Supports
		Yes	L35-02 Non-Seismic Pipe Supports
		No	L35-03 Miscellaneous Piping and Test Connections
L36	Insulation	No	L36-01 Equipment and Piping Insulation-Inside Drywell
		Yes	L36-02 Piping Insulation-Outside Drywell
L48	Access Doors	Yes	L48-01 Containment Integrity
L51	Instruments	No	L51-01 Seismic Monitoring

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
L52	Loose Parts Monitoring	No	L52-01 RPV Vibration Monitoring (Unit 2 Only)
N11	Main Steam	No	N11-01 Steam Supply Piping
		No	N11-02 Branch Steam Supply Piping
N21	Condensate and Feedwater	No	N21-01 Reactor Coolant Make-up
N22	Auxiliary Drains and Vents	No	N22-01 Condensate Drains
N30	Turbine	No	N30-01 Energy Conversion
		No	N30-02 Pressure Control - Bypass Valves
N32	EHC	No	N32-01 Turbine Control
		Yes	N32-02 Main Turbine Pressure Regulator
N33	Steam Seals	No	N33-01 Sealing Steam to Valves and Turbines
		No	N33-02 Exhaust and Hold-up Volume
N34	Turbine Lube Oil	No	N34-01 Main Turbine Lift Pumps
		No	N34-02 Main Turbine Lube Oil
		No	N34-03 RFP Lube Oil
		No	N34-04 MG Set Lube Oil
		No	N34-05 Main Turbine Turning Gear Lube Oil
N36	Extraction Steam	No	N36-01 Steam Supply to Turbine Building Loads
N38	Main Steam Reheat (MSR)	No	N38-01 Steam Quality
N39	Turning Gear	No	N39-01 Turbine Rotation
N40	Generator	No	N40-01 Power Generation
N41	Generator Core Monitor	No	N41-01 Main Generator Insulation Monitoring
N42	Generator Hydrogen Seal Oil	No	N42-01 Maintain Generator Hydrogen Pressure
N43	Generator Stator Water Cooling	No	N43-01 Stator Cooling
N61	Main Condenser	No	N61-01 Heat Removal
		No	N61-02 Power Generation
		Yes	N61-03 Post Accident Radioactive Decay Holdup

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
N62	Off Gas	No	N62-01 Gaseous Radwaste Effluent Isolation
		No	N62-02 Process & Control The Release of Gaseous Radioactive Wastes
N71	Circulating Water	No	N71-01 Main Condenser Heat Removal
P11	Condensate Transfer & Storage	Yes	<u>P11-01</u> ECCS/CRD Condensate Supply
		No	P11-02 Condensate Transfer
P21	Demineralized Water	No	P21-01 Demineralized Water Supply to All Plant Loads
P23	Caustic/Acid	No	P23-01 Demin Resin Regeneration (Unit 1 Only)
P25	Amertap	No	P25-01 Condenser Tube Cleaning (Unit 1 Only)
P32	Nitrogen Blanketing	No	P32-01 Corrosion Protection
P33	Sampling System	Yes	<u>P33-01</u> Display of Hydrogen/Oxygen Information for Operator
		No	P33-02 Post Accident Sampling (PASS)
		No	P33-03 Radwaste Building Process Sampling
		No	P33-04 Reactor Building Process Sampling
		No	P33-05 Turbine Building Process Sampling
		No	P33-06 Drywell Oxygen Content
P41	Plant Service Water	Yes	<u>P41-01</u> Essential Mechanical/Environmental Support
		Yes	<u>P41-02</u> Turbine Building Isolation
		No	P41-03 Radwaste Dilution
		No	P41-04 Non-Essential Mechanical/Environmental Support
		Yes	<u>P41-05</u> 1B EDG Cooling (Standby PSW)
		No	P41-06 Circulating Water System Flume Make-up
P42	Reactor Building Closed Cooling Water (RBCCW)	Yes	<u>P42-01</u> Reactor Building Equipment Cooling
P44	Plant Hot Water Heating	No	P44-01 Reactor Building Climate Control
P50	SCBA Compressor Air	No	P50-01 Compressed Air Supply

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
P51	Station Service Air	No	P51-01 Compressed Air Supply
		No	P51-02 RWCU, FPC & Condensate Demin Low Pressure Air Blowers
P52	Instrument Air	Yes	P52-01 Non-Interruptible Essential Instrument Air Supply
		No	P52-02 Interruptible Essential Instrument Air Supply
P61	Auxiliary Boiler	No	P61-01 Start-up Steam Supply
P62	Environmental Monitoring	No	P62-01 River Influent/Effluent Monitoring
P63	Turbine Building Chillers	No	P63-01 Turbine Building Cooling
P64	Primary Containment Chilled Water (Unit 2)	No	P64-01 Reactor Building/Radwaste Building Cooling
		Yes	P64-02 Drywell Cooling
P65	Reactor Building Chilled Water	No	P65-01 Reactor Building Equipment/Area Cooling
P67	Control Building Chilled Water	No	P67-01 Chilled Water to Control Building HVAC
P70	Drywell Pneumatics	Yes	P70-01 Nitrogen Supply to Drywell Equipment
		No	P70-02 Containment Environment Control
P73	Hydrogen Water Chemistry	No	P73-01 IGSCC Mitigation
P85	Zinc Injection	No	P85-01 Inhibit Radiation Build-up
R13	Isophase Bus	No	R13-01 Bus Duct Cooling
		No	R13-02 Power Transmission
		No	R13-03 Metering & Relaying
R20	Plant A/C Electrical	Yes	R20-01 1E A/C Electrical Supply
		No	R20-02 Station Service A/C Electrical Supply
		No	R20-03 Grounding
R33	Conduits, Raceways & Trays	Yes	R33-01 Wire & Cable Integrity
		Yes	R33-02 Wire & Cable Integrity / Non-Safety Related

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
R42	D/C Electrical	Yes	R42-01 Plant 1E D/C Electrical Supply
		Yes	R42-02 EDG 1E D/C Electrical Supply
		No	R42-03 Cooling Tower D/C Supply
		No	R42-04 Switchyard D/C Supply
		Yes	R42-05 Diesel Fire Pump D/C Supply
		No	R42-06 24/48 D/C Supply
		Yes	R42-07 Appendix "R" Emergency Lights
R43	Emergency Diesel Generators	Yes	R43-01 Stand-by A/C Power Supply
R44	Uninterruptible Power Supply	No	R44-01 Vital A/C
R51	Plant Communications	Yes	R51-01 Personnel Communication
R52	Non Appendix "R" Emergency Lights	No	R52-01 Personnel Access/Egress
S11	Power Transformers	No	S11-01 Power Transmission
		Yes	S11-02 EDG 1B AC Supply
S30	Misc. Equip. & Welding Outlets	No	S30-01 Welding Support
S48	Switchyard Structures	No	S48-01 Power Transmission Equipment Integrity
T23	Primary Containment	Yes	T23-01 Torus/Drywell
T24	Fuel Storage	Yes	T24-01 Spent Fuel Integrity
		Yes	T24-02 New Fuel Integrity
T29	Reactor Building	Yes	T29-01 Containment and Support
T31	Cranes, Hoists & Elevators	No	T31-01 Equipment & Personnel Movement
		Yes	T31-02 Reactor Building Crane
T38	Tornado Vents	Yes	T38-01 Pressure Equalization

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
T41	Reactor Building HVAC	Yes	T41-01 Indirect Radioactive Release Control
		Yes	T41-02 Essential Mechanical/Environ. Support - ECCS Room Coolers
		No	T41-03 Reactor Building/Refueling Floor Environmental Control
		No	T41-04 Miscellaneous Exhaust Fans (Unit 1)
		No	T41-05 Reactor Building Area cooling
		No	T41-06 Temperature Monitoring
		Yes	T41-07 Essential Mechanical/Environ. Support - RCIC and CRD Room Coolers
T45	Equipment and Floor Drainage	No	T45-01 Waste Liquid Collection
		No	T45-02 Primary/Secondary Containment Abnormal Leakage Indication/Isolation
T46	Standby Gas Treatment	Yes	T46-01 Indirect Radioactive Release Control
T47	Drywell Cooling	No	T47-01 Drywell Mechanical/Environmental Support
		No	T47-02 Display of Event Information for Operator

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
T48	Primary Containment Purge & Inerting	Yes	T48-01 Primary Containment Nitrogen Inerting
		No	T48-02 Primary Containment Purge And Vent
		Yes	T48-03 Primary Containment Vacuum Relief
		Yes	T48-04 Containment/Reactor Building Parameter Monitoring
		No	T48-05 ILRT Connection Path
		Yes	T48-06 Drywell Pneumatic Nitrogen Supply
		No	T48-07 TIP System Nitrogen Supply
		No	T48-08 Turbine Building Nitrogen Blanketing Supply
		No	T48-09 Reactor Building Instrument Air Nitrogen Back-up
		No	T48-10 Hydrogen Recombiner Nitrogen Blanketing Supply
T49	Post LOCA Hydrogen Recombiners	Yes	T49-01 Containment Combustible Gas Control (Unit 2 Only)
T51	A/C Lighting	No	T51-01 Personnel Access and Safety
T52	Drywell Penetrations	Yes	T52-01 Primary Containment Integrity
T54	Reactor Building Penetrations	Yes	T54-01 Secondary Containment Integrity
U29	Turbine Building	Yes	U29-01 BOP Equipment Integrity and Support
U31	Cranes, Hoists & Elevators	No	U31-01 Turbine Building Crane[3]
U41	Turbine Building HVAC	No	U41-01 Turbine Building Ventilation
		No	U41-02 Turbine Building Cooling (Area Coolers)
U61	Turbine Building Leak Detection	No	U61-01 Turbine Building Temperature Monitoring
		No	U61-02 Electrical Signal Interlock
V29	Radwaste Building	No	V29-01 Waste Processing Equipment Integrity
V41	Radwaste Building HVAC	No	V41-01 Radwaste Building Environmental Control

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
W21	Circulating Water System Sump Pumps	No	W21-01 Circulating Water Pump Equipment Integrity[4]
W23	Circulating Water Chlorination	No	W23-01 Algae/Barnacle Growth Inhibitor (Unit 1 Only)
W24	Cooling Towers	No	W24-01 Heat Exchanger
W29	Circulating Water Structures	No	W29-01 Circulating Water System Integrity
W33	Traveling Water Screens/Trash Rakes	Yes No Yes	W33-01 Intake Structure Trash Removal W33-02 Screen Wash W33-03 Screen Wash Isolation
W35	Intake Structure	Yes	W35-01 RHRSW and PSW system Integrity
X29	Buildings	No	X29-01 Equipment Integrity & Personnel Habitability
X41	Outside Structure HVAC	Yes Yes Yes Yes Yes	X41-01 Intake Structure Environmental Control X41-02 EDG Building Environmental Control X41-03 EDG Building Battery Room H2 Control X41-04 EDG Switchgear Room Heating and Ventilation X41-05 EDG Building Oil Storage Room Ventilation

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
X42	Potable/Sanitary Water	No	X42-01 Drinking & Sanitary Water
X43	Fire Protection	Yes	X43-01 Cardox Fire Suppression for EDG's
		Yes	X43-02 Halon Fire Suppression for Remote Shutdown Panel (Unit 2)
		No	X43-03 RPV Inventory Makeup
		Yes	X43-04 Plant Wide Fire Suppression With Water
		No	X43-05 Halon Fire Suppression For Miscellaneous Applications
		Yes	X43-06 Fire Detection
		Yes	X43-07 Penseals & Fire Barriers For Preventing Fire Propagation
		Yes	X43-08 Manual CO_2 Fire Protection
		No	X43-09 EDG Building Fire Protection[5]
		Yes	X43-10 Cardox Fire Suppression for the Computer Room
X75	Emergency Response Facilities	Yes	X75-01 Class 1E Signal Isolation
		No	X75-02 Plant Parameter Monitoring (SPDS/ERFDS)
		No	X75-03 Emergency Response Coordination/Support
		No	X75-04 Plant Simulator
Y29	Yard Structures	Yes	Y29-01 Equipment Integrity and Personnel Habitability
Y32	Off-Gas Stack[6]	Yes	Y32-01 Gaseous Effluent Elevated Release
Y33	Meteorological Tower	No	Y33-01 Weather Monitoring
Y34	Security	No	Y34-01 Facility Protection
Y39	EDG Building	Yes	Y39-01 EDG and Equipment Integrity
Y42	Deep Well Pumps	No	Y42-01 Sanitary Water Supply
Y44	Sewage & Sanitary Drains	No	Y44-01 Sewage Treatment
Y47	Microwave	No	Y47-01 Intra Company Communication
Y52	Fuel Oil	Yes	Y52-01 EDG Fuel Oil Supply
		No	Y52-02 Auxiliary Boiler Fuel Oil Supply

Table 2.2-1 Plant Hatch System/Structure Function Scoping Results (Continued)

System Number	System Name	In Scope	Function Number/Name
Z29	Control Building	Yes	Z29-01 Equipment Integrity & Personnel Habitability
Z41	Control Building HVAC	No	Z41-01 LPCI Inverter Room Essential Cooling/Environmental Support[1]
		Yes	Z41-02 Control Room Habitability and Essential Mechanical/Environmental Support.
		Yes	Z41-03 Control Building Environmental Support
Z52	Chemical Lab	No	Z52-01 Perform Lab Tests

Notes:

1. Function no longer exists, but is retained in the listing solely for continuity.
2. F16-01 is retained for continuity purposes. The function is included in T24-02.
3. U31-01 is retained for continuity purposes. The function is included in T31-01.
4. W21-01 is retained for continuity purposes. The function is included in W29-01.
5. X43-09 is retained for continuity purposes. The function is included in X43-01.
6. The elevated release structure is commonly referred to in this application as the main stack.

2.3 MECHANICAL SYSTEMS SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions associated with the system;
- A list of the various mechanical component groups for the system that are subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.3.1 REACTOR

2.3.1.1 Reactor Assembly System [B11]

System Description

The reactor vessel has three major purposes:

- Contain core, internals and moderator.
- Serve as a high integrity barrier against leakage.
- Provide a floodable volume.

The reactor assembly consists of the reactor pressure vessel (RPV) and its internal components of the core, shroud, steam separator and dryer assemblies, and jet pumps. Also included in the reactor assembly are the control rods, control rod drive (CRD) housings, and the CRD. The RPV is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The major reactor internal components are the core (fuel, channels, control blades, and instrumentation), the core support structure (including the core shroud, shroud head, separators, top guide, and core support), the steam dryer assembly, and the jet pumps. The reactor internal structural elements are stainless steel or other corrosion-resistant alloys.

The reactor vessel is located inside the primary containment building. The internal environment of the RPV is reactor water, normally at 533 °F and 1055 psia during plant operation. Water quality is maintained within the specified limits. During plant conditions that require the operation of the shutdown cooling mode of RHR, reactor water can be cooled to approximately 117 °F via the RHR heat exchangers and recirculated back to the reactor through the residual recirculating system (RRS) piping. During plant shutdown conditions, the water temperature in the RPV can be as low as 70 °F.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

B11-01 – Nuclear Boiler. The reactor vessel internals provide proper coolant distribution to allow power operation without fuel damage and provide positioning and support for fuel assemblies to ensure control rod movement is not impaired. The RPV including the control rods and drives are evaluated as a pressure boundary as part of the nuclear boiler system [B21].

Although the pressure boundary function was scoped as part of function B21-02 in this application, the RPV and control rod drive pressure boundary components are listed in Table 2.3.1-1 for convenience of review.

B11-02 – Reactivity Control. The CRD housing supports mitigate damage to the fuel barrier in the event a drive housing breaks or separates from the bottom of the reactor.

Component Groups Requiring an Aging Management Review

Table 2.3.1-1 Components Supporting Reactor and Internals System [B11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Access Hole Covers*	Pressure Boundary	Nickel Based Alloy
Appurtenances	Pressure Boundary Fission Product Barrier Structural Support	Nickel Based Alloy Stainless Steel
Attachments and Connecting Welds	Pressure Boundary Fission Product Barrier Structural Support	Carbon Steel Low Alloy Steel Nickel Based Alloy Stainless Steel
Closure Studs	Pressure Boundary Fission Product Barrier	Low Alloy Steel
Control Rod Drive	Pressure Boundary Structural Support	Stainless Steel
Core ΔP/SLC Line*	Pressure Boundary	Stainless Steel
Core Spray Internal Piping	Pressure Boundary	Stainless Steel
Core Spray Sparger	Pressure Boundary Flow Distribution	Stainless Steel
Core Support Plate*	Pressure Boundary Structural Support	Stainless Steel
CRD Housing and CR Guide Tubes	Structural Support	Stainless Steel
Dry Tube Weld to Guide Tube	Pressure Boundary	Stainless Steel
Fuel Supports*	Pressure Boundary Structural Support	Cast Austenitic Stainless Steel
Jet Pump Assemblies	Pressure Boundary Structural Support	Stainless Steel Cast Austenitic Stainless Steel
Nozzles	Pressure Boundary Fission Product Barrier Structural Support	Low Alloy Steel
Penetrations	Pressure Boundary Fission Product Barrier Structural Support	Nickel Based Alloy Stainless Steel
Safe Ends	Pressure Boundary Fission Product Barrier Structural Support	Stainless Steel Carbon Steel Low Alloy Steel Nickel Based Alloy
Shell and Closure Heads	Pressure Boundary Fission Product Barrier Structural Support	Low Alloy Steel

Component Groups Requiring an Aging Management Review

Table 2.3.1-1 Components Supporting Reactor and Internals System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Material
Shroud	Pressure Boundary Structural Support	Stainless Steel
Shroud Supports	Pressure Boundary Structural Support	Nickel Based Alloy Low Alloy Steel
Shroud Tie Rods*	Structural Support	Stainless Steel
Thermal Sleeves	Pressure Boundary Fission Product Barrier	Stainless Steel Nickel Based Alloy
Top Guide	Structural Support	Stainless Steel

* No aging effects requiring management

2.3.1.2 Nuclear Boiler System [B21]

System Description

The nuclear boiler system is composed of several components and subsystems that are required to generate steam. Functions provided by the nuclear boiler system include supplying feedwater to the reactor, conducting steam from the reactor, reactor overpressure protection, and some reactor control and/or engineered safety feature functions. The nuclear boiler system is in operation any time the plant is in operation. Most of the major components in the system are part of the reactor coolant pressure boundary.

The system contains the following major components:

- Main steam lines (MSLs).
- Safety relief valves (SRVs).
- Main steam isolation valves (MSIVs).
- Feedwater lines.
- Feedwater line check valves.
- Instrumentation and controls.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

B21-01 – Pressure Control. The pressure control function of the nuclear boiler system prevents any overpressurization of the nuclear system. It also provides automatic depressurization for small breaks to allow for low pressure coolant injection (LPCI) and core spray (CS) operation. This function is described as the automatic depressurization system (ADS). The low-low set (LLS) function mitigates the thrust loads on the SRV discharge lines and the high-frequency loads on the torus shell from subsequent SRV actuations during small and intermediate-break loss of coolant accidents (LOCAs). The LLS also allows extended time between SRV subsequent actuations to allow the SRV discharge line water leg to return to original level after an actuation.

B21-02 – Reactor Coolant Pressure Boundary Integrity. The nuclear boiler system is designed to maintain the reactor coolant pressure boundary integrity. This function includes pressure containing Class 1 piping and components which form a portion of the reactor coolant pressure boundary with the exceptions of the pressure control and reactor recirculation functions.

For primary containment isolation devices, only the valve body is included in the scope of B21-02. The remainder of the valves (operators, motors, etc.) are included in system C61 (primary containment isolation). Portions of the following pressure containing systems are included in the B21-02 function: B11, B31, C11, C41, E11, E21, E41, E51, G31, L50. The main steam line flow restrictors are also included in this function.

<u>B21-03 – Rod Worth Minimizer.</u> The rod worth minimizer provides a means of enforcing procedural restrictions on preprogrammed control rod manipulations which are designed to limit rod worth to the values assumed in the plant accident analysis (design basis rod drop accident).

<u>B21-04 – Nuclear Boiler Instrumentation.</u> Nuclear boiler instrumentation provides process information to the operator and signals to other systems in the nuclear power plant.

Component Groups Requiring an Aging Management Review

Table 2.3.1-2 Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Crack Growth Monitor (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Flow Restrictor	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping (non-Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping (Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifice (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Thermowell (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (non-Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies (non-Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies (Class 1)	Pressure Boundary Fission Product Barrier	Cast Austenitic Stainless Steel

2.3.1.3 Fuel [J11]

System Description

Nuclear fuel is provided as a high integrity assembly of fissionable material which can be arranged in a critical array. The assembly must be capable of efficiently transferring the generated fission heat to the circulating coolant water, while maintaining structural integrity and keeping the fission products contained.

The external environment of the fuel is a cladding surrounded by water.

The fuel cladding experiences the complete range of reactor coolant pressure and temperatures.

Additional information may be found in Unit 2 FSAR paragraph 4.2.1.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in <u>Section 2.1.2</u>, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>J11-01 – Energy Source.</u> The nuclear fuel provides a high-integrity assembly of fissionable material capable of efficiently transferring the generated fission heat to the circulating reactor coolant water, while maintaining structural integrity and keeping the fission products contained. The nuclear fuel serves as the initial barrier to release of fission products. The fuel assembly is designed to ensure that fuel damage does not result in the release of radioactive materials in excess of the guideline values of 10 CFR 20.1- 20.601, 50 and 100.

<u>J11-02 – Spent Fuel Fission Product Barrier.</u> The spent fuel fission product barrier provides the barrier to prevent the release of fission products that are retained in the spent fuel. The Zircaloy-2 cladding that covers the spent fuel mitigates the consequences of a fuel handling accident. The cladding ensures that fuel damage does not result in the release of radioactive materials in excess of the guidelines values of 10 CFR 20.1- 20.601, 50 and 100.

Component Groups Requiring an Aging Management Review

None

2.3.2 REACTOR COOLANT SYSTEMS

2.3.2.1 Reactor Recirculation System [B31]

System Description

The reactor recirculation system (RRS) is one of two core reactivity control systems. The RRS system is part of the reactor coolant pressure boundary. Therefore, it also functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

RRS consists of two parallel loops, each consisting of a recirculation pump, suction and discharge block valves, piping, fittings, flow elements and connections supporting flow, and differential pressure instrumentation. The RRS interfaces with the residual heat removal (RHR) and reactor water cleanup (RWCU) systems to provide a flow-path in support of shutdown cooling, low pressure coolant injection (LPCI), RWCU, and reactor water level control functions.

More information about this system may be found in Unit 1 FSAR Section 4.3 and Unit 2 FSAR subsection 5.5.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

B31-02 – Recirculating Pump Trip Breaker Trip. The recirculating pump trip (RPT) breakers are designed to trip the reactor on appropriate signals—high reactor vessel steam dome pressure signal, or an indication of an ATWS-RPT reactor water level. The RPT breakers trip to prevent the core from exceeding thermal limits during abnormal transients. The system function is designed to aid the reactor protection system (RPS) in protecting the integrity of the fuel barrier. This function meets the safe shutdown criteria on the basis that the RPS is necessary to allow the control rods or the standby liquid control (SLC) system to safely and effectively shutdown the reactor.

B31-03 – Reactor Coolant Pressure Boundary. The RRS ensures adequate core cooling during power operation by supplying coolant flow past the reactor fuel bundles. The system consists of two loops external to the RPV. The piping, pumps, and valves that form these loops make up part of the reactor coolant pressure boundary.

This function only includes recirculation piping, pumps, and valves up to the first isolation valves of the small bore branches. Class 1 piping including valves B31-F019/20 will be evaluated as part of B21-02. Valves B31-F031 A/B are required for EQ compliance per the EQ master list.

Component Groups Requiring an Aging Management Review

Table 2.3.2-1 Components Supporting Reactor Recirculation [B31] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting (Class 1)	Fission Product Barrier, Pressure Boundary	Carbon Steel
Flow Nozzle (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Pump Casings and Cover (Class 1)	Fission Product Barrier, Pressure Boundary	Cast Austenitic Stainless Steel
Thermowell (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies (Class 1)	Fission Product Barrier, Pressure Boundary	Cast Austenitic Stainless Steel
Valve Bodies (Class 1)	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.3 ENGINEERED SAFETY FEATURES

2.3.3.1 Standby Liquid Control System [C41]

System Description

The standby liquid control system assures reactor shutdown, from full power operation to cold subcritical, by mixing a neutron absorber with the primary reactor coolant. The system is designed for the condition when an insufficient number of control rods can be inserted from the full power setting. The neutron absorber is injected within the core zone in sufficient quantity to provide a sufficient margin for leakage or imperfect mixing. The system is not a scram or a backup scram system for the reactor; it is an independent backup system for the control rod drive (CRD) system.

The standby liquid control system is located in the reactor building and consists of a low temperature sodium pentaborate solution storage tank, a test tank, a pair of full capacity positive displacement pumps, two explosive actuated shear plug valves, two accumulators, the poison sparger, and the necessary piping, valves, and instrumentation. The standby liquid control system is manually initiated from the control room by use of a three-position key-lock switch.

More information can be found on this system in Unit 2 FSAR subsection 4.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C41-01 – Reactivity Control. The standby liquid control system assures reactor shutdown from full power operation to cold subcritical by mixing a neutron absorber with the primary reactor coolant.

C41-03 – SLC Testing. The testing function is not safety related. However, to accomplish this function, equipment from the C41-01 function is used as well as the test tank and piping. The equipment common to C41-01 is brought in scope under that function. The test tank is qualified to seismic category II/I criteria and, therefore, has the potential to prevent a safety-related function. It is for that reason that this function is conservatively brought into scope.

Component Groups Requiring an Aging Management Review

Table 2.3.3-1 Components Supporting Standby Liquid Control [C41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Stainless Steel
Pump Accumulators	Pressure Boundary	Carbon Steel
Pump Casings	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Stainless Steel
Temperature Element	Pressure Boundary	Stainless Steel
Temperature Switch	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.3.2 Residual Heat Removal System [E11]

System Description

The residual heat removal (RHR) system is composed of several components and subsystems which are required to:

- Restore and maintain reactor vessel water level after a loss of coolant accident (LOCA);
- Limit temperature and pressure inside the containment after a LOCA;
- Remove heat from the suppression pool water; and
- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

Note that the RHR service water functions are included in E11.

The RHR system consists of four pumps and two heat exchangers divided into two loops of two pumps and one heat exchanger each, plus the associated instruments, valves, and piping. The RHR pumps take suction from the suppression pool or the reactor coolant recirculation loop. The pumps discharge into the recirculation loop, the suppression pool, the containment spray headers, the spent-fuel pool cooling and cleanup system, depending upon the desired mode of system operation. The RHR system interfaces with the recirculation system to provide a flow-path in support of shutdown cooling and low pressure coolant injection (LPCI). The RHR system is part of the reactor coolant pressure boundary; therefore, it also maintains the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

The RHR system is cooled through the heat exchangers by the residual heat removal service water (RHRSW) system. The RHRSW takes suction from the Altamaha River. There are four RHRSW pumps per unit. The RHRSW system also serves as a standby coolant supply system by providing a means of injecting makeup water from the river to the RHR system to keep the core covered during an extreme emergency.

More information about the RHR system may be found in Unit 1 FSAR Section 4.8 and Unit 2 FSAR subsection 5.5.7.

The above system description is general information provided as an aid in the review of this license renewal application. As described in <u>Section 2.1.2</u>, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

<u>E11-01 – Low pressure Coolant Injection (LPCI).</u> The LPCI restores and maintains the coolant inventory in the reactor vessel so the core is adequately cooled following a design basis LOCA and other design basis events.

E11-02 – Containment Spray. Containment spray provides post-accident containment atmosphere temperature and pressure control by use of spray nozzles located in both the drywell and the torus area.

E11-04 – RHRSW Vessel/Containment Injection. RHRSW provides a reliable supply of cooling water to the reactor pressure vessel (RPV) following a loss of RHR/core spray or to flood the primary containment to provide cooling to the exterior of the reactor vessel using raw river water.

E11-05 – Shutdown Cooling. Shutdown cooling removes decay and residual heat from the reactor during shutdown and cooldown when the reactor pressure is so low that the vacuum in the condenser cannot be maintained, rendering the condenser inoperable or the high pressure coolant injection (HPCI) and/or reactor core isolation cooling (RCIC) pumps inoperable due to a lack of steam.

E11-08 – Suppression Pool Cooling. Suppression pool cooling limits the water temperature in the suppression pool to ensure it has adequate heat capacity remaining in the event of a design basis LOCA, and removes heat post-accident and during testing of the HPCI and RCIC systems.

E11-10 – Alternate Shutdown Cooling. Alternate shutdown cooling provides an alternate means to cool and depressurize the reactor vessel following a fire or other transient which leads to a loss of shutdown cooling.

Component Groups Requiring an Aging Management Review

Table 2.3.3-2 Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Conductivity Element	Fission Product Barrier, Pressure Boundary	Stainless Steel
Heat Exchanger Channel Assembly	Pressure Boundary	Carbon Steel
Heat Exchanger Impingement Plate	Shelter/ Protection	Stainless Steel
Heat Exchanger- Shell	Fission Product Barrier, Pressure Boundary	Carbon Steel
Heat Exchanger Tube Sheet	Fission Product Barrier Pressure Boundary	Carbon Steel Stainless Steel
Heat Exchanger Tubes	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings - Bowl Assembly	Pressure Boundary	Cast Austenitic Stainless Steel
Pump Discharge Head	Pressure Boundary	Carbon Steel
Pump Sub Base	Structural Support	Carbon Steel
Restricting Orifices	Fission Product Barrier, Pressure Boundary, Flow Restriction	Stainless Steel
Strainer Bodies	Debris Protection	Carbon Steel
Strainers	Debris Protection	Stainless Steel
Thermowell	Fission Product Barrier, Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Carbon Steel

2.3.3.3 Core Spray System [E21]

System Description

The core spray (CS) system is one of the emergency core cooling systems (ECCSs) which protects the core from overheating in the event of a loss of coolant accident (LOCA). The CS system is a low pressure system. Actuation of the CS system results from low reactor vessel water level (level 1) or high drywell pressure or manual action. Injection valves to the reactor require a signal from the reactor low pressure permissive switches before opening to provide over-pressure protection to the system. The pumps take suction from the suppression pool and spray on the top of fuel assemblies to cool the core and limit the fuel cladding temperature. An alternate suction source for the CS system, the condensate storage tank (CST), is used primarily for providing reactor pressure vessel (RPV) makeup and an injection test supply during outages, and would not normally be used post accident. The CS system works in conjunction with low pressure coolant injection (LPCI).

The CS system has two independent loops. Each loop includes a 100% capacity centrifugal pump driven by an electric motor, a sparger ring in the reactor vessel above the core, piping, valves, and associated controls and instrumentation. To enable the CS system to make a quick startup and to minimize the water hammer possibilities during startup, the CS system discharge lines are always maintained full of water by the jockey pump system. The jockey pump system consists of two centrifugal pumps in each of the two loops. The suction and discharge lines of these pumps are connected through piping and valves to the suction and discharge lines of the CS pumps respectively. Continuous operation of the jockey pumps ensures the ECCS's discharge lines remain full. The jockey pump system also provides the same feature for the residual heat removal (RHR) system.

The CS system is described in Unit 1 FSAR subsection 6.4.3 and Unit 2 FSAR paragraph 6.3.2.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E21-01 – Core Cooling. The CS system protects the core by removing decay heat following a postulated design basis LOCA or other design basis event.

E21-04 – Alternate Shutdown Cooling. The CS system provides an alternate means to cool and depressurize the reactor vessel following a fire.

E21-05 – Emergency Core Cooling System Keep Fill. The jockey pumps of the Core Spray System are provided to keep the core spray and low pressure coolant injection lines full of water, thus minimizing the delay time for emergency core cooling and the possibility of water hammer. This function is brought into scope solely as a pressure boundary.

Component Groups Requiring an Aging Management Review

Table 2.3.3-3 Components Supporting Core Spray System [E21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Pump Casings	Fission Product Barrier, Pressure Boundary	Carbon Steel
Restricting Orifice	Fission Product Barrier, Pressure Boundary, Flow Restriction	Stainless Steel
Strainers	Debris Protection	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel

2.3.3.4 High Pressure Coolant Injection System [E41]

System Description

The high pressure coolant injection (HPCI) system supplies makeup coolant into the reactor vessel from a fully pressurized to a preset depressurized condition. Demineralized makeup water is supplied from the condensate storage tank (CST) or treated water from the suppression pool. The flow rate of the system will maintain the reactor vessel coolant inventory until the reactor pressure drops sufficiently to permit the low pressure core cooling systems to automatically inject coolant into the vessel.

The HPCI system consists of a turbine driven pump train, piping, valves, and controls that provide a complete and independent emergency core cooling system (ECCS). A test line permits functional testing of the system during normal plant operation. A minimum flow bypass line bypasses pump discharge flow to the suppression pool to protect the pump in the event of a stoppage in the main discharge line. Reactor vessel steam is supplied to the turbine. Turbine exhaust steam is then dumped to the suppression pool.

The HPCI system is further described in the Unit 1 FSAR subsection 6.4.1 and Unit 2 FSAR paragraph 6.3.2.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E41-01 – Core Cooling. The HPCI system assures the reactor is adequately cooled to limit fuel-clad temperature in the event of a small break in the reactor coolant system and a loss of coolant which does not result in rapid depressurization of the reactor vessel. This function permits shutdown of the plant while maintaining sufficient reactor vessel water inventory until the reactor is depressurized.

Component Groups Requiring an Aging Management Review

Table 2.3.3-4 Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Bolting	Pressure Boundary Fission Product Barrier	Stainless Steel
Flexible Connectors	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Pump Baseplate	Structural Support	Carbon Steel
Pump Casings	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifice	Pressure Boundary Flow Restriction Fission Product Barrier	Stainless Steel
Suction Strainer	Debris Protection	Stainless Steel
Thermowell	Pressure Boundary	Stainless Steel
Turbine	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.3.5 Reactor Core Isolation Cooling System (RCIC) [E51]

System Description

The reactor core isolation cooling (RCIC) system is a high pressure coolant makeup system which supports reactor shutdown when the feedwater system is unavailable. The RCIC system provides the capability of maintaining the reactor in a hot standby condition for an extended period. Normally, however, the RCIC system is used until the reactor pressure is sufficiently reduced to permit use of the shutdown cooling mode of the residual heat removal (RHR) system.

The RCIC system consists of a turbine driven pump, piping and valves, and, the instrumentation necessary to maintain the water level in the reactor vessel above the top of the active fuel should the reactor vessel be isolated from normal feedwater flow. Also included in the design of the RCIC system is a barometric condenser, and vacuum and condensate pumps to prevent steam from leaking into the environment.

The system is described in the Unit 1 FSAR, Section 4.7 and Unit 2 FSAR subsection 5.5.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

E51-01 – Core Cooling. The RCIC system provides a high pressure makeup coolant system which supports the reactor shutdown when the feedwater system is unavailable.

Component Groups Requiring an Aging Management Review

Table 2.3.3-5 Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Bolting	Pressure Boundary Fission Product Barrier	Stainless Steel
Flexible Connector	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Pump Baseplate	Structural Support	Carbon Steel
Pump Casing	Pressure Boundary Fission Product Barrier	Carbon Steel
Restricting Orifices	Pressure Boundary, Flow Restriction Fission Product Barrier	Stainless Steel
Steam Trap	Pressure Boundary Fission Product Barrier	Stainless Steel
Steam Trap	Pressure Boundary Fission Product Barrier	Carbon Steel
Strainer- Steam Exhaust	Pressure Boundary Fission Product Barrier	Carbon Steel
Suction Strainer	Debris Protection	Stainless Steel
Thermowell	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell	Pressure Boundary Fission Product Barrier	Stainless Steel
Turbine	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Cast Austenitic Stainless Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.3.6 Standby Gas Treatment System [T46]

System Description

The standby gas treatment system (SGTS) is an engineered safety feature (ESF) system for ventilation and cleanup of the primary and secondary containment during certain postulated design basis accidents (DBAs), and meets the design, quality assurance, redundancy, energy source, and instrumentation requirements for ESF systems. The SGTS is also used as a normal means of venting the drywell.

The major components of the SGTS include redundant filter trains, control valves, backdraft dampers, fans, and control instrumentation. Each of the filtration assemblies and their respective components are designed for 100-percent-capacity operation.

Additional information may be found for this system in Unit 1 FSAR paragraph 5.3.3.3 and Unit 2 FSAR subsection 6.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T46-01 – Indirect Radioactive Release Control. The SGTS is designed to minimize the release of radioactive materials to the environment during accident conditions. The SGTS is the ESF system for ventilation and cleanup of the primary and secondary containment during certain postulated DBAs.

Component Groups Requiring an Aging Management Review

Table 2.3.3-6 Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Filter Housing	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Piping	Fission Product Barrier, Pressure Boundary	Copper
Piping	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Rupture Disc	Fission Product Barrier, Pressure Boundary	Stainless Steel
Thermowell	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Gray Cast Iron
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Copper Alloy

2.3.3.7 Primary Containment Purge And Inerting System [T48]

System Description

The primary containment purge and inerting system primarily provides and maintains an inert atmosphere in the primary containment for combustible gas control and fire protection. Plant Technical Specifications require that within 24 hours of reactor operation, the inerting system injects a sufficient amount of gaseous nitrogen into the drywell and torus so that the oxygen concentration falls below 4% by volume.

Major equipment for the purge and inerting system includes a purge air supply fan, liquid nitrogen storage tank, ambient vaporizer, steam vaporizer, vacuum breaker, valves, piping, controls, and instrumentation. The purge and inerting system provides containment vent paths to the standby gas treatment system which provides a vent path to the main stack for containment vent and purge operations.

More information may be found in Unit 1 FSAR paragraph 5.2.3.8 and 9 and Unit 2 FSAR Section 6.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T48-01 – Primary Containment Nitrogen Inerting. The purge and inerting system provides and maintains an inerted atmosphere in the primary containment for combustible gas control and fire protection purposes.

T48-03 – Primary Containment Vacuum Relief. The primary containment relief valves are designed to maintain an external pressure of not more than 2 psi greater than the concurrent internal pressure. It is to prevent a collapse in either the drywell or torus as a result of the most rapid cooldown transient that can occur during operation or a postulated accident condition assuming the failure of a single active component.

T48-04 – Containment/ Reactor Building Parameter Monitoring. The containment/reactor building parameter monitoring function monitors and records drywell and torus safety parameters in the main control room. The parameters monitored include torus air and water temperature, water level, pressure and drywell pressure and temperature.

T48-06 – Drywell Pneumatic Nitrogen Supply. The purge and inerting system provides a safety grade back-up supply of nitrogen gas for the drywell pneumatic system. The nitrogen gas provides motive force to the nuclear boiler system safety relief valves, main steam isolation valves, and various other safety-related valves in the event of a loss of normal drywell pneumatic supply.

Component Groups Requiring an Aging Management Review

Table 2.3.3-7 Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Flex Hose	Pressure Boundary Fission Product Barrier	Stainless Steel
Nitrogen Tank Jacket	Structural Support	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pressure Buildup Coil	Pressure Boundary Exchange Heat	Stainless Steel
Rupture Disc	Pressure Boundary	Stainless Steel
Storage Tank	Pressure Boundary	Stainless Steel
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel
Vaporizer	Pressure Boundary Exchange Heat	Stainless Steel

2.3.3.8 Post LOCA Hydrogen Recombiners System [T49] (Unit 2 only)

System Description

The post loss of coolant accident (LOCA) hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA. This is accomplished by drawing primary containment atmosphere from the drywell and passing it through the recombiner where the hydrogen reacts with available oxygen to form water vapor. The recombiner discharge is to the suppression pool (torus).

The hydrogen recombiner system is part of the combustible gas control system and consists of two independent 100% capacity identical trains. Each train consists of three packages: the recombiner skid, the control console, and the power panel. The recombiner skid consists of inlet piping, flowmeters, flow control valve, an enclosed blower assembly, heater section, reaction chamber, direct contact water spray connected to the power panel, and the control console through instrument and power cables. Coolant for the water spray gas cooler is provided by the residual heat removal (RHR) system.

More information can be found about this system in Unit 2 FSAR subsection 6.2.5.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T49-01 – Containment Combustible Gas Control. The post LOCA hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA.

Component Groups Requiring an Aging Management Review

Table 2.3.3-8 Components Supporting Post LOCA Hydrogen Recombiner System [T49] Intended Functions and Their Component Functions (Unit 2 only)

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Carbon Steel
Valve Bodies	Pressure Boundary Fission Product Barrier	Stainless Steel

2.3.4 AUXILIARY

2.3.4.1 Control Rod Drive (CRD) System [C11]

System Description

The CRD hydraulic system provides pressurized, demineralized water for the cooling and manipulation of the CRD mechanisms. In addition, the CRD system provides purge water for the reactor water cleanup (RWCU) pump and reactor recirculation pump seals.

The alternate rod insertion system is a subsystem of the CRD system. It is a backup means of scramming the reactor by venting the scram air header. It is completely independent of the reactor protection system (RPS) and was installed for the purpose of reducing the probability of an anticipated transient without scram (ATWS) event.

Water enters the CRD system from the condensate header downstream of the condensate demineralizers (normal suction) or from the condensate storage tank (CST) (alternate suction). The condensate header is the preferred suction source because the water contains less oxygen (deaerated) than water from the CST.

More information about this system may be found in Unit 2 FSAR subsections 4.1.3 and 4.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C11-04 – Reactor Scram. The scram mode allows quick shutdown of the reactor by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal.

C11-07 – Alternate Rod Insertion. Alternate rod insertion reduces the probability of the occurrence of an scram event. Signals are provided which respond to an ATWS event or to a manual initiation to depressurize the CRD scram pilot valve air header using valves that are different from the RPS scram valves, thus providing a parallel path for control rod insertion.

Component Groups Requiring an Aging Management Review

Table 2.3.4-1 Components Supporting Control Rod Drive System [C11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Accumulator	Fission Product Barrier, Pressure Boundary	Carbon Steel
Bolting	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Carbon Steel
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Rupture Disc	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Carbon Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Copper Alloy
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.4.2 Refueling Equipment System [F15]

System Description

The refueling platform equipment assembly is used for handling and transporting reactor core internals and service and handling equipment associated with the refueling operation. The refueling platform equipment assembly consists of the refueling platform, fuel grapple, grapple headlight, and the hardware required to assemble these components into a workable unit.

The refueling platform is a bridge structure that spans the refueling pool and the reactor well and travels on rails which extend the length of the fuel storage pool and the reactor well. A working platform extends the width of the bridge structure, providing working access to the entire width of the pools and reactor well area. The combination of the bridge movement for the length of the pool and the trolley movement for the width of the pool provides complete access to the open pool and reactor well. The movements of the bridge and trolley are displayed so that positions above known locations, such as the location of in-core fuel assemblies, can be repeatedly reproduced from dials on the trolley cab.

The fuel grapple extends downward, below the underside of the refueling platform, into the pool or reactor well. The telescoping grapple is extended or lowered by a fuel hoist. The position of the air-operated grapple is indicated in the control station.

More information on refueling may be found in Unit 1 FSAR Section 7.6 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

F15-01 – Fuel/Control Rod Handling. The fuel/control rod handling function supports fuel movement and control rod change out and includes the refueling bridge, grapple, hoists, spent fuel servicing equipment, tools, and refueling interlocks.

The structural integrity of the refueling platform is the passive portion of the assembly that is within scope of the License Renewal.

Component Groups Requiring an Aging Management Review

Table 2.3.4-2 Components Supporting Refueling Platform Equipment Assembly [F15] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Anchors and Bolts	Structural Support Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support Nonsafety Related Structural Support	Carbon Steel
Rivets*	Structural Support	Aluminum
Structural Steel	Structural Support	Carbon Steel

* No aging effects requiring management

2.3.4.3 Insulation System [L36]

System Description

The purpose of insulation is to help retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage.

Insulation is required in conjunction with heat tracing. Insulation is also credited in heat load calculations for safety related rooms. Failure of this insulation could allow the heat load of the room to exceed the capability of the HVAC system, thus exceeding the design temperature of the room.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L36-02 – Piping Insulation – Outside Drywell. Insulation is provided in various locations outside the drywell to help retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage. Examples of inscope piping systems that are heat traced with insulation are plant service water and fire protection. Insulation is also credited in heat load calculations for safety-related rooms. Heat tracing with insulation is required for the standby liquid control system to operate in order to meet ATWS requirements.

Component Groups Requiring an Aging Management Review

Table 2.3.4-3 Components Supporting Insulation [L36] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Aluminum Jacket	Environmental Control	Aluminum
Insulation	Environmental Control	Asbestos Ceramic Calcium Silicate Fiberglass Mineral Fiber
Insulation Bolting	Environmental Control	Galvanized Steel
Insulation Bolting	Environmental Control	Stainless Steel
Stainless Steel Jacket	Environmental Control	Stainless Steel
Wire for Insulation	Environmental Control	Carbon Steel

2.3.4.4 Access Doors System [L48]

System Description

The purpose of the secondary containment access doors is to provide access for personnel and equipment. The secondary containment provides, in conjunction with the primary containment and other engineering safeguards, the capability to limit the release to the environs of radioactive materials so that offsite dose from a postulated design basis accident will be below the guideline values of 10 CFR 100.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L48-01 – Containment Integrity. Only the doors necessary to maintain secondary containment are included in this function. Secondary containment plays a role in preventing offsite releases. Secondary containment doors have a passive function to maintain structural integrity to preserve secondary containment.

Component Groups Requiring Aging Management Review

Table 2.3.4-4 Components Supporting Access Doors [L48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Structural Steel	Missile Barrier Fission Product Barrier	Carbon Steel

2.3.4.5 Condensate Transfer & Storage System [P11]

System Description

The condensate transfer and storage system provides the plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type services. The total stored design quantity is based on the demand requirements during refueling for filling the dryer separator pool and the reactor well.

A 500,000 gallon condensate storage tank (CST) supplies the various unit requirements. The unit 1 tank is constructed of aluminum and the unit 2 tank of stainless steel. The system also consists of two condensate transfer pumps and associated piping and valves. The CST provides the preferred supply to the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. All other suctions are located above suction lines for these systems to provide a 100,000 gallon reserve.

The condensate transfer and storage system is described in Unit 1 FSAR Section 11.9 and Unit 2 FSAR subsection 9.2.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P11-01 – ECCS/CRD Condensate Supply. While the CST is nonsafety related, the preferred water source for the RCIC and HPCI systems is the CST. The design of the tank ensures 100,000 gallons of water are set aside for this supply. The HPCI and RCIC systems rely upon this volume of water during the response to station blackout.

Component Groups Requiring an Aging Management Review

Table 2.3.4-5 Components Supporting Condensate Transfer and Storage System [P11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Aluminum
Tanks	Pressure Boundary	Galvanized Steel
Tanks	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Cast Austenitic Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.6 Sampling System [P33]

System Description

The purpose of the primary containment hydrogen and oxygen analyzing system is to provide a means of monitoring hydrogen and oxygen in the primary containment (drywell and torus).

The primary containment hydrogen and oxygen analyzing system consists of two separate, redundant systems, each capable of analyzing the hydrogen and oxygen content from the drywell or torus. Each analyzer channel is operated in parallel from separate penetrations in the drywell and torus. The sample is drawn through a sample cooler by the sample system inlet pump, then pumped to the hydrogen and oxygen analyzer cells. The sample is then returned to the primary containment by the sample system outlet pump.

Additional information may be found in Unit 2 FSAR paragraph 6.2.4.3.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P33-01 – Display of Hydrogen/Oxygen Information. The hydrogen-oxygen analyzer system continually measures the hydrogen and oxygen concentrations in the primary containment atmosphere following a loss of coolant accident (LOCA). This information is recorded in the main control room (MCR), and hydrogen concentrations in the drywell above a predetermined level are annunciated. The system is treated as safety related due to Regulatory Guide 1.97 requirements and is included in the EQ program.

Component Groups Requiring an Aging Management Review

Table 2.3.4-6 Components Supporting Sampling System [P33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Piping	Fission Product Barrier, Pressure Boundary	Stainless Steel
Valve Bodies	Fission Product Barrier, Pressure Boundary	Stainless Steel

2.3.4.7 Plant Service Water System [P41]

System Description

The plant service water (PSW) system removes the heat generated by the operation of various systems (both safety related and nonsafety related). The PSW also provides makeup water to the plant circulating water system by supplying screened Altamaha river water to system heat exchangers. After traveling through the heat exchangers, the water is routed to the circulating water flume for use as flume makeup. The heat picked up by the water is rejected to the atmosphere via the plant cooling towers or to the river via the circulating water flume overflow. The PSW system water is also available for fire-fighting, radwaste dilution, and emergency spent fuel pool makeup.

The PSW system consists of four main pumps divided into two divisions of two pumps each. Each of the two divisions supplies one redundant train of safety-related equipment. After passing through isolation valves, the two safety-related headers merge into one header supplying nonsafety-related equipment. After servicing the various systems, the service water is discharged to a potential radioactive contaminant release path, and the discharge header is constantly monitored for activity.

The PSW system is described in the Unit 1 FSAR Section 10.7 and Unit 2 FSAR subsection 9.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P41-01 – Essential Mechanical/ Environmental Support. The PSW system removes heat generated by various safety-related plant systems, including the reactor building, emergency diesel generators (EDGs), control building, and refueling floor PSW supply.

P41-02 – Turbine Building Isolation. This function closes the 1P41-F310 and 2P41-F316 valves to isolate non-essential loads during emergency conditions to ensure adequate cooling to the diesels and other safety-related loads. This function includes only the isolation valves and associated equipment.

P41-05 – 1B Emergency Diesel Generator Cooling. Diesel Generator 1B is normally supplied by standby plant service water pump 2P41-C002, but during an emergency, generator 1B can be supplied from Unit 1 service water.

Component Groups Requiring an Aging Management Review

Table 2.3.4-7 Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Flexible Connector	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pump Bowl Assembly	Pressure Boundary	Cast Austenitic Stainless Steel
Pump Discharge Column	Pressure Boundary	Carbon Steel
Pump Discharge Head	Pressure Boundary	Carbon Steel
Pump Sub Base	Structural Support	Carbon Steel
Restricting Orifices	Pressure Boundary Flow Restriction	Stainless Steel
Sight Glass Body	Pressure Boundary	Carbon Steel
Sight Glass Body	Pressure Boundary	Stainless Steel
Sight Glasses*	Pressure Boundary	Ceramic
Strainer	Pressure Boundary	Carbon Steel
Strainer	Pressure Boundary	Gray Cast Iron
Strainer Basket	Debris Protection	Gray Cast iron
Strainer Basket	Debris Protection	Stainless Steel
Thermowells	Pressure Boundary	Carbon Steel
Thermowells	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel
Venturi	Pressure Boundary	Carbon Steel

* No aging effects requiring management

2.3.4.8 Reactor Building Closed Cooling Water System [P42]

System Description

The purpose of the reactor building closed cooling water (RBCCW) system is to provide cooling water to certain auxiliary equipment located in the reactor building.

The RBCCW system is a closed-loop cooling system consisting of three one-half capacity pumps, two full-capacity heat exchangers, a surge tank, and a chemical addition system. The cooling water is conveyed by the pumps to the various system coolers and returned to the pumps by way of the RBCCW heat exchanger. Two of the RBCCW pumps are normally operating with the third pump on standby. The system is started manually. The standby pump, when needed, starts automatically. The heat rejected by the RBCCW system to the heat exchanger is removed by the plant service water (PSW) system.

The RBCCW system is described in the Unit 1 FSAR Section 10.5 and Unit 2 FSAR subsection 9.2.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P42-01 – Reactor Building Equipment Cooling. The RBCCW system cools auxiliary plant equipment located in the reactor building and serves as a closed-cycle barrier between potentially radioactive systems and the plant service water systems. The RBCCW also utilizes demineralized water to substantially reduce the erosion and corrosion of the cooled components.

The RBCCW system is only in the scope of License Renewal to the extent that it provides containment integrity. Specifically, the inscope components function to maintain primary containment via a closed loop inside containment.

Component Groups Requiring an Aging Management Review

Table 2.3.4-8 Components Supporting Reactor Building Closed Cooling Water System [P42] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Flexible Connectors	Pressure Boundary	Stainless Steel
Flow Element	Pressure Boundary	Stainless Steel
Heat Exchanger Shells	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Copper Alloy
Piping	Pressure Boundary	Stainless Steel
Relief Valve Base	Pressure Boundary	Copper Alloy
Temperature Probe	Pressure Boundary	Copper Alloy
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.9 Instrument Air System [P52]

System Description

The purpose of the instrument air system is to provide dried and filtered air to all of the air operated instruments and valves throughout the entire plant (with the exception of equipment inside the drywell).

The instrument air system is divided into the following two subsystems:

- Noninterruptible system provides instrument air for the operation of certain emergency system components.
- Interruptible system provides instrument air to all other components not supplied by the noninterruptible system.

The drywell pneumatic system supplies the motive gas for components within the drywell.

The requirements for the remainder of the compressed air systems are supplied by three oil-free screw-type compressors. Two of these air compressors have a capacity of 500 std ft^3/min and one has a capacity of 700 std ft^3/min. During normal operation, the 700 std ft^3/min compressor supplies all instrument air and high pressure service air requirements outside of the drywell with one of the two 500 std ft^3/min compressors on automatic standby and the other (which requires operator action for start) in the backup mode. Each compressor discharges into an air receiver which in turn discharges into a common manifold that feeds the instrument and service air systems.

Additional information may be found in Unit 1 FSAR Section 10.11 and Unit 2 FSAR subsection 9.3.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P52-01 – Noninterruptible Essential Instrument Air Supply. The noninterruptible essential instrument air supply includes the instrument air system downstream of the noninterruptible essential instrument air check valves and includes the nitrogen backup supply valves. The P52 system is fed from the P51 air compressors under normal operating conditions and has a nonredundant backup of the safety-related nitrogen distribution system. The noninterruptible portion of the instrument air system services certain valves in emergency systems for which operation is desirable, though not essential, following loss of pressure in the service air or interruptible portion of the instrument air system.

Component Groups Requiring an Aging Management Review

Table 2.3.4-9 Components Supporting Instrument Air System [P52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Air Receiver	Pressure Boundary	Stainless Steel
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Hose	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Regulator-Pressure	Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Copper Alloy

2.3.4.10 Primary Containment Chilled Water System [P64] (Unit 2 Only)

System Description

The primary containment chilled water system is designed to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operation by providing chilled water to the drywell fan coil units. The primary containment chilled water system consists of two chilled water recirculation pumps, two centrifugal chillers, a chemical addition tank, a chemical feed pump, and an expansion tank. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water recirculation pump circulates chilled water through the respective chiller to the fan coil units. Service water from the reactor building service water system is circulated through the chiller condensers for cooling. Demineralized water provides a source of makeup water for the chilled water system. The expansion tank, chemical addition tank, and associated makeup water supply are shared with the reactor and radwaste building chilled water system.

More information may be found in Unit 2 FSAR subsection 9.4.6.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P64-02 – Drywell Cooling. This function is designed to support the drywell cooling system in an effort to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operations.

The only safety-related function provided during this mode is containment integrity. Specifically, the inscope components function to maintain primary containment integrity via a closed loop inside containment. The controls and instrumentation associated with primary containment isolation for this system function are evaluated as part of C61.

Component Groups Requiring an Aging Management Review

Table 2.3.4-10 Components Supporting Primary Containment Chilled Water System [P64] Intended Functions and Their Component Functions (Unit 2 Only)

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Cap	Pressure Boundary	Copper Alloy
Piping	Pressure Boundary	Carbon Steel
Thermowell	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel

2.3.4.11 Drywell Pneumatics System [P70]

System Description

The drywell pneumatic system supplies motive gas to the following equipment inside the drywell: reactor recirculation system sample line isolation valve, reactor pressure vessel (RPV) head vent valve, core spray (CS) system injection testable check valves and bypass valves, primary containment chilled water system control valves, residual heat removal (RHR) system low pressure coolant injection (LPCI) check valves and bypass valves, and nuclear boiler system safety relief valves (SRVs), and main steam isolation valves (MSIVs).

A major portion of the drywell pneumatic system is primarily obsolete and not currently used. The control air is supplied from the nitrogen makeup system or instrument air. The system components still exist in the plant but are isolated by valve alignment or the lines are physically cut and capped.

The drywell pneumatic system receives motive gas from the Unit 1 or Unit 2 nitrogen storage tanks, the instrument air system, or the emergency nitrogen hookup stations. The system includes an air receiver, particulate filters, flow sensing elements, and various process piping, valves, and regulators.

Normally all system equipment upstream of the receiver tank is isolated, and system pressure is maintained by the nitrogen back-up supply with alternate supply through the instrument air supply system. Under emergency condition specific components in the drywell will be supplied control air from emergency nitrogen bottles.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

P70-01 – Nitrogen Supply to Drywell Equipment. The nitrogen supply to the drywell equipment provides the motive gas to various equipment. The nitrogen inerting system (T48) supplies the motive gas to the drywell equipment in the drywell during normal operation. After an accident, the motive gas to drywell equipment can be provided from either the drywell pneumatic nuclear boiler system (B21) accumulator, the nitrogen inerting system, or one of the two nitrogen hookup stations.

Component Groups Requiring an Aging Management Review

Table 2.3.4-11 Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Filter Housings	Pressure Boundary	Carbon Steel
Filter Housings	Pressure Boundary	Stainless Steel
Flanges	Pressure Boundary	Carbon Steel
Flexible Hoses	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.12 Emergency Diesel Generators System [R43]

System Description

The purpose of the diesel generators is to provide emergency backup power to 4160 VAC emergency buses E, F, and G in the event of a loss of loss of offsite power. The diesel generators are designed to reach rated speed and voltage within 12 seconds after receiving a start signal. This allows operation of emergency equipment powered from these buses to perform their required function to safely shutdown the plant within the required time.

The emergency diesel generator (EDG) provides a highly reliable source of standby, onsite, ac power. There are five diesel generators supplying standby power to 4.16 kV essential buses: 1E, 1F, 1G of Unit 1; and 2E, 2F, and 2G of Unit 2. Diesel generators 2A and 2C supply buses 2E and 2G respectively. Diesel generator 1B is shared between Units 1 and 2 and can supply power to either 1F or 2F. Diesel generator 1B has a selector switch with "Unit 1 control" and "Unit 2 control" positions, depending on whether it is supplying bus 1F or 2F. Diesel generators 1A and 1C supply buses 1E and 1G, respectively.

The generator field is supplied dc power by a static exciter. The exciter-regulator provides a controlled current to the generator field winding to maintain and control the generator output voltage.

In the automatic mode of voltage control, the generator output voltage is compared to a reference voltage to produce an error signal. Current transformers measure generator load and produce a proportional output. The load signal and voltage error signal are vectorally summed to produce an output which determines the generator field current and, thereby, the generator output voltage.

In the manual mode, the operator controls generator output voltage by adjusting the voltage control lever on the remote control panel. When the voltage balance relay is energized, the output voltage control is transferred from automatic to manual.

Additional information may be found in Unit 1 FSAR Section 8.4 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R43-01 – Standby AC Power Supply. The standby ac power supply provides ac power in the event of a loss of offsite power. The emergency diesel generator load sequencers are included in this function.

Component Groups Requiring an Aging Management Review

Table 2.3.4-12 Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions

Component	Component Functions	Material
Expansion Tank	Pressure Boundary	Carbon Steel
Filter housing	Pressure Boundary	Carbon Steel
Flex Hose	Pressure Boundary	Stainless Steel
Flexible Connector	Pressure Boundary	Stainless Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Galvanized Steel
Piping	Pressure Boundary	Stainless Steel
Restricting Orifice	Pressure Boundary	Stainless Steel
Tanks	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.13 Cranes, Hoists and Elevators System [T31]

System Description

The reactor building crane is the only inscope component for this system. The purpose of the reactor building crane is to provide the capability for moving major components for refueling operations and maintenance.

The Unit 1 reactor building crane provides service to both Unit 1 and Unit 2. It has the capability to move loads up to 125 tons with the main hook. This capability includes the handling of shield plugs, reactor vessel heads, drywell heads, steam dryers, steam separators, and the spent-fuel shipping cask. The reactor building crane main and auxiliary hooks have an electrical interlock system to prevent their potential movement over spent fuel.

Additional information may be found in Unit 1 FSAR Section 10.20 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

For reference, refueling platform equipment [F15], is discussed in Section 2.3.4.2.

Intended Functions

T31-02 – Reactor Building Crane. The reactor building crane provides the ability to handle the large loads encountered with performing refueling operations and maintenance to the reactor building. The load bearing components must maintain their passive structural integrity function within the scope of license renewal.

Component Groups Requiring an Aging Management Review

Table 2.3.4-13 Components Supporting Reactor Building Crane [T31] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Structural Support	Carbon Steel

2.3.4.14 Tornado Vents System [T38]

System Description

The purpose of the tornado vents is to act as blowout panels for venting the reactor and control building roofs under the following conditions:

- Against a wind velocity of 300 mph.
- When the internal static pressure in the building is increased to 55 lb/ft^2.
- When the temperature reaches approximately 212 °F.

A rapid depressurization of air surrounding site structures can occur if a tornado funnel suddenly engulfs a structure. Venting is accomplished by placing blowout panels, designed to fail at a pressure lower than the safe building capability for internal pressure, to relieve excess pressure in all essential parts of such structures.

Additional information may be found in Unit 2 FSAR paragraph 3.3.2.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T38-01 – Pressure Equalization. The reactor building tornado relief vents are safety related because they are required to maintain secondary containment during normal operation and during an earthquake. An inadvertent opening of the tornado vents could compromise secondary containment integrity and therefore the tornado vents are relied upon to remain closed to prevent or mitigate the consequences of accidents that could result in potential offsite exposure. The opening of the vents during a tornado is a safety function to prevent collapse of safety-related structures.

Component Groups Requiring Aging Management Review

Table 2.3.4-14 Components Supporting Tornado Relief Vent Assemblies [T38] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Screws*	Structural Support	Stainless Steel
Support Frame	Structural Support	Aluminum
Tornado Relief Vent Dome	Fission Product Barrier	Acrylic (Plexiglas G Cellcast Acrylic Polymer)

* No aging effects requiring management

2.3.4.15 Reactor Building HVAC System [T41]

System Description

The purposes of the reactor building HVAC system are to:

- Provide an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by the removal of the heat dissipated from the plant equipment.
- Promote air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust.
- Minimize the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates and/or radioiodine contamination exists.
- Provide a source of cooling to support the operation of the emergency core cooling systems (ECCS).
- Provide isolation capability to maintain secondary containment integrity and support operation of the standby gas treatment system (SGTS).

The reactor building HVAC system utilizes a combination of air conditioning, heating, and once-through ventilation. Heat removal is provided by the ventilation air and by the chilled-water (Unit 2 only) and service-water cooling coils served by the reactor and radwaste building chilled water system and the plant service water (PSW) system, respectively. Hot water heating coils, served by the plant heating system, are provided for heating.

Additional information may be found in Unit 1 FSAR Section 10.9 and Unit 2 FSAR subsection 9.4.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T41-01 – Indirect Radioactive Release Control. The reactor building HVAC system minimizes the release of potential airborne radioactivity during normal plant operation by promoting air movement from areas of lower airborne radioactivity to areas with potentially greater airborne radioactivity before final filtration and exhaust. This function also monitors the exhaust air stream for high radiation, shuts down the normal supply and exhaust systems, and initiates the SGTS.

The reactor building ventilation radiation monitoring signals that control the indirect radioactive release to the environment via the SGTS are evaluated as part of system D11. Indirect radioactive release control is the safety-related function. Dampers of the reactor building HVAC system are safety related per Criterion 3 and required for SGTS operation.

The associated T41 ductwork, which is considered nonsafety related, must retain its integrity to ensure that the SGTS can maintain a negative pressure in the reactor building. EQ criteria are selected for the isolation dampers and associated controls.

T41-02 – Essential Mechanical/Environmental Support – ECCS Room Coolers. The reactor building HVAC system provides a cooling source to support the operation of the ECCS pumps. The ECCS and corner room coolers described above have been designed to operate during and following a design basis accident to support the operation of those systems required to mitigate the consequences of an accident. The reactor core isolation cooling (RCIC) and control rod drive (CRD) room coolers are not included in this function.

T41-07 – Essential Mechanical/Environmental Support – RCIC and CRD Room Coolers. The room coolers for the RCIC and the CRD pump rooms provide reliable operation of the RCIC and CRD pumps. The RCIC and CRD pump room cooling units are not required for a safe plant shutdown following major accidents. The RCIC and CRD pump room cooling unit coils are treated as safety related with respect to maintaining the pressure boundary of the PSW system.

Component Groups Requiring an Aging Management Review

Table 2.3.4-15 Components Supporting Reactor Building HVAC System [T41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Fission Product Barrier, Pressure Boundary	Carbon Steel
Ductwork	Fission Product Barrier, Pressure Boundary	Galvanized Steel
Flow Element	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper Alloy

2.3.4.16 Traveling Water Screens/Trash Racks System [W33]

System Description

The purpose of the traveling water screens is to prevent debris from entering the portion of the intake structure from which the pumps take suction.

Larger debris are prevented from reaching the screens by the trash racks. The screen system is composed of two traveling screens, two motors, and two screen wash lines which operate in parallel to serve the common bay from which both the Unit 1 and Unit 2 pumps take suction. The specifications for both the trash racks and traveling screens require that they maintain their structural integrity following a design basis earthquake (DBE). Therefore, the pumps would continue to be protected from river debris by both the trash racks and the screens.

The normal environment for the traveling screens and trash racks is submerged in river water.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

W33-01 – Intake Structure Trash Removal. The intake structure is equipped with trash screens and rakes to keep debris out of the pump wells. The debris is removed from the screens by the screen wash water. The screens and rakes must remain structurally intact during an accident but are not required to move. Therefore, only the screens and rakes are in scope, not the motors or screen wash lines.

W33-03 – Screen Wash Isolation. Screen wash isolation in safe shutdown (SSD) mode is required during a fire to maintain SSD paths 1 and 3.

Component Groups Requiring an Aging Management Review

Table 2.3.4-16 Components Supporting Traveling Water Screens/ Trash Rack System [W33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Sight Glasses*	Pressure Boundary	Ceramic
Trash Racks	Debris Protection	Carbon Steel
Traveling Screen	Debris Protection	Carbon Steel Stainless Steel Copper Alloy*
Valve Bodies	Pressure Boundary	Carbon Steel

* No aging effects requiring management

2.3.4.17 Outside Structures HVAC System [X41]

System Description

The purpose of the intake structure HVAC system is to protect the intake structure equipment from adverse temperature conditions that could affect the reliability of the equipment. The diesel generator building HVAC system protects diesel generator building equipment from adverse temperature conditions that could affect the reliability of the equipment.

The river intake structure HVAC system consists of three 50% capacity roof-mounted exhaust ventilators, four gravity-operated louvers, and six wall-mounted unit heaters. The ventilators are powered from separate power sources. Each ventilator has a separate control station and is operated by an individual thermostat. The independent controls are powered from the motor control center (MCC) control transformer for the associated fan. Since selected plant service water (PSW) pumps operate during normal and accident conditions in the plant, the three thermostats and the individual fan control stations are located in the Unit 1 and Unit 2 PSW pump bay areas. The locations of the thermostats ensure the ventilation system is always activated when operation of the PSW pumps causes a heat buildup in the area. The six unit heaters and their associated thermostats are strategically located at different areas of the building to provide adequate area coverage for maintaining the building above freezing temperatures.

The diesel generator rooms' heating and ventilating systems consist of one power roof exhaust ventilator in each room for exhausting heat from the rooms when the generator is shut down and two 100% capacity power roof exhaust ventilators in each room for exhausting heat from the rooms during generator actuation. Two motor-operated wall air intake louvers, with fire dampers in each room, replenish the air removed by the exhaust ventilation. One louver serves as the air intake to the generator area; the other serves as the air intake to the battery rooms through the generator area.

Additional information about the system may be found in Unit 2 FSAR subsections 9.4.5 and 9.4.10.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X41-01 – Intake Structure Environmental Control. The intake structure HVAC system controls the temperature of the intake structure to ensure optimal equipment performance. This system assures that the intake structure bulk air temperature remains within a band of 40 °F to 122 °F given an outside air temperature band of 10 °F to 95 °F. This system operates from normal and emergency power sources and performs its function before, during, and after a design basis accident (DBA).

<u>X41-02 – EDG Building Environmental Control.</u> The EDG HVAC system provides temperature and air movement control to prevent the ambient temperatures in the EDG room from exceeding the maximum allowable temperature of 122 °F when the diesel is running.

<u>X41-03 – EDG Building Battery Room H_2 Control.</u> The EDG battery room ventilation system exhausts hydrogen from the battery rooms.

<u>X41-04 – EDG Switchgear Room Heating and Ventilation.</u> The EDG switchgear room heating and ventilation exhausts heat from the switchgear rooms and maintains a minimum temperature in the room.

<u>X41-05 – EDG Building Oil Storage Room Ventilation.</u> This function exhausts fumes from the oil storage room in the event of fire.

Component Groups Requiring an Aging Management Review

Table 2.3.4-17 Components Supporting Outside Structures HVAC System [X41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Bolting	Pressure Boundary	Stainless Steel
Duct Sleeve	Pressure Boundary	Carbon Steel
Flow Element	Pressure Boundary	Stainless Steel
Grating*	Missile Barrier	Carbon Steel
Tubing	Pressure Boundary	Copper

* No aging effects requiring management

2.3.4.18 Fire Protection System [X43]

System Description

The fire protection program assures, through a defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occurring. Increases in the risk of radioactive releases to the environment could occur without the fire protection program. The program consists of detection and extinguishing systems, administrative controls and procedures, and trained personnel. The defense-in-depth principle is aimed at achieving an adequate balance in these areas along with:

- Preventing fires from starting,
- Detecting fires quickly, rapidly suppressing fires that occur and limiting their damage, and
- Designing plant safety systems so that a fire which starts in spite of the fire protection program and burns for a significant period of time will not prevent essential plant safety functions from being performed.

Primary design consideration is given to locating redundant safe shutdown circuits and components in distinct areas separated by fire barriers which prevent the propagation of fire to adjacent areas. The barriers are designed to contain a design basis fire which totally involves the combustibles in the given area.

A state-of-the-art, early warning fire detection multiplex system is utilized. The system is configured around master/slave concept linked to a common command center. All devices (e.g., detectors, tamper switches, pressure switches, etc.) are wired to their respective slave panels. Signals from each of these devices are grouped according to their originating detection zone. There are approximately 260 detection zones throughout both units.

Water supply for the fire protection system inside the protected area is provided by two 300,000 gallon dedicated storage tanks. The tanks are supplied by two deep wells, each with a 700 gpm makeup pump, capable of refilling either tank within 8 hours. These water supplies are strained and filtered for normal makeup.

There are three fire pumps, two diesel engine driven and one electric motor driven. Each pump is rated for 2500 gpm capacity at 125 psi. A single 70 gpm, 125 psig pressure maintaining pump (jockey pump) is provided to keep the system filled and pressurized during low flow draw offs and in the event of system leakage.

Additional information may be found in the Hatch Fire Hazards Analysis (FHA).

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X43-01 – Cardox Fire Suppression for EDGs. The cardox fire suppression for EDGs provides an automatic gaseous total flooding fire suppression system for diesel engine compartment fire to contain and control the level of fire damage. The scope includes a rollup fire door, HVAC fire dampers, carbon dioxide discharge controls, and detection devices. The rollup fire door releasing mechanism is controlled by a nonsafety-related fusible link.

X43-02 – Halon Suppression-Remote Shutdown Panel (Unit 2). The halon suppression-remote shutdown panel provides the automatic suppression system to comply with separation requirements of safe shutdown paths located inside the remote shutdown panels according to 10 CFR Appendix R.

X43-04 – Plant Wide Fire Suppression With Water. Dedicated water storage and plantwide water distribution system to supply manual hose stations and automatic water suppression systems for areas of Plant Hatch.

This is applicable to portions of L43, T43, U43, V43, W43, X43, Y43, and Z43. The fire protection water supply is furnished from deep wells and stored in tanks. All powerblock structures consist of looped headers and dual feeds from the underground loop mains. The distribution headers supply risers for hose stations and risers for the suppression systems where practical. The water curtains in the reactor building provide separation of safe shutdown paths by serving as an equivalent fire barrier.

X43-06 – Fire Detection. Provide early warning fire detection systems to alert station personnel of incipient stage of fire development to ensure fast and timely response.

This is applicable to portions of L43, T43, U43, W43, X43, Y43, and Z43. Fire detection is necessary to comply with the original license basis described in Fire Hazards Analysis, Appendix D, and to comply with 10 CFR 50 Appendix R requirements detailed in the Plant Hatch FHA, Appendix E.

X43-07 – Penseals and Fire Barriers for Preventing Fire Propagation. Fire barriers consist of fire-rated doors, dampers, and penetration seals for the respective buildings and provide separation between safe shutdown trains to ensure a fire in any single area will not prevent safe shutdown.

This is applicable to portions of L48, R90, T43, U43, X43, and Z43. Fire barriers consist of fire doors, fire dampers, and barrier penetration seals to provide passive protection features to maintain cable separation and restrict fire to a single fire area as required under 10 CFR 50 Appendix R.

X43-08 – Manual Carbon Dioxide Fire Protection. Provide first response fire fighting capability with carbon dioxide hose reels to reduce cleanup and prevent water damage to high voltage electrical equipment. This applies only to X43. Manual hose reels are provided as an alternative to water-based hose stations.

X43-10 – Cardox Fire Suppression for the Computer Room. Provide an automatic gaseous fire suppression system for the computer room and the cable spreading room. This is a total flooding system actuated by ionization detection.

Component Groups Requiring an Aging Management Review

Table 2.3.4-18 Components Supporting Fire Protection System [X43] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Fire Doors	Fire Barrier	Carbon Steel Galvanized Steel Copper Alloy Stainless Steel Aluminum Nonmetallic, Inorganic-Gypsum Fibers, nonasbestos synthetic Nonmetallic, organic
Fire Hydrants	Pressure Boundary	Cast Iron
Fittings	Pressure Boundary	Cast Iron
Fittings	Pressure Boundary	Copper Alloy Cast Iron
Fusible Material	Pressure Boundary	Nonferrous Metal
Kaowool Hold-down Straps	Fire Barrier	Galvanized Steel
Nozzles	Flow Restriction	Aluminum Copper Alloy
Nozzles	Flow Restriction	Copper Alloy
Penetration Seals	Fire Barrier	Concrete Ceramics Carbon Steel Synthetic Fiber Elastomers
Pilot Valves	Pressure Boundary	Aluminum
Pipe Line Strainers	Pressure Boundary	Cast Iron
Piping	Pressure Boundary	Carbon Steel Aluminum Galvanized Steel Copper Alloy Cast Iron
Piping	Pressure Boundary	Carbon Steel Stainless Steel
Piping	Pressure Boundary	Carbon Steel Galvanized Steel
Pump Casings	Pressure Boundary	Cast Iron
Restricting Orifices	Pressure Boundary, Flow Restriction	Stainless Steel
Sprinkler Head Bulbs	Pressure Boundary	Ceramics

Table 2.3.4-18 Components Supporting Fire Protection System [X43] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Material
Sprinkler Head Links	Pressure Boundary	Copper
Sprinkler Heads	Flow Direction, Pressure Boundary, Flow Restriction	Stainless Steel Copper Alloy Carbon Steel
Strainer Basket	Pressure Boundary	Stainless Steel
Strainers	Pressure Boundary	Cast Iron
Tank	Pressure Boundary	Carbon Steel
Tank Insulation	Environmental Control	Organic
Tubing	Pressure Boundary	Copper Alloy
Tubing Fittings	Pressure Boundary	Copper Alloy Cast Iron Copper
Valve Bodies	Pressure Boundary	Carbon Steel Cast Iron Copper Alloy

2.3.4.19 Fuel Oil System [Y52]

System Description

The purpose of the fuel oil system is to receive, store, and supply fuel oil to other systems.

Fuel oil is provided to the diesel generator system. Diesel engine fuel for Units 1 and 2 is stored in five interconnected buried tanks. Diesel fuel is transferred to the engine day tanks using dedicated, redundant transfer pumps and piping. The diesel fuel storage tanks are filled by gravity from a truck connection through a common header.

Two of the buried tanks are dedicated to each of the Unit 1 and Unit 2 diesel generators. The remaining tank is used to supply the swing diesel (1B) to serve either Unit 1 or Unit 2. The fuel oil system transfer pumps operate continuously on demand from the day tank level controllers. Storage tank levels are monitored and alarmed (low level) in the main control room (MCR).

Additional information may be found in Unit 1 FSAR Section 8.4 and Unit 2 FSAR subsection 9.5.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y52-01 – Emergency Diesel Generator (EDG) Fuel Oil Supply. The EDG fuel oil system provides a 7 day supply of fuel oil to the diesels in the event of a loss of offsite power (LOSP). The availability of the storage tanks is needed for an extended duration LOSP, which is a more risk-significant LOSP event. This function also includes the fuel oil supply piping and the R43 instrumentation and valves in the piping from the fuel oil pumps to the EDGs.

Component Groups Requiring an Aging Management Review

Table 2.3.4-19 Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary	Carbon Steel
Discharge Head	Pressure Boundary	Carbon Steel
Flex Hose	Pressure Boundary	Stainless Steel
Manway Shell	Shelter/ Protection	Carbon Steel
Piping	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Pump	Pressure Boundary	Carbon Steel
Strainer Basket	Shelter/ Protection	Stainless Steel
Tank	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.4.20 Control Building HVAC System [Z41]

System Description

The control building HVAC system performs the following functions under normal and post accident conditions of the plant:

- Provides temperature control and air movement control, including a filtered fresh-air supply, for personnel comfort.
- Optimizes equipment performance by the removal of the heat dissipated from the plant equipment.
- Minimizes the potential of exhaust air entering into the supply air intake by exhausting at an elevated point via the reactor building vent plenum.
- Detects and limits the introduction of radioactive material into the main control room (MCR).

The control building is served by both heating and air-conditioning (A/C) subsystems and a once-through ventilation subsystem. The A/C subsystems use direct expansion of chilled water cooling coils. Heating is provided by electric or hot water heating coils. The control room, computer room, water analysis room, chemistry laboratory and health physics area, and cold laboratory are the areas served by the heating and A/C subsystems. The low pressure coolant injection (LPCI) inverter room and Unit 2 vital A/C room are served by separate coolers. All other areas of the control building are served by a once-through ventilation subsystem.

For additional information see Unit 2 FSAR subsection 9.4.7.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Z41-02 – Control Room Habitability. The control room HVAC system is designed to provide cooling and a controlled environment for personnel safety and habitability in the control room during normal and accident conditions. Also, the system provides a controlled temperature to ensure the integrity of the MCR components. The MCR environmental control system, in the pressurization mode, ensures operator protection and habitability in the MCR in the event of design basis accidents.

Z41-03 – Control Building Environmental Support. Control building HVAC provides temperature and air movement control, and removes heat dissipated from the plant equipment for the computer room, radiochemistry lab and health physics area, water analysis room, CO_2 storage tank room, station battery rooms, shift supervisor's area, Unit 1 vital AC room and cold laboratory. This function also minimizes the potential of airborne radioactivity in the health physics area.

Component Groups Requiring an Aging Management Review

Table 2.3.4-20 Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Accumulator Air Valve	Pressure Boundary	Carbon Steel
Accumulator Piping	Pressure Boundary	Carbon Steel
Accumulator Tanks	Pressure Boundary	Stainless Steel
Bolting	Pressure Boundary	Carbon Steel
Duct Gasket	Pressure Boundary	Fibers, Nonasbestos Synthetic; Elastomers, other
Duct Heater	Pressure Boundary	Aluminum
Duct Silencer	Pressure Boundary	Galvanized Steel
Ductwork	Pressure Boundary	Carbon Steel
Ductwork	Pressure Boundary	Galvanized Steel
Ductwork Flex Connector	Pressure Boundary	Fibers, Nonasbestos Synthetic; Elastomers, other
Filter Housing	Pressure Boundary	Galvanized Steel
Flow Element	Pressure Boundary	Stainless Steel
Instrument Piping	Pressure Boundary	Copper Alloy
Instrument Piping	Pressure Boundary	Stainless Steel
Louver	Pressure Boundary	Carbon Steel
Piping	Pressure Boundary	Stainless Steel
Radiation Element	Pressure Boundary	Stainless Steel
Temperature Sensor	Pressure Boundary	Stainless Steel
Tubing	Pressure Boundary	Copper
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Copper Alloy
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.5 STEAM AND POWER CONVERSION SYSTEMS

2.3.5.1 Electro-Hydraulic Control System [N32]

System Description

The purpose of the electro-hydraulic control (EHC) system is to provide control of reactor pressure during reactor startup, power operation, and shutdown. EHC also provides a means of controlling main turbine speed and acceleration during turbine startup and protect the main turbine from undesirable operating conditions by initiating alarms, trips, and runbacks.

Additional information about this system may be found in Unit 1 FSAR Section 11.2 and Unit 2 FSAR Section 10.2A.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

N32-02 – Main Turbine Pressure Regulators. Controls turbine control valve position by adjusting EHC pressure based on main steam pressure. The EHC regulators in the scope of license renewal are 1N11-N042A/B and 2N32-N301A/B. Technical specifications do not require the regulators to be operable. However, transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator. Therefore these regulators were included for conservatism.

Component Groups Requiring an Aging Management Review

Table 2.3.5-1 Components Supporting Electro-Hydraulic Control [N32] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Piping	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.3.5.2 Main Condenser System [N61] (Unit 2 Only)

System Description

The main condenser provides a heat sink for turbine exhaust steam, turbine bypass steam, and other flows such as cascading heater drains, air ejector condenser drains, exhaust from the feed pump turbines, gland seal condenser, feedwater heater shell operating vents, and condensate pump suction vents. The main condenser also deaerates and provides storage capacity for the condensate water to be reused.

The main condenser system is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 5.66×10^9 Btu/h, an inlet water temperature of 90 °F, and an average back pressure of 3.5 in. Hg absolute. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several others flows, such as exhaust steam from the feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents.

Other flows occur periodically. These originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate.

During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge from feedwater heater shells, steam-seal regulator, and various steam supply lines.

Additional information may be found in Unit 2 FSAR subsection 10.4.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

N61-03 – Post Accident Radioactive Decay Holdup. The post accident radioactive decay holdup provides a method for MSIV leakage treatment. It uses the main steam drain lines to convey the MSIV leakage during post-accident conditions to the isolated main condenser. The main condenser provides holdup and allows "plate-out" of the fission products that may leak out from the closed MSIV during post-accident conditions. MSIV leakage that enters the condenser is ultimately released to the turbine building as noncondensible gases through the low pressure turbine seal after significant plate-out of iodine.

Component Groups Requiring an Aging Management Review

Table 2.3.5-2 Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Material
Bolting	Pressure Boundary Fission Product Barrier	Carbon Steel
Condenser Shell	Fission Product Barrier Pressure Boundary	Carbon Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping	Pressure Boundary Fission Product Barrier	Carbon Steel
Preheater	Pressure Boundary Fission Product Barrier	Carbon Steel
Preheater	Pressure Boundary Fission Product Barrier	Stainless Steel
Restricting Orifices	Pressure Boundary Fission Product Barrier	Stainless Steel
Strainer	Pressure Boundary Fission Product Barrier	Carbon Steel
Thermowell	Pressure Boundary Fission Product Barrier	Stainless Steel
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Stainless Steel

2.4 STRUCTURES SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions associated with that system;
- A list of the various civil/structural component groups that are subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.4.1 PIPING SPECIALTIES [L35]

System Description

Piping specialties provide support for essential piping systems. Essential piping systems are required to maintain the integrity of safety-related and nonsafety-related systems during normal operations and transient/accident mitigation. These specialties include snubbers and pipe restraints regardless of system affiliation and also include non ASME HVAC duct supports and tube trays.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

L35-01 – Pipe Supports. Pipe supports for the reactor coolant system and subsystems are provided to ensure pressure retaining capability of the piping systems due to weight, seismic, and fluid dynamic loads. Pipe supports maintain the integrity of nonsafety functions during accident and seismic events. This includes all safety-related plant pipe supports, pipe restraints, and tubing supports regardless of master parts list (MPL) designation.

L35-02 – Nonseismic Pipe Supports. Pipe supports for nonsafety-related piping (nonseismic category) located throughout the plant are included in this function. These supports are not designed to any seismic criteria but are designed for dead weight and thermal loads only. Only those seismic category II piping supports required to support functions X43-04, W33-03, and N61-03 are included within the scope of license renewal. All other seismic category II supports are excluded from the scope of license renewal.

Component Groups Requiring an Aging Management Review

Table 2.4.1-1 Components Supporting Piping Specialties [L35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Hangers and Supports for ASME Class I Piping	Structural Support	Carbon Steel Galvanized Steel Stainless Steel*
Hangers and Supports for Non ASME Class I Piping, Tubing, and Ducts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel
Tube Trays and Covers	Structural Support; Nonsafety Related Structural Support	Stainless Steel*

* No aging effects requiring management

2.4.2 CONDUITS, RACEWAYS, AND TRAYS [R33]

System Description

The purpose of the conduits, raceways, and trays system is to provide support for a cable system with cables and penetrations selected, routed, and located to survive the design basis events established for this plant and prevent a loss of function of any system due to a cable failure.

Additional information may be found in Unit 1 FSAR Section 8.8 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R33-01 – Wire and Cable Integrity. The conduits, raceways, and trays that are mounted Seismic Category I are considered safety-related. Seismic Category I conduits, raceways and trays provide support for essential cable feeding power supplies and controls.

R33-02 – Wire and Cable Integrity- Nonsafety Related: The conduits, raceways and trays that are neither mounted Seismic Category I nor Seismic Category II/I are considered nonsafety-related. Nonsafety-related conduits, raceways and trays provide support for non-essential cable feeding power supplies and controls. Also, some nonseismic raceways are included in safe shutdown pathways.

Component Groups Requiring an Aging Management Review

Table 2.4.2-1 Components Supporting Cable Trays and Supports [R33] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Cable Trays and Supports	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Aluminum*

* No aging effects requiring management

2.4.3 PRIMARY CONTAINMENT [T23]

System Description

The purpose of the primary containment is to isolate and contain fission products released from the reactor primary system following a design basis accident (DBA) and to confine the postulated release of radioactive material.

The primary containment design employs a pressure suppression containment system which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the reactor primary system. The pressure suppression system consists of a drywell, a pressure suppression chamber (torus) which stores a large volume of water, a connecting vent system between the drywell and the pressure suppression pool, isolation valves, vacuum relief system, containment cooling systems, and other service equipment.

The pressure suppression chamber is a steel pressure vessel in the shape of a torus located below and encircling the drywell, with a major diameter of approximately 107 ft and a cross-sectional diameter of approximately 28 ft. The pressure suppression chamber contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside of the chamber for inspection.

Additional information about this system may be found in Unit 1 FSAR subsection 5.1.2 and Unit 2 FSAR subsection 6.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T23-01 – Torus/Drywell. The primary containment system provides, in conjunction with other safeguard features, the capability to limit the release of fission products in the event of a postulated DBA so that offsite doses do no exceed 10 CFR 100 guidelines. The pressure suppression pool initially serves as a heat sink for any postulated transient or accident condition in which the normal heat sink (main condenser or shutdown cooling system) is unavailable.

Component Groups Requiring an Aging Management Review

Table 2.4.3-1 Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel
Blind Flange*	Fission Product Barrier	Carbon Steel
Containment Isolation Valves *	Fission Product Barrier	Carbon Steel
Containment Isolation Valves*	Fission Product Barrier	Stainless Steel
Containment Penetrations (Mechanical only)	Fission Product Barrier	Carbon Steel Stainless Steel
Miscellaneous Steel	Structural Support; Radiation Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Piping*	Fission Product Barrier	Carbon Steel
Piping*	Fission Product Barrier	Stainless Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding	Concrete Carbon Steel
Steel Bellows (inside Vent Pipe)	Pressure Boundary; Fission Product Barrier	Carbon Steel Stainless Steel
Structural Steel	Structural Support; Shelter/Protection; Radiation Shielding; Missile Barrier; HE/ME Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support; Pressure Boundary Fission Product Barrier; Exchange Heat	Carbon Steel Stainless Steel
Tubing*	Fission Product Barrier; Pressure Boundary	Stainless Steel
Unreinforced Concrete	Radiation Shielding	Unreinforced Concrete**
Vent Pipe, Vent Header, Downcomers	Fission Product Barrier; Pressure Boundary	Carbon Steel

* Piping and valves include components from systems P51, P21, T23, G51, G11, D11, and C51. These are all included in function T23-01, Torus/Drywell.
** No aging effects requiring management

2.4.4 FUEL STORAGE [T24]

System Description

The purpose of the fuel storage system is to provide specially designed underwater storage space for the spent-fuel assemblies which require shielding during storage and handling. The fuel storage facility is located inside the secondary containment on the refueling floor.

Additional information may be found in Unit 1 FSAR Section 10.2, 10.3 and Unit 2 FSAR Section 9.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T24-01 – Spent Fuel Integrity. The fuel storage facility provides specially designed underwater storage space for the spent fuel assemblies which require shielding and cooling during storage and handling. This includes the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components.

T24-02 – New Fuel Integrity. The fuel storage facility provides specially designed dry, clean storage areas for the new fuel assemblies. This includes the concrete vault and fuel racks.

Component Groups Requiring an Aging Management Review

Table 2.4.4-1 Components Supporting Fuel Storage [T24] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support	Stainless Steel
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Fission Product Barrier	Stainless Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Reinforced Concrete	Shelter/Protection; Structural Support; Nonsafety Related Structural Support	Concrete Carbon Steel
Seismic Restraints for Spent Fuel Storage Racks	Structural Support	Aluminum
Storage Racks*	Structural Support	Aluminum
Structural Steel	Shelter/Protection; Fission Product Barrier; Structural Support	Stainless Steel

* No aging effects requiring management

2.4.5 REACTOR BUILDING [T29]

System Description

The purpose of the reactor building is to shelter and support the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment.

The building is a reinforced concrete structure with a steel superstructure. The building consists of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and prestressed exterior wall panels.
- Reinforced concrete floors with reinforced concrete beams and girders framing.
- Reinforced concrete interior walls with some blockouts filled with concrete masonry.
- Reinforced concrete roof slab on metal roof deck system supported by steel superstructure.

The reactor building completely encloses the reactor and its pressure suppression primary containment system. Also housed within the reactor building are the core standby cooling systems, reactor water cleanup demineralizer system, standby liquid control system, control rod drive system, reactor protection system, and electrical equipment components. The building is designed for minimum leakage so that the standby gas treatment system (SGTS) has the necessary capacity to reduce and hold the building at a subatmospheric pressure under normal wind conditions.

Additional information may be found in Unit 1 FSAR subsection 12.2.1 and Unit 2 FSAR Section 3.0.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T29-01 – Containment and Support. The reactor building provides primary containment during reactor refueling and maintenance operations when the primary containment is open. It also provides an additional barrier when the primary containment system is functional. Therefore, it is relied on to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines. This evaluation includes the blowout panels in the pipe-chase between the reactor building and the turbine building.

Component Groups Requiring an Aging Management Review

Table 2.4.5-1 Components Supporting Reactor Building [T29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Blowout Panels*	Structural Support; Fission Product Barrier	Aluminum
Miscellaneous Steel	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel*
Panel Joint Seals and Sealants	Shelter/Protection; Fission Product Barrier	Elastomers Nonmetallic, Inorganic
Reinforced Concrete	Structural Support; Fire Barrier; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding; Nonsafety Related Structural Support	Concrete Masonry Block Carbon Steel
Structural Steel	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel Stainless Steel

* No aging effects requiring management

2.4.6 DRYWELL PENETRATIONS [T52]

System Description

The purpose of the drywell penetrations is to provide a path for cable currents/signals to pass through primary containment to support the various modes of operation of their associated systems while maintaining primary containment integrity.

Mechanical penetrations are discussed in Section 2.4.3 (Primary Containment [T23]).

Containment penetrations include electrical penetration assemblies in addition to the mechanical penetrations referenced above. Electrical penetrations are hermetically sealed penetrations which are welded to the primary containment shell plate. They must maintain their primary containment pressure integrity function during all postulated operating and accident conditions. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

For additional information see Unit 1 FSAR Section 5.2 and Unit 2 FSAR subsection 6.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T52-01 – Primary Containment Integrity. The penetrations provide a path for cable currents/signals to pass through primary containment to support the various modes of operation of the systems associated with the cables.

Component Groups Requiring an Aging Management Review

Table 2.4.6-1 Components Supporting Drywell Penetrations [T52] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Fission Product Barrier	Carbon Steel

2.4.7 REACTOR BUILDING PENETRATIONS [T54]

System Description

The purpose of the reactor building penetrations is to allow mechanical and electrical equipment and personnel to pass through secondary containment to support the various modes of operation of their associated systems while maintaining secondary containment integrity.

Penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

Additional information may be found in Unit 1 FSAR paragraph 5.3.3.2 and Unit 2 FSAR figure 8.3-11.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

T54-01 – Secondary Containment Integrity. Reactor building electrical and mechanical penetrations allow piping and conductors to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

This function includes the structural support feature of Nelson Frames. The electrical aspect of Nelson Frames is included as part of Electrical Screening (See Table 2.5.15-1.).

Component Groups Requiring an Aging Management Review

Table 2.4.7-1 Components Supporting Reactor Building Penetrations [T54] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Structural Steel	Fission Product Barrier	Carbon Steel Galvanized Steel

2.4.8 TURBINE BUILDING [U29]

System Description

The purpose of the turbine building is to house the turbine-generator and associated auxiliaries including the condensate and feedwater systems.

The turbine building is a steel and concrete structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete floors self-supporting or supported by structural steel framing.
- Reinforced concrete or concrete block interior walls.
- Reinforced concrete turbine pedestal resting on concrete mat foundation.
- Reinforced concrete exterior walls.
- Reinforced concrete slab on metal roof deck system supported by steel framing.

Additional information may be found in Unit 1 FSAR subsection 12.2.2 and Unit 2 FSAR Section 3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

U29-01 – BOP Equipment Integrity and Support. There is no equipment or instrumentation located in the turbine building proper which would preclude the ability to shut down the reactor safely if damaged from a high-energy line failure. The turbine building is designed and constructed to ensure that it will not damage Category I structures or equipment located inside or adjacent to it in the event of a design basis event (DBE).

The cable chase area below elevation 147 ft is designed to Seismic Category I criteria. The Seismic Category I barrier between the main steam and feedwater piping located above elevation 147 ft and the cable chase area below precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building on the cables. The cables in this area provide trip inputs for the recirculation pump trip and reactor scram following generator load rejection or turbine trip originating in the turbine building. Based on these considerations, the portions of the Unit 1 turbine building and the cable chase area below elevation 147 ft are in scope for license renewal. The portions of the Unit 2 turbine building and the cable chase area below elevation 147 ft are in scope, as well as the supports over the radioactive release pathway for the main condenser.

Component Groups Requiring an Aging Management Review

Table 2.4.8-1 Components Supporting Turbine Building [U29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Radiation Shielding; Nonsafety Related Structural Support	Concrete Masonry Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

2.4.9 INTAKE STRUCTURE [W35]

System Description

The purpose of the intake structure is to protect residual heat removal service water and plant service water equipment from the influence of environmental conditions such as flooding, earthquakes, and tornadoes.

The intake structure is a concrete and steel structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and internal walls.
- Reinforced concrete floors and roof.
- Structural steel framing and grating, steel water spray and internal missile shield barriers, stairs, and platforms.

Unit 1 shares the intake structure with Unit 2. The intake structure has labyrinth access openings for protection against tornado missiles.

Additional information may be found in Unit 1 FSAR subsection 12.2.7 and Unit 2 FSAR subsection 3.8.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

W35-01 – RHRSW and PSW System Integrity. The intake structure is designed to protect equipment essential for plant shutdown from the influence of environmental conditions, such as flooding, earthquake, and tornadoes. The intake structure is a Seismic Category I structure.

Component Groups Requiring an Aging Management Review

Table 2.4.9-1 Components Supporting Intake Structure [W35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Flood Barrier; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Flow Direction; Missile Barrier; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel

2.4.10 YARD STRUCTURES [Y29]

System Description

The purpose of the yard structures is to provide equipment integrity and personnel habitability for various structures on the plant site.

Some of the structures included in Y29 are:

- The concrete wall and foundation accommodating the condensate storage tank.
- The foundation of the nitrogen storage tank.
- The service water valve pit boxes.
- The foundation for the fire pump house.
- The foundations for the two fire protection water storage tanks.
- The foundations for the two fire protection diesel pump fuel tanks.
- Underground concrete duct runs and pull boxes between Class I structures.

Additional information may be found in Unit 1 FSAR paragraph 5.2.3.9 and Unit 2 FSAR paragraph 3.8.5.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y29-01 – Equipment Integrity and Personnel Habitability. The yard structures provide equipment integrity and personnel habitability for various structures listed in the system description above.

This function is brought into scope because of the Seismic Category I foundation supporting the liquid nitrogen tank. The liquid nitrogen tank provides the safety-related back-up supply of motive gas for the drywell inerting system (T48) and the drywell pneumatic system (P70). The FSAR discusses the reliance of the safety analysis upon the liquid nitrogen tank. In addition, Safe Shutdown Pathways 1 and 2 in the FHA rely upon the liquid nitrogen tank to achieve safe shutdown in the event of a fire.

With respect to the enclosure around the condensate storage tank (CST), the wall and the CST foundation are seismically qualified to Category 1 requirements.

The service water valve boxes are in scope as they contain inscope piping for P41 system. The concrete duct runs and pull boxes that traverse the yard between various Class I structures as well as turbine building are in scope. These duct runs are used for routing safety-related circuits and provide protection to them.

The foundations for the fire pump house, fire protection water storage tanks, and fire protection diesel pump fuel tanks are also in scope.

Component Groups Requiring an Aging Management Review

Table 2.4.10-1 Components Supporting Yard Structures [Y29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Cover Plates – Pull Boxes*	Shelter/Protection; Flood Barrier	Aluminum
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

* No aging effects requiring management

2.4.11 MAIN STACK [Y32]

System Description

The purpose of the main stack is to support and protect monitoring equipment and provide for the monitoring and elevated release of gaseous effluents from the main stack system.

The main stack is a concrete cylindrical shape which consists of the following major components:

- Reinforced concrete foundation mat supported on steel "H" piles.
- Reinforced concrete truncated conical cylinder.
- Reinforced concrete internal floors.
- Reinforced concrete loading bay consisting of concrete base slab, external and internal walls, and roof.

Unit 1 shares a single main stack used to discharge gaseous waste with Unit 2. The main stack extends 120 meters above ground level.

Additional information may be found in Unit 1 FSAR subsection 5.3.4 and Unit 2 FSAR Section 11.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y32-01 – Gaseous Effluent Elevated Release. The main stack houses equipment for monitoring gaseous effluent releases and assures elevated release of these gaseous wastes to the environment.

Component Groups Requiring an Aging Management Review

Table 2.4.11-1 Components Supporting Main Stack [Y32] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Stainless Steel* Copper Alloy (Bronze)*
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Fission Product Barrier; Radiation Shielding	Concrete Carbon Steel
Structural Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel*

* No aging effects requiring management

2.4.12 EDG BUILDING [Y39]

System Description

The purpose of the diesel generator building is to house the emergency diesel generators (EDG) and their accessories essential for safe plant shutdown for both Unit 1 and Unit 2.

The diesel generator building is a reinforced concrete structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete exterior walls and interior walls.
- Reinforced concrete roof and parapet wall.

The diesel generator building houses EDGs and their accessories. The diesel generator building has labyrinth access openings for protection against tornado missiles. The diesel generator building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomena.

Additional information may be found in Unit 1 FSAR subsection 12.2.6 and Unit 2 FSAR subsection 9.4.5.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Y39-01 – EDG and Equipment Integrity. The diesel generator building provides support and equipment integrity for the EDGs which provide essential ac supply.

Component Groups Requiring an Aging Management Review

Table 2.4.12-1 Components Supporting Emergency Diesel Generator Building [Y39] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Carbon Steel
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Nonsafety Related Structural Support	Carbon Steel

2.4.13 CONTROL BUILDING [Z29]

System Description

The purpose of the control building is to house the common control room for Units 1 and 2 and associated auxiliaries.

The building is a reinforced concrete structure with steel framing. The building consists of the following major structural components.

- Reinforced concrete foundation mat.
- Reinforced concrete floors with reinforced concrete beam and girder framing.
- Reinforced concrete or concrete block interior walls and reinforced concrete columns.
- Reinforced concrete exterior walls and prestressed exterior wall panels.
- Reinforced concrete slab on metal roof deck system supported by steel framing.

Additional information may be found in Unit 1 FSAR paragraph 12.3.3.1.1 and Unit 2 FSAR subsection 3.2.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

Z29-01 – Equipment Integrity and Personnel Habitability. The control building includes the substructure, foundations, superstructure, walls, floors, and roof necessary to maintain equipment integrity and personnel habitability. The control building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomenon. Access doors are included in L48-01.

Component Groups Requiring an Aging Management Review

Table 2.4.13-1 Components Supporting Control Building [Z29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Anchors and Bolts	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Blowout Panels*	Structural Support; Fission Product Barrier	Aluminum
Miscellaneous Steel	Structural Support; Nonsafety Related Structural Support	Galvanized Steel Carbon Steel
Reinforced Concrete	Structural Support; Shelter/Protection; Missile Barrier; Nonsafety Related Structural Support	Concrete Carbon Steel
Structural Steel	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

* No aging effects requiring management

2.5 ELECTRIC POWER AND INSTRUMENTATION AND CONTROLS SCREENING RESULTS

The following system descriptions are included to provide the reader with the following information:

- A general description of the system and its purpose;
- The intended functions association with that system; and
- A list of the various electrical component groups subject to an aging management review.

Note that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries.

2.5.1 ANALOG TRANSMITTER TRIP SYSTEM [A70]

System Description

The purpose of the analog transmitter trip system (ATTS) is to monitor several critical plant parameters and provide actuation and trip signals to the following systems:

- Reactor Protection System
- Primary Containment Isolation System
- Secondary Containment Isolation System
- Core Spray System
- Residual Heat Removal System
- High Pressure Coolant Injection System
- Reactor Core Isolation Cooling
- Automatic Depressurization System
- Low-Low Set Logic
- Alternate Rod Insertion Logic
- Reactor Recirculation System
- Emergency Diesel Generators
- Safety Relief Valves

The ATTS is a solid-state electronic trip system designed to provide monitoring of process parameters. The system consists of primary sensors, master trip assemblies, slave trip assemblies, calibration units, card file assemblies, and other accessories.

Additional information may be found in Unit 1 FSAR Section 7.18 and Unit 2 FSAR Section 7.8.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

A70-01 – Process Parameter Monitoring. ATTS is an ESF support system, supporting the reactor protection system, emergency core cooling system, emergency diesel generators, low low set relief logic system, automatic depressurization system, primary containment isolation system, high pressure coolant injection, and reactor core isolation cooling by providing process parameter monitoring to allow these systems to initiate on appropriate actions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.2 NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM [A71]

System Description

The purpose of the nuclear steam supply shutoff system is to isolate the reactor vessel and various other systems which carry radioactive fluids within the primary containment to prevent the release of radioactive materials.

Sensor elements are located in the reactor vessel, drywell, main steam lines (MSLs), MSL pipe chase, turbine building, the reactor water cleanup (RWCU) system, and areas around the RWCU system. The system functions are initiated when sensors actuate and provide input to relay control circuits, which in turn initiate the closure of containment isolation valves and initiate various other functions. The other functions include annunciation, post accident monitoring system recorder chart speed control, control room pressurization, and signal input to the primary containment isolation system.

Additional information may be found in Unit 1 FSAR subsection 7.3.4 and Unit 2 FSAR subsection 7.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

A71-01 – Signal Transmission. The system supports safety-related functions associated with the reactor, including all functions, such as, group isolation signals, system trip interlocks, control room annunciation, and control room pressurization initiation.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.3 PRIMARY CONTAINMENT ISOLATION SYSTEM [C61]

System Description

The purpose of the primary containment isolation system (PCIS) is to limit fission product releases by isolating fluid systems during accident/transient conditions.

The PCIS functions are initiated when sensors monitoring critical parameters activate and provide input to relay control circuits which in turn initiate closure of containment isolation valves or initiate various other functions. The other functions include initiating SGTS, isolating reactor building ventilation, isolating refueling floor ventilation, and isolating the off-gas system exhaust.

Additional information may be found in Unit 1 FSAR Section 7.3 and Unit 2 FSAR subsection 7.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C61-01 – Primary Containment Isolation. The PCIS includes the instrumentation, controls, and actuators to perform the isolation function regardless of the master parts list (MPL) designation. Primary containment isolation limits fission product releases by isolating fluid systems during accident/transient conditions.

C61-02 – Signal Transmission. Primary containment isolation provides initiation signals to SBGT. Sensor input signals initiate automatic closure of primary containment isolation valves.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.4 REACTOR PROTECTION SYSTEM [C71]

System Description

The purpose of the reactor protection system (RPS) is to provide protection against the onset and consequences of conditions that challenge the integrity of the fuel barriers and the nuclear system process barrier by the initiation of an automatic scram.

The RPS is composed of two independent, dual channel monitor/trip systems, associated process system sensors, and annunciators. The RPS is designed to initiate a reactor scram to:

- Preserve the integrity of fuel cladding.
- Preserve the integrity of the reactor coolant pressure boundary (RCPB).
- Minimize the energy released during a loss-of-coolant accident (LOCA).

Additional information may be found in Unit 1 FSAR Section 7.2 and Unit 2 FSAR Section 7.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C71-01 – Reactivity Control. The RPS is the primary defense against all transients that lead to conditions that could damage the reactor. It is designed to initiate a reactor scram to preserve the integrity of fuel cladding and the RCPB, and minimize energy released during a LOCA.

C71-02 – Power Supply. The RPS system provides electrical power supply for various instrumentation and controls.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.5 REMOTE SHUTDOWN SYSTEM [C82]

System Description

The remote shutdown panels provide controls and indications to safely shut down the reactor for a selected number of components in a selected number of systems in the event the control room becomes uninhabitable.

Unit 1 has six remote shutdown panels located at various locations throughout the reactor building and diesel generator building. Unit 2 has a large remote shutdown panel and a remote shutdown instrument panel on the 130 ft elevation of the reactor building.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

C82-01 – Alternate Control Room. The remote reactor shutdown panel provides remote control and indication to bring the reactor to hot and cold shutdown from outside and independent of the main control room (MCR). It provides remote shutdown and supports numerous safety-related functions during an MCR evacuation.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.6 PROCESS RADIATION MONITORING SYSTEM [D11]

System Description

The purpose of the process radiation monitoring system is to provide input into the reactor protection system, primary containment isolation system, and others for system isolation.

There are two types of detectors used in the system, scintillation detectors and gas filled detectors. Scintillation detectors are used because they are the most sensitive and therefore are capable of detecting low levels of radiation. The two types of gas filled detectors are ion chamber and Geiger-Mueller detectors. Ion chamber detectors have the ability to compensate for different types of radiation. Geiger-Mueller detectors are used in systems that require a wide range of gamma detection because they are sensitive to low levels of radiation and can handle a wide range of environmental conditions.

More information on this system can be found in Unit 1 FSAR Section 7.12 and Unit 2 FSAR Section 11.4.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

D11-01 – Main Steam Line Radiation Monitoring. Main steam line radiation monitoring provides indication of abnormal increases in main steam gamma radiation for group 1 isolation.

D11-06 – Primary Containment Gamma Radiation Monitoring (Wide Range). The wide range primary containment radiation monitors are used for measuring gross gamma radiation in the drywell and suppression pool, before, during, and after a LOCA.

D11-12 – Reactor Building Ventilation Radiation Monitoring. This includes the reactor building vent radiation monitoring signals to support the reactor building HVAC indirect radiation release control, secondary containment isolation and standby gas treatment start functions.

D11-13 – Main Control Room Intake Radiation Monitoring. The main control room HVAC air intake is monitored to signal the system to transfer to pressurization mode upon abnormal radiation conditions.

D11-14 – Refueling Floor Ventilation Radiation Monitoring. This includes the refueling floor ventilation radiation monitoring signals to support the reactor building HVAC indirect radiation release control, secondary containment isolation and standby gas treatment start functions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.7 HEAT TRACE SYSTEM [G13]

System Description

The purpose of the heat trace system is to maintain piping, instrumentation, and equipment in working order during below freezing temperatures. A primary function is to maintain the sodium pentaborate solution in the standby liquid control system at a temperature high enough to prevent precipitation and solidification of the solution.

Standby liquid control storage tank temperature is maintained by adjusting the storage tank heater-indicating controller to maintain temperature between 65 °F and 75 °F to prevent precipitation of the sodium pentaborate from solution. Thermostat controlled heat tracing is run along the pump suction piping to maintain suction piping solution temperature. A temperature versus concentration curve is monitored to ensure that a 10 °F margin will be maintained above saturation temperature.

Additional information may be found in Unit 2 FSAR paragraph 4.2.3.4.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

G13-01 – Freeze Protection. Freeze Protection maintains piping, instrumentation, and equipment in working order during below freezing temperatures. This function also includes the heat tracing function of the standby liquid control boron control required for anticipated transient without scram compliance.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.8 MAIN CONTROL ROOM PANELS SYSTEM [H11]

System Description

The purpose of the main control boards is to provide display, recording, and alarm to enable plant operators to monitor and control the equipment necessary for normal operations and transient/accident mitigation.

The actual controls for each system are included in this system.

Additional information may be found in Unit 1 FSAR Section 7.16 and Unit 2 FSAR Section 3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

H11-01 – Operator Information and Control. The main control boards provide display, recording and alarm to enable plant operators to monitor and control the equipment necessary for normal operations and transient/accident mitigation. The actual controls for each system are included in this function.

Component Groups Requiring an Aging Management Review

Table 2.5.8-1 Components Supporting Electrical Panels, Racks & Cabinets [H11] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Electrical Panels, Racks, and Cabinets	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Carbon Steel

2.5.9 IN-PLANT AUXILIARY CONTROL PANELS SYSTEM [H21]

System Description

The purpose of the auxiliary control panels is to provide system information and control to allow operators to operate equipment from outside the main control room (MCR) in the reactor building, turbine building, and other auxiliary buildings.

The actual controls for each system are included in specific functions for the respective system.

Additional information may be found in Unit 1 FSAR Section 7.16 and Unit 2 FSAR Section 3.10.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

H21-01 – Equipment Support and Integrity. The auxiliary control boards provide support for essential equipment. The actual controls for each system and are included in the specific functions for the respective system.

H21-02 – Operator Information and Control. In-plant auxiliary control panels provide system information and control to allow operators to operate equipment from outside the MCR in the reactor building, turbine building, and other auxiliary buildings.

Component Groups Requiring an Aging Management Review

Table 2.5.9-1 Components Supporting Instrument Racks, Panels, & Enclosures [H21] Intended Functions and Their Component Functions

Structural Component	Component Functions	Material
Instrument Racks, Panels, and Enclosures	Structural Support; Nonsafety Related Structural Support	Carbon Steel

2.5.10 PLANT AC ELECTRICAL SYSTEM [R20]

System Description

The entire auxiliary power distribution system, station service, and emergency service systems consisting of both 1E and Non-1E systems, distribute power to all ac auxiliaries required to startup, operate, and shut down the plant. None of the plant's AC electrical system above 4 kV is in scope.

The emergency service portion Class 1E distributes power to all loads essential to plant safety and normal plant operation ensuring power is available to perform a safe plant shutdown.

The auxiliary power distribution system distributes power to all auxiliaries necessary for normal plant operation.

The station auxiliary ac power system is divided into two portions: one for normal Non-Class 1E service and one for emergency Class 1E service. The emergency service portion distributes ac power required to shut down the reactor, maintain the shutdown condition, and operate all safety-related equipment necessary to mitigate the consequences of major accident conditions. The entire station auxiliary ac power system, both normal and emergency service portions, distributes power to all ac auxiliaries required to start up, operate, and shut down the plant.

Additional information may be found in Unit 1 FSAR Sections 8.3 and 8.7 and Unit 2 FSAR subsection 8.3.1.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R20-01 – 1E AC Electrical Supply. The 1E ac electrical plant supply provides essential plant equipment.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.11 DC ELECTRICAL SYSTEM [R42]

System Description

The purpose of the dc distribution system is to provide reliable power from a rectified ac source (battery charger) with a battery backup to supply dc loads, control power, logic power, and inverters for all operational modes.

The battery system provides an uninterruptible source of power to normal Non-Class 1E and emergency Class 1E loads such as motors, circuit breaker controls, operation of logic and control relays, emergency lighting, etc. The emergency power is required to safely shutdown the reactor, maintain the reactor in a shutdown condition, and operate all auxiliaries necessary for plant safety under all plant operational modes.

The dc electrical system includes the following:

• 125/250 V station battery system	Class 1E
• 125 V diesel generator battery system	Class 1E
• 125 V cooling tower battery system	Non-Class 1E
• 24/48 V instrumentation battery system	Non-Class 1E
• Battery for 120/240 V vital ac system	Non-Class 1E

Additional information may be found in Unit 1 FSAR Section 8.5 and Unit 2 FSAR subsection 8.3.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R42-01 – Plant 1E dc Electrical Supply. The dc electrical system provides reliable power to the 125/250 VDC plant dc electrical system and dc metering and relaying.

R42-02 – EDG 1E dc Electrical Supply. The EDG dc electrical system provides reliable power to the 125 VDC EDG electrical system and dc metering and relaying.

R42-05 – Diesel Fire Pump dc Supply. The diesel fire pump dc electrical system provides the necessary starting current for the diesels and the control power for the diesel fire pumps.

R42-07 – Appendix "R" Emergency Lighting. Emergency lights are used to illuminate entrances/exit ways and safety-related equipment in case of a loss of offsite power/power failure.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.12 PLANT COMMUNICATIONS SYSTEM [R51]

System Description

The purpose of the plant communications system is to allow key personnel to communicate information about plant conditions and other pertinent information.

The intrasite communication system consists of a public address system; a private, dial telephone system; and a two-way radio communication system provided for paging and communication. The public address system which consists of handsets, amplifiers, loudspeakers, multitone generator, and associated equipment provides convenient, effective paging, and private conversational service. The private, automatic exchange dial telephone system is an electronic system of modular design utilizing stored program control and time division switching. A separate, two-way radio communication is provided to permit communication with mobile units and base stations within the range of the plant.

Additional information may be found in Unit 1 FSAR Section 10.15 and Unit 2 FSAR subsection 9.5.2.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

R51-01 – Personnel Communication. Personnel communication provides reliable communication via the page system, the intraplant telephone system, sound powered phones, public address system, and private dial telephones.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.13 POWER TRANSFORMERS SYSTEM [S11]

System Description

The inscope components for this system are the CD transformers. The function of these transformers is to provide power to 600V busses C or D from 4160V bus F during station blackout.

The transformers operate by dropping the voltage from 4160 volts to 600 volts.

Additional information may be found in Unit 1 FSAR Section 8.3 and Unit 2 FSAR Section 8.3.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

S11-02 – Emergency Diesel Generator 1B AC Supply. The CD transformers provide a path between 4160 volt bus F and 600-volt busses C or D during station blackout conditions.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.14 EMERGENCY RESPONSE FACILITIES SYSTEM [X75]

System Description

The purpose of the emergency response facilities is to help the plant operators, shift technical advisors, supervisory personnel, and the NRC in rapidly assessing the plant safety status during normal, transient, and accident conditions.

The NRC-emergency response data system (NRC-ERDS) is the response to the ERDS Rule published in 10 CFR 50 in 1991. It is used during an Alert emergency classification or higher to transmit certain data to the NRC operations center in Rockville, Maryland. The X75 system includes the safety parameter display system (SPDS), the technical support center (TSC) HVAC system, and the ERDS.

For additional information see Unit 1 FSAR Section 7.21 and Unit 2 FSAR Section 7.9.

The above system description is general information provided as an aid in the review of this license renewal application. As described in Section 2.1.2, the initial scoping was performed on the basis of functions. The following intended functions have been assigned to be primarily associated with this system. Note, however, that functions cross over traditional system nomenclature boundaries so that the intended functions, in some cases, are supported by components with various system designations. The intended function descriptions convey the extent to which the function may extend into other systems.

Intended Functions

X75-01 – Class 1E Signal Isolation. Historical and real-time data involve circuits for which Class 1E cabling must meet separation criteria. These systems could provide erroneous or misleading data to operators in response to an accident if failures occurred in the associated equipment.

Component Groups Requiring an Aging Management Review

Identification of electrical components is presented in Section 2.5.15.1.

2.5.15 PLANTWIDE SCOPING AND SCREENING RESULTS – ELECTRICAL AND INSTRUMENTATION AND CONTROLS

This section presents the results of the screening process for electrical components and commodities. As described in Section 2.1.4 of Scoping Methodology, the list of electrical components subject to an AMR is determined on a plantwide basis by compiling a list of all electrical component types installed in the plant, then applying the scoping and screening criteria in the Rule to determine those component types subject to an AMR. The resulting list is an encompassing list of component types, not individual components. For example, cable is listed as a component type. Individual circuits are not evaluated to determine whether they are in scope. The list of component types subject to an aging management review has been further reduced by application of the scoping criteria to the component types which meet the screening criteria. These criteria are found in 10 CFR 54.4(a). Any component type which does not meet the scoping criteria in this section on a generic basis does not require an aging management review. The comprehensive list of electrical component types is included in Table 2.1-1.

2.5.15.1 Electrical Components Which Require an Aging Management Review

After applying the scoping and screening criteria of Section 2.1.2 and 2.1.4 to the comprehensive list of electrical component types in use at Plant Hatch (see Table 2.1-1), the following component types were found to meet the scoping and screening criteria, and thus, require an aging management review.

Table 2.5.15-1 Components Supporting Plantwide Electrical Intended Functions and Their Component Functions

In-Scope Component	Component Function	Material
Cable* (Inside Containment)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Tinned and Bare Copper
Cable (Outside Containment)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Tinned and Bare Copper
Electrical Connectors, Splices, Terminal Blocks*	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper
Electrical Penetration** Assemblies (See Section 4)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Painted Steel Stainless Steel
Nelson Frames*	Fission Product Barrier Fire Protection	Various Polymers Galvanized and Painted Steel
Phase Bussing*	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper

* No aging effects requiring management

** All electrical penetration assemblies are the subject of a TLAA in Section 4.

2.6 GENERAL REFERENCES

1. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, The License Renewal Rule."

2. NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," March 1996.

3. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," 56 FR 31324, July 10, 1991.

4. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear power Plants, "60 FR 22491, May 8, 1995.

5. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, "56 FR 64976, December 13, 1991.

6. 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

7. "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," Regulatory Guide 1.154.

Section 3

AGING MANAGEMENT REVIEW RESULTS

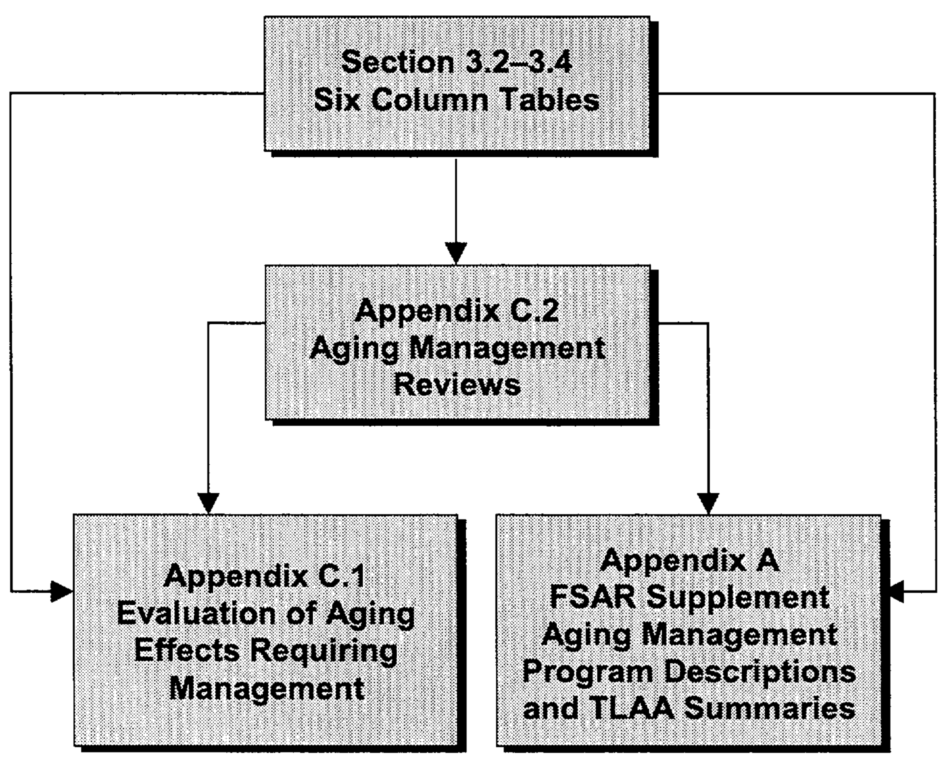
CONTENTS

3.0 AGING MANAGEMENT REVIEW RESULTS

Aging Management Review Information Layout

The relationship between the various elements of the application, as relates to the aging management reviews, is presented by the block diagram on Figure 3.0-1. The application has been arranged so that all review begins with the six-column tables in sections 3.2 through 3.4. These tables present an overview of the aging management review results. Each line item in a table represents a component group subject to an aging management review. The appendix C.2 aging management review section associated with each line item directs the reviewer to the aging management review summary. The aging effects requiring management are listed in the tables with direction to the related appendix C.1 section where the aging effects are evaluated. Credited programs and activities are identified in the tables with direction to the related appendix A program descriptions. However, details of how the credited activities manage the aging effects, in terms of program attributes, are provided in the applicable appendix C.2 section.

Figure 3.0-1 Aging Management Review Process Map



Plant-wide scoping results are presented in section 2.2. The component types subject to aging management review are identified and listed, pursuant to the requirement in 10 CFR 54.21(a)(1), on a system-by-system basis, grouped by discipline, in sections 2.3 through 2.5.

This section presents the results of the aging management reviews performed to support the application. Sections 3.2 through 3.4 present in a tabular format the component types subject to aging management review, the aging effects requiring management, and the programs credited to manage the aging effects. The tables are arranged to be generally consistent with the presentation suggested in the NRC Standard Application Format, and parallel the three-column tables that present the scoping and screening results in sections 2.3 through 2.5.

Consolidation of Component Groups into Commodity Groups

The component types listed in the tables in sections 2.3 through 2.5 were grouped according to the methodology described in section 2.1, based on similar component types, materials, and environments. Additional consolidation of component groups into groups called commodity groups was accomplished prior to performing aging management reviews. The following discussion, while not required by the rule, is provided as information to assist in the review of the Plant Hatch application for a renewed operating license.

Figure 3.0-2 illustrates the process of consolidating component groups into commodity groups. First, as discussed in section 2.1, systems, structures, and functions were identified and evaluated. Each in-scope function in Figure 3.0-2 represents an intended function.

The line in Figure 3.0-2 labeled "Components and Component Types Subject to AMR" illustrates the process of identifying and grouping components that support each intended function. Membership in a component group is based on the component type, its materials of construction, and its internal and external environments, as applicable.

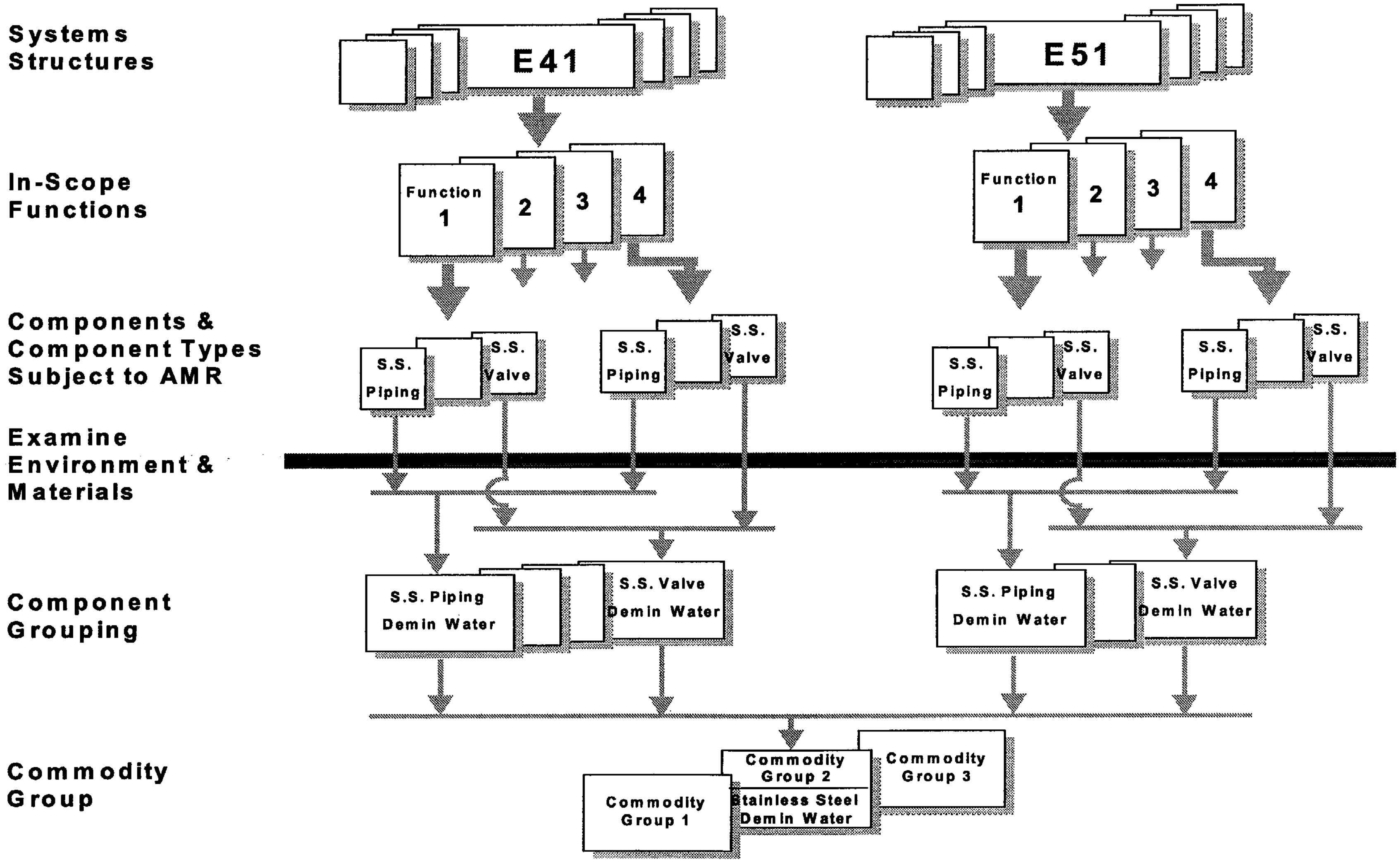
Figure 3.0-2 depicts the further consolidation of component groups across systems or structures. This consolidation of groupings can occur because a number of intended function evaluation boundaries envelope similar components in terms of their materials and environments. For example, the high pressure coolant injection and the reactor core isolation cooling systems at Plant Hatch have similar environments and were constructed from similar materials. Thus, for purposes of aging management review, a component group in an intended function evaluation boundary containing components of the high pressure coolant injection system would be like the same component group in a related intended function evaluation boundary associated with the reactor core isolation cooling system.

Finally, Figure 3.0-2 illustrates the further grouping of these component groups with other component groups having similar materials and environments. For example, stainless steel piping and stainless steel valves with the same internal and external environments can be grouped together into a commodity group. The aging management review summaries in appendix C.2 were performed on the final set of consolidated component groups. These groupings are called commodity groups.

Aging Effects Determination in the Application

Section C.1 of appendix C presents a systematic approach to identification, categorization, and evaluation of plant environments and materials. This systematic assessment evaluated a set of aging effects drawn from an extensive review of industry literature that represents the collective experience of the U.S. nuclear power industry. Each combination of plant environment and component material was assessed, and aging effects were demonstrated as requiring aging management or not requiring aging management in the context of 10 CFR 54.21(a)(3). The complete assessment for each environment/material combination is

Figure 3.0-2 Commodity Group Construction Process



contained in supporting documentation and is not provided in the application. The discussion in appendix C.1 presents those environment/material combinations for which the assessment concluded that aging management is required for one or more aging effects. In general, aging effects not requiring management for an environment/material combination are not presented in the application. Plant Hatch-specific operating experience was examined for each commodity group in appendix C.2, in part, to identify whether other aging effects specific to Plant Hatch should also be addressed. The results of the Hatch-specific operating experience review was incorporated into the aging effects determination presented in section C.1.

Aging Management Reviews

Section C.2 of appendix C presents summaries of the aging management reviews performed on the commodity groups that represent the set of component types subject to aging management review as specified in 10 CFR 54.21(a)(1). The component types were previously listed in sections 2.3 through 2.5. Each C.2 subsection contains the following headings and information:

1. **Descriptive Title for AMR Summary** - The subsection title is generally descriptive of the materials and environment that define a commodity group. For example, "Aging Management Review for Non-Class 1 Stainless Steel Components Within the Demineralized Water Environment" describes stainless steel components that are exposed to demineralized water. A brief description of the commodity group and a list of the associated component types included within the commodity group evaluation is provided.
2. **Systems** -This subheading serves as a placeholder for listing the principal systems with components belonging to the commodity group, and provides a reference back to the application section that identifies the intended functions associated with the commodity group. Figure 3.0-2 illustrates how component types supporting various intended functions are rolled up into the commodity groups. Note that component types with system numbers other than those listed for a particular aging management review summary may be included due to the cross-system establishment of intended function evaluation boundaries.
3. **Aging Effects Requiring Management** - A list of aging effects requiring management, along with the associated aging mechanisms applicable to the commodity group is presented. These aging effects and associated mechanisms were derived from reviews of textbook information, NRC correspondence, industry guidelines, industry reports relating to aging management, and operating experience (see the below discussion on operating experience). Section C.1 of Appendix C provides additional information on these aging effects and associated aging mechanisms. Links to the applicable C.1 information are also provided.
4. **Aging Management Programs** - Once the set of aging effects requiring management was identified for a particular commodity group, a list of aging management programs credited for managing aging of structures or components within the commodity group was produced. This list was compiled by examining the aspects of current programs in plant procedures and program documents. The list includes any new programs or activities to be credited for managing the aging effects. This list also provides links to the applicable Appendix A program descriptions.

5. **Demonstration of Aging Management** - The remainder of each C.2 subsection constitutes the demonstration that the effects of aging are adequately managed during the renewal term. This is accomplished by three complementary sections:

   - For each identified aging effect requiring management, a subsection title descriptive of the aging effect and a brief discussion are provided to present how specific features of applicable aging management programs and activities serve to manage age related degradation of structures and components within the commodity group under evaluation.

     These aging management programs and activities are evaluated to determine if they are applicable to the specific structures or components under evaluation and contain acceptance criteria against which the need for corrective actions will be evaluated. Additionally, aging management objectives including mitigation, detection, and correction of age related degradation are discussed. These text discussions present how aging management programs exhibit the attributes of an effective aging management program in the aging management program assessment tables.

     The broader program descriptions for the activities credited are found in appendix A. The combination of information in the appendix C.2 evaluations and appendix A provides the complete description of the programs to manage aging in the renewal term.

   - The results of a review of operating experience is provided at the conclusion of each aging management review summary or, where applicable, at the end of each environmental evaluation. Operating experience is utilized to verify that all aging effects requiring management were identified by textbook information and industry guidance, and to asses the overall adequacy and effectiveness of current aging management programs credited with managing age related degradation. What follows is a discussion of the methodology employed to produce a comprehensive survey of applicable operating experience:

     Industry experience was collected from resources such as NRC generic letters, bulletins and information notices, GE service information letters, INPO significant operating event reports and topical information from various industry working groups. Plant-specific information was derived through plant walk downs, interviews and records searches.

     Southern Company mechanical, electrical and civil engineers conducted several plant walk downs to gain first hand knowledge of the material condition of the accessible portions of Plant Hatch systems, structures and components. These walk downs were purposefully conducted in advance of personnel interviews and records searches to gain an unbiased view of the material condition of the plant.

     After the plant walk downs, site and corporate interviews were conducted in order to understand the overall maintenance history of SSCs within the scope of license renewal. Coupled with the other components of the AMR process, this effort provided insights as to where the dominant areas of concern might be.

     Having gained information from the plant walk downs and interviews with site and corporate engineers, a large condition reporting database was then searched. This database of more than 37,000 records represented approximately 5 years of plant history, covering the period 1995 through 1999. These searches were conducted using smart-search techniques to provide reasonable assurance that potentially age related problems reported in the database were found. Follow up investigations and interviews were then conducted when the search results indicated reports of potentially age related degradation.

- Finally, aging management program assessment tables present how the various programs credited serve to manage aging of structures or components. These tables list 10 attributes of an effective aging management program in the left column. The right column shows what combination of activities is being credited as satisfying the attribute.

Appendix C.2 is presented in present tense, except for discussions of operating experience which are, of course, past tense. Any specific commitments not part of a program or activity credited in Appendix A are presented in future tense. Appendix A describes existing programs and activities in present tense and enhancements to existing programs or activities and new programs or activities in future tense.

Results

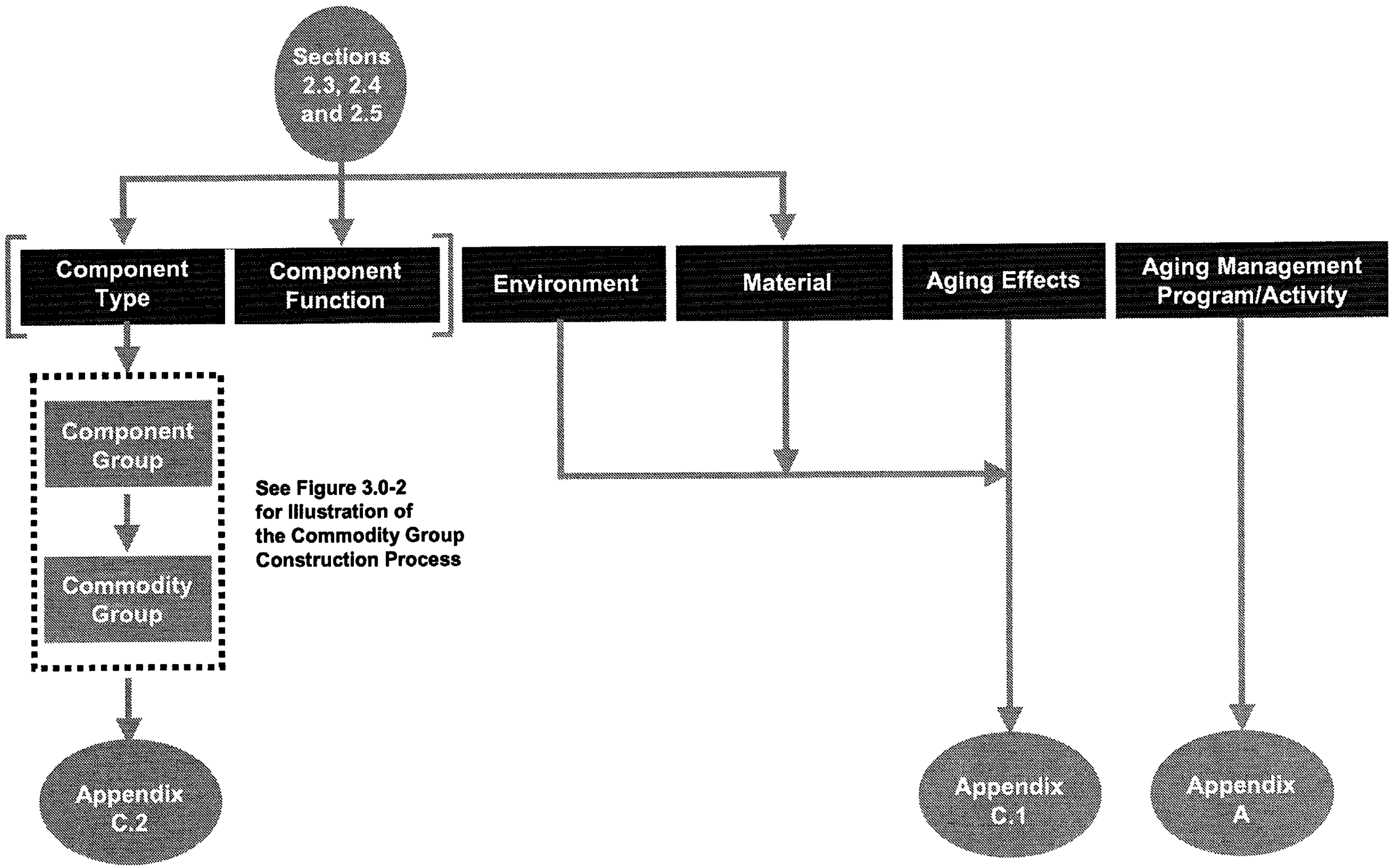
The results of the aging management reviews are presented in sections 3.2 through 3.4 in tabular form. A table is provided for each system or structure with at least one function within the scope of license renewal. These tables provide the following items for each system or structure:

- A component group with a reference to the applicable appendix C.2 aging management review summary for the commodity group in which each component group is evaluated.
- The component function(s) for each component group.
- The environments for each component group.
- The materials of construction for each component group.
- The aging effects requiring management for the component group, with a reference to the applicable C.1 section that discusses the aging effects.
- The programs credited for managing the aging effects, with a reference to the applicable appendix A program descriptions.

It must be noted that condition monitoring programs, such as one time inspections or the ISI Program, utilize representative sample populations with emphasis on the locations most susceptible to age-related degradation. Therefore, although these programs may not provide for specific inspection of the component group under consideration, they are judged to bound or otherwise provide pertinent inspection data concerning common aging effects within component groups having similar materials and environments (and in some cases more limiting conditions) and thereby comprise a portion of the aging management demonstration for the component group under consideration. For example, while the ISI Program does not specifically perform visual inspections of stainless steel piping for pitting and crevice corrosion, it does provide for periodic VT-1 visual inspections of large bore valves. These visual examinations would detect pitting or crevice corrosion in the valves and may be applied to the piping since the environmental conditions and material susceptibilities that allow for the possibility of crevice corrosion or pitting are present in both component groups. In this case, the ISI Program is credited to monitor pitting and crevice corrosion with all applicable stainless steel components, even though only stainless steel valve bodies are inspected. A similar situation occurs concerning the FAC Program. This program provides for volumetric examinations of piping to determine the amount of degradation due to flow accelerated corrosion. While this program does not specifically examine valve bodies for flow accelerated corrosion, valves are included within the mathematical models used to select inspection points. However due to the greater wall thickness values associated with valves, these components are at much lower risk of failure due to FAC and are not generally considered for inspection. In this case, volumetric inspection of the piping is judged to bound any age-related degradation within the valve bodies.

The relationship of the summary information presented in the six-column tables in section 3-2 through 3-4 with the detailed information in the various sections of the application is depicted in Figure 3.0-3.

Figure 3.0-3 Correlation of 6-column Tables to Sections of the Application



3.1 COMMON AGING MANAGEMENT PROGRAMS

See appendix A for the Common Aging Management Programs.

3.2 MECHANICAL SYSTEMS

The following tables provide the mechanical component types that are subject to an aging management review. The aging management for external surfaces is covered in section C.2.4.1. Throughout the tables, cracking is listed as an aging effect where no aging management program is specified. In these cases, cracking is managed by a TLAA. These are also covered in section C.2. No provisions have been made in these summary tables to address these items, since the external surface environments are applicable across systems.

3.2.1 REACTOR

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Appurtenances / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Nickel Based Alloy Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Attachments and Connecting Welds / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Carbon Steel Low Alloy Steel Nickel Based Alloy Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Closure Studs / C.2.1.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Low Alloy Steel	Cracking	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Component Cyclic or Transient Limit Program
Control Rod Drive / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel	Cracking	Inservice Inspection Program Reactor Water Chemistry Control
Core Spray Internal Piping / C.2.1.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Program Inservice Inspection Program Reactor Water Chemistry Control

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Core Spray Sparger / C.2.1.1.2	Pressure Boundary Flow Distribution	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel and Internals Program Inservice Inspection Program Reactor Water Chemistry Control
CRD Housing and CR Guide Tubes / C.2.1.1.2	Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Dry Tube Weld to Guide Tube /C.2.1.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Cracking	Inservice Inspection Program Reactor Water Chemistry Control
Jet Pump Assemblies / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel Cast Austenitic Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Nozzles /C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Low Alloy Steel	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Penetrations / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Nickel Based Alloy Stainless Steel	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control
Safe Ends / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Stainless Steel Low Alloy Steel Carbon Steel Nickel Based Alloy	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program

Table 3.2.1-1 Aging Effects Requiring Management for Components Reactor Assembly System [B11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Shell and Closure Heads / C.2.1.1.1	Pressure Boundary Fission Product Barrier Structural Support	Reactor Water	Low Alloy Steel	Loss of Fracture Toughness	Reactor Pressure Vessel Monitoring Program Component Cyclic or Transient Limit Program
Shroud / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel and Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Shroud Supports / C.2.1.1.2	Pressure Boundary Structural Support	Reactor Water	Stainless Steel Nickel Based Alloy Low Alloy Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control
Thermal Sleeves / C.2.1.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel Nickel Based Alloy	Cracking	Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program
Top Guide / C.2.1.1.2	Structural Support	Reactor Water	Stainless Steel	Cracking	Boiling Water Reactor Vessel Internals Program Inservice Inspection Program Reactor Water Chemistry Control

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.1.1.6 (Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload	Torque Activities Inservice Inspection Program
Bolting / C.2.2.10.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Crack Growth Monitor / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Flow Nozzle / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.2.1.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections Flow Accelerated Corrosion Program
Piping / C.2.2.1.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.2.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.2.3.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Piping / C.2.2.9.1 (Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Inservice Inspection Program Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Restricting Orifice / <u>C.2.1.1.4</u> (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	<u>Reactor Water Chemistry Control</u> <u>Component Cyclic or Transient Limit Program</u> <u>Inservice Inspection Program</u> <u>Treated Water Systems Piping Inspections</u>
Thermowell/ <u>C.2.2.9.1</u> (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	<u>Gas Systems Component Inspections</u> <u>Passive Component Inspection Activities</u>
Thermowell / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Valve Bodies / <u>C.2.2.1.1</u> (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control <u>Flow Accelerated Corrosion Program</u> <u>Galvanic Susceptibility Inspections</u> Treated Water Systems Piping Inspections
Valve Bodies / <u>C.2.2.1.2</u> (non-Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1 (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Inservice Inspection Program Passive Component Inspection Activities

Table 3.2.1-2 Aging Effects Requiring Management for Components Supporting Nuclear Boiler System [B21] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.1.1.3 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Program Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Valve Bodies / C.2.1.1.4 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Valve Bodies / C.2.1.1.5 (Class 1)	Pressure Boundary Fission Product Barrier	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Valve Bodies / C.2.2.9.2 (non-Class 1)	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies/ C.2.2.2.2 (non-Class 1)	Pressure Boundary Fission Product Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

3.2.2 REACTOR COOLANT SYSTEMS

Table 3.2.2-1 Aging Effects Requiring Management for Components Supporting Reactor Recirculation System [B31] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting/ C.2.1.1.6 (Class 1)	Fission Product Barrier, Pressure Boundary	Containment Atmosphere	Carbon Steel	Loss of Preload Loss of Material Cracking	Inservice Inspection Program Torque Activities
Flow Nozzle/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Piping / C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections
Pump Casings and Cover/ C.2.1.1.5 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Thermowell/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections

Table 3.2.2-1 Aging Effects Requiring Management for Components Supporting Reactor Recirculation System [B31] Intended Functions and Their Component Functions (Continued)

Mechanical Component	**Component Functions**	**Environment**	**Material**	**Aging Effects**	**Aging Management Program/Activity**
Valve Bodies / C.2.1.1.5 (Class 1)	Fission Product Barrier Pressure Boundary	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking Loss of Fracture Toughness	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program
Valve Bodies/ C.2.1.1.4 (Class 1)	Fission Product Barrier, Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Inservice Inspection Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections

3.2.3 ENGINEERED SAFETY FEATURES (ESF) SYSTEMS

Table 3.2.3-1 Aging Effects Requiring Management for Components Supporting Standby Liquid Control System [C41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Pump Accumulators/ C.2.2.4.1	Pressure Boundary	Borated Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Protective Coatings Program
Pump Casing / C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Tanks/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Thermowell/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies/ C.2.2.4.2	Pressure Boundary	Borated Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Conductivity Element / C.2.2.3.2	Fission Product Barrier, Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Heat Exchanger Channel Assembly / C.2.2.11.1	Pressure Boundary	Raw Water	Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Heat Exchanger Impingement Plate / C.2.2.11.1	Shelter/ Protection	Torus Water	Stainless Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Suppression Pool Chemistry Control
Heat Exchanger Shell / C.2.2.11.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Inservice Inspection Program Suppression Pool Chemistry Control
Heat Exchanger Tube Sheet / C.2.2.11.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	Suppression Pool Chemistry Control RHR Heat Exchanger Augmented Inspection and Testing Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Heat Exchanger Tube Sheet / C.2.2.11.1	Pressure Boundary	Raw Water	Stainless Steel Clad Carbon Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Heat Exchanger Tubes / C.2.2.11.1	Pressure Boundary Fission Product Barrier, Exchange Heat	Torus Water	Stainless Steel	Cracking Loss of Material Loss of Heat Exchanger Performance	Suppression Pool Chemistry Control RHR Heat Exchanger Augmented Inspection and Testing Program
Heat Exchanger Tubes/ C.2.2.11.1	Fission Product Barrier, Pressure Boundary Exchange Heat	Raw Water	Stainless Steel	Cracking Loss of Material Fouling Loss of Heat Exchanger Performance	RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Piping / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Casings / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Casings - Bowl Assembly/ C.2.2.6.2	Pressure Boundary	Raw Water	Cast Austenitic Stainless Steel	Loss of Material Flow Blockage Cracking Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Pump Discharge Head / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Pump Sub Base / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Restricting Orifices / C.2.2.3.2	Fission Product Barrier, Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifices / C.2.2.3.2	Fission Product Barrier, Pressure Boundary, Flow Restriction	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifices / C.2.2.6.2	Pressure Boundary, Flow Restriction	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.3-2 Aging Effects Requiring Management for Components Supporting Residual Heat Removal System [E11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Strainer Bodies / C.2.2.6.1	Debris Protection	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program
Strainers / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Tubing / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Flow Blockage	PSW and RHRSW Chemistry Control Program PSW and RHRSW Inspection Program Structural Monitoring Program
Valve Bodies / C.2.2.3.1	Pressure Boundary, Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspection Treated Water Systems Piping Inspection
Valve Bodies/ C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Galvanic Susceptibility Inspections Structural Monitoring Program

Table 3.2.3-3 Aging Effects Requiring Management for Components Supporting Core Spray System [E21] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Casings / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Restricting Orifice / C.2.2.3.2	Fission Product Barrier, Pressure Boundary, Flow Restriction	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspection
Strainers / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Valve Bodies / C.2.2.3.1	Fission Product Barrier, Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspection

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary Fission Product Barrier	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flexible Connector / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Dry Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Flow Accelerated Corrosion Program
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Program Treated Water Systems Piping Inspections
Piping / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections
Piping/ C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Pump Baseplate / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Pump Casings / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.1.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.2.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Program Treated Water Systems Piping Inspections
Restricting Orifice / C.2.2.9.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Suction Strainer/ C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell /C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Turbine / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and CST Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.3-4 Aging Effects Requiring Management for Components Supporting High Pressure Coolant Injection System [E41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary Fission Product Barrier	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flexible Connectors / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Galvanic Susceptibility Inspections Flow Accelerated Corrosion Program Treated Water Systems Piping Inspections
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.1.2	Pressure Boundary Fission Production Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.3.1	Pressure Boundary Fission Production Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Pump Baseplate / C.2.4.1	Structural Support	Air	Carbon Steel	Loss of Material	Protective Coatings Program
Pump Casing / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices / C.2.2.2.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices / C.2.2.9.2	Pressure Boundary, Flow Restriction Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Steam Trap / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections Flow Accelerated Corrosion Program
Steam Trap / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Steam Trap / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Steam Trap / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Strainer- Steam Exhaust/ C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Suction Strainer / C.2.2.3.2	Debris Protection	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Thermowell / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Thermowell / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Turbine / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.1	Pressure Boundary Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.3.2	Pressure Boundary Fission Product Barrier	Torus Water	Cast Austenitic Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-5 Aging Effects Requiring Management for Components Supporting Reactor Core Isolation Cooling System [E51] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/ Activity
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-6 Aging Effects Requiring Management for Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Filter Housing / C.2.2.9.4	Fission Product Barrier Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Piping / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.3	Fission Product Barrier Pressure Boundary	Air	Copper	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.4	Fission Product Barrier Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Rupture Disc / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Thermowell / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Gray Cast Iron	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.3-6 Aging Effects Requiring Management for Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.9.2	Fission Product Barrier Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.3	Fission Product Barrier Pressure Boundary	Air	Copper Alloy	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.3-7 Aging Effects Requiring Management for Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Flex Hose / C.2.2.9.1	Pressure Boundary	Air	Stainless Steel	Cracking	Gas Systems Component Inspections
Nitrogen Tank Jacket / C.2.2.9.1	Structural Support	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.3.1	Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Torus Submerged Components Inspection Program
Piping / C.2.2.3.1	Pressure Boundary	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Torus Submerged Components Inspection Program
Piping / C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Pressure Buildup Coil / C.2.2.8.2	Pressure Boundary Exchange Heat	Dried Gas	Stainless Steel	Cracking	None Required
Rupture Disc / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Storage Tank / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required

Table 3.2.3-7 Aging Effects Requiring Management for Components Supporting Primary Containment Purge and Inerting System [T48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.9.2	Pressure Boundary	Inside	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.3.2	Pressure Boundary	Torus Water	Stainless Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Vaporizer / C.2.2.8.2	Pressure Boundary, Exchange Heat	Dried Gas	Stainless Steel	Cracking	None Required

Table 3.2.3-8 Aging Effects Requiring Management for Components Supporting Post LOCA Hydrogen Recombiner System [T49] Intended Functions and Their Component Functions (Unit 2 only)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

3.2.4 AUXILIARY SYSTEMS

Table 3.2.4-1 Aging Effects Requiring Management for Components Supporting Control Rod Drive System [C11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Accumulator / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Accumulator/ C.2.2.8.1	Pressure Boundary Fission Product Barrier	Dried Gas	Carbon Steel	Cracking	None Required
Bolting / C.2.2.10.1 (Non-Class 1)	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Piping / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.8.2	Pressure Boundary Fission Product Barrier	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.4-1 Aging Effects Requiring Management for Components Supporting Reactivity Control System [C11] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Rupture Disc / C.2.2.8.2	Pressure Boundary Fission Product Barrier	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.2.1	Pressure Boundary Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.2.2	Pressure Boundary Fission Product Barrier	Demin Water	Stainless Steel	Loss of material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.8.3	Pressure Boundary Fission Product Barrier	Dried Gas	Copper Alloy	Cracking	None Required
Valve Bodies / C.2.2.9.1	Pressure Boundary Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking Loss of material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.3	Pressure Boundary Fission Product Barrier	Air	Copper Alloy	Cracking	None Required

Table 3.2.4-2 Aging Effects Requiring Management for Components Supporting Refueling Platform Equipment Assembly [F15] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts C.2.6.3	Structural support Nonsafety Related Structural Support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection
Miscellaneous Steel C.2.6.3	Structural support; Nonsafety Related Structural Support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection
Rivets	Structural Support	Inside	Aluminum	None	None Required
Structural Steel C.2.6.3	Structural support	Inside	Carbon steel	Loss of material	Protective Coatings Program Overhead Crane and Refueling Platform Inspection

Table 3.2.4-3 Aging Effects Requiring Management for Components Supporting the Insulation System [L36] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Aluminum Jacket / C.2.4.4.2	Environmental Control	Outside	Aluminum	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Insulation / C.2.4.4.1	Environmental Control	Outside	Asbestos, Calcium, Silicate, Fiberglass	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Insulation / C.2.4.4.1	Environmental Control	Inside, Outside	Ceramics, Mineral Fiber	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Insulation Bolting / C.2.4.4.2	Environmental Control	Outside	Galvanized Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Insulation Bolting / C.2.4.4.2	Environmental Control	Outside	Stainless Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program
Stainless Steel Jacket / C.2.4.4.2	Environmental Control	Inside	Stainless Steel	Loss of Material Cracking Change in Material Properties	Equipment and Piping Insulation Monitoring Program
Wire for Insulation / C.2.4.4.2	Environmental Control	Outside	Carbon Steel	Loss of Material Cracking	Equipment and Piping Insulation Monitoring Program

Table 3.2.4-4 Aging Effects Requiring Management for Components Supporting Access Doors [L48] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Missile Barrier Fission Product Barrier	Inside, Outside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.2.4-5 Aging Effects Requiring Management for Components Supporting Condensate Transfer and Storage System [P11] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.2	Pressure Boundary	Outside	Stainless Steel	Loss of Preload	Torque Activities
Piping / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Aluminum	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Galvanized Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Tanks / C.2.2.2.3	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material	Demineralized Water and Condensate Storage Tank Chemistry Control Condensate Storage Tank Inspection
Valve Bodies / C.2.2.2.2	Pressure Boundary	Demin Water	Cast Austenitic Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspection

Table 3.2.4-6 Aging Effects Requiring Management for Components Supporting Sampling System [P33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.2	Pressure Boundary Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Outside, Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Flexible Connector / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Piping / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Piping / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Bowl Assembly / C.2.2.6.2	Pressure Boundary	Raw Water	Cast Austenitic Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Discharge Column / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Pump Discharge Head / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Sub Base / C.2.4.1	Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program
Restricting Orifices / C.2.2.6.2	Pressure Boundary, Flow Restriction	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program
Sight Glass Body / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Galvanic Corrosion Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Sight Glass Body/ C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer / C.2.2.6.4	Pressure Boundary	Raw Water	Gray Cast Iron	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer Basket / C.2.2.6.2	Debris Protection	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Strainer Basket / C.2.2.6.4	Debris Protection	Raw Water	Gray Cast Iron	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program

Table 3.2.4-7 Aging Effects Requiring Management for Components Supporting Plant Service Water System [P41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program
Thermowell / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program
Valve Bodies / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.6.2	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Valve Bodies / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Flow Blockage	PSW and RHRSW Chemistry Control Program Structural Monitoring Program
Venturi / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections

Table 3.2.4-8 Aging Effects Requiring Management for Components Supporting Reactor Building Closed Cooling Water System [P42] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Flexible Connectors / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Flow Element / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Heat Exchanger Shells / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Piping / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Relief Valve Base / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Temperature Probe / C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Thermowell / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection
Valve Bodies / C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspection

Table 3.2.4-9 Aging Effects Requiring Management for Components Supporting Instrument Air System [P52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Air Receiver / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Hose / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Regulator Pressure / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Tubing/ C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required

Table 3.2.4-10 Aging Effects Requiring Management for Components Supporting Primary Containment Chilled Water System [P64] Intended Functions and Their Component Functions (Unit 2 Only)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting/ C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Cap/ C.2.2.5.3	Pressure Boundary	Closed Cooling Water	Copper Alloy	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Piping/ C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Thermowell/ C.2.2.5.2	Pressure Boundary	Closed Cooling Water	Stainless Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies/ C.2.2.5.1	Pressure Boundary	Closed Cooling Water	Carbon Steel	Loss of Material Cracking	Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.4-11 Aging Effects Requiring Management for Components Supporting Drywell Pneumatics System [P70] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Inside	Stainless Steel	Loss of Preload	Torque Activities
Filter Housings / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Filter Housings / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Flanges / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Flexible Hoses / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Piping / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Tubing / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required

Table 3.2.4-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Expansion Tank / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Filter housing / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Flex Hose / C.2.2.2.2	Pressure Boundary	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Flexible Connector/ C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Piping / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Piping / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Restricting Orifice/ C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Tanks / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities

Table 3.2.4-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator System [R43] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.2.1	Pressure Boundary	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Valve Bodies / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary	Wetted Gas	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Valve Bodies / C.2.2.9.3	Pressure Boundary	Wetted Gas	Copper Alloy	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-13 Aging Effects Requiring Management for Components Supporting Reactor Building Crane [T31] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Structural Support	Inside	Carbon Steel	Loss of Material	Overhead Crane and Refueling Platform Inspection Protective Coatings Program

Table 3.2.4-14 Aging Effects Requiring Management for Components Supporting Tornado Relief Vent Assemblies [T38] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Screws / C.2.6.3	Structural Support	Inside; Outside	Stainless Steel	None	None Required
Support Frame/ C.2.6.6	Structural Support	Inside; Outside	Aluminum	None	None Required
Tornado Relief Vent Dome/ C.2.6.8	Fission Product Barrier	Inside; Outside	Acrylic (Plexiglas G Cellcast Acrylic Polymer)	Cracking	Structural Monitoring Program

Table 3.2.4-15 Aging Effects Requiring Management for Components Supporting Reactor Building HVAC System [T41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Fission Product Barrier, Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Ductwork / C.2.2.9.4	Fission Product Barrier, Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Flow Element / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking	Gas Systems Component Inspections
Tubing / C.2.2.9.3	Pressure Boundary	Air	Copper Alloy	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.4-16 Aging Effects Requiring Management for Components Supporting Traveling Water Screens / Trash Rack System [W33] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Trash Rack / C.2.6.3	Debris Protection	Submerged	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Traveling Screen / C.2.6.3	Debris Protection	Submerged	Carbon Steel Stainless Steel	Loss of Material	Structural Monitoring Program
Traveling Screen / C.2.6.3	Debris Protection	Submerged	Copper Alloy	None	None Required
Valve Bodies / C.2.2.6.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Flow Blockage Cracking	PSW and RHRSW Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Galvanic Susceptibility Inspections

Table 3.2.4-17 Aging Effects Requiring Management for Components Supporting Outside Structures HVAC System [X41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Bolting / C.2.2.10.2	Pressure Boundary	Outside	Stainless Steel	Loss of Preload	Torque Activities
Duct Sleeve / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Restricting Orifices / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Tubing / C.2.2.9.3	Pressure Boundary	Air	Copper	Loss of Material Cracking	Gas Systems Component Inspections

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Boltings / C.2.2.10.1	Pressure Boundary	Inside Outside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Fire Doors / C.2.3.4.3	Fire Barrier	Inside	Carbon Steel	Loss of Material	Fire Protection Activities
Fire Doors / C.2.3.4.3	Fire Barrier	Inside	Galvanized Steel Copper Alloy Stainless Steel Aluminum Nonmettalic, Inorganic Gypsum Fibers, Nonasbestos Synthetic Nonmetallic, Organic	None	None Required
Fire Hydrants / C.2.3.1	Pressure Boundary	Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Fittings / C.2.3.1	Pressure Boundary	Raw Water Air	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Fittings / C.2.3.3	Pressure Boundary	Air	Copper Alloy Cast Iron	Cracking Loss of Material	Fire Protection Activities
Fusible Material / C.2.3.1	Pressure Boundary	Inside	Nonferrous Metal	Loss of Material Cracking	Fire Protection Activities
Kaowool Hold-Down Straps / C.2.3.4.3	Fire Barrier	Inside	Galvanized Steel	Cracking Change in Material Properties	Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Nozzles / C.2.3.1	Flow Restriction	Air	Copper Alloy	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Nozzles / C.2.3.3	Flow Restriction	Air	Aluminum Copper Alloy	Cracking Loss of Material	Fire Protection Activities
Penetration Seals / C.2.3.4.1	Fire Barrier	Inside; Embedded	Ceramics Carbon Steel Synthetic Fiber Elastomers Concrete	Cracking Change in Material Properties Loss of Material	Fire Protection Activities
Pilot Valves / C.2.3.1	Pressure Boundary	Raw Water	Aluminum	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Pipe Line Strainers / C.2.3.1	Pressure Boundary	Air	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Piping / C.2.3.1	Pressure Boundary	Raw Water Air	Carbon Steel Aluminum Galvanized Steel Copper Alloy Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Piping / C.2.3.2	Pressure Boundary	Fuel Oil	Carbon Steel Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities
Piping / C.2.3.3	Pressure Boundary	Air Carbon Dioxide Dried Gas	Carbon Steel Galvanized Steel	Cracking Loss of Material	Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Pump Casings / C.2.3.1	Pressure Boundary	Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Restricting Orifices / C.2.3.1	Pressure Boundary, Flow Restriction	Raw Water Air	Stainless Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Sprinkler Head Bulbs / C.2.3.1	Pressure Boundary	Inside	Ceramics	Cracking	Fire Protection Activities
Sprinkler Head Links / C.2.3.1	Pressure Boundary	Inside	Copper	Loss of Material Cracking	Fire Protection Activities
Sprinkler Heads / C.2.3.1	Flow Direction, Pressure Boundary, Flow Restriction	Raw Water Air	Stainless Steel Copper Alloy Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Strainer Basket / C.2.3.1	Pressure Boundary	Air Raw Water	Stainless Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Strainers / C.2.3.1	Pressure Boundary	Air Raw Water	Cast Iron	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Tank / C.2.3.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Tank / C.2.3.1	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material Cracking Flow Blockage	Fire Protection Activities Protective Coatings Program
Tank / C.2.3.2	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities

Table 3.2.4-18 Aging Effects Requiring Management for Components Supporting Fire Protection System [X43] Intended Functions and Their Intended Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Tank / C.2.3.3	Pressure Boundary	Carbon Dioxide, Dried Gas	Carbon Steel	Cracking Loss of Material	Fire Protection Activities
Tank Insulation / C.2.3.3	Environmental Control	Inside	Organic	Cracking Change in Material Properties	Fire Protection Activities
Tubing / C.2.3.2	Pressure Boundary	Fuel Oil	Copper Alloy	Loss of Material Cracking	Fire Protection Activities Diesel Fuel Oil Testing
Tubing Fittings / C.2.3.1	Pressure Boundary	Fuel Oil Raw Water	Copper Alloy Cast Iron Copper	Loss of Material Cracking	Fire Protection Activities
Valve Bodies / C.2.3.1	Pressure Boundary	Raw Water Air	Carbon Steel Cast Iron Copper Alloy	Loss of Material Cracking Flow Blockage	Fire Protection Activities
Valves Bodies / C.2.3.2	Pressure Boundary	Fuel Oil	Copper Alloy Cast Iron	Loss of Material Cracking	Diesel Fuel Oil Testing Fire Protection Activities
Valves Bodies / C.2.3.3	Pressure Boundary	Carbon Dioxide Dried Gas Air	Carbon Steel Copper Alloy	Cracking Loss of Material	Fire Protection Activities

Table 3.2.4-19 Aging Effects Requiring Management for Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Discharge Head / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Flex Hose / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Manway Shell / C.2.2.9.1	Shelter/ Protection	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Piping / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Piping / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspection Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Pump / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Strainer Basket / C.2.2.7.2	Shelter/ Protection	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Tank / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Cracking Loss of Material	Diesel Fuel Oil Testing

Table 3.2.4-19 Aging Effects Requiring Management for Components Supporting Fuel Oil System [Y52] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Valve Bodies / C.2.2.7.1	Pressure Boundary	Fuel Oil	Carbon Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Valve Bodies / C.2.2.7.2	Pressure Boundary	Fuel Oil	Stainless Steel	Loss of Material Cracking	Diesel Fuel Oil Testing
Valve Bodies / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Valve Bodies / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

Table 3.2.4-20 Aging Effects Requiring Management for Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Accumulator / C.2.2.9.1 Air Valve	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections
Accumulator Piping / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Accumulator Tanks / C.2.2.8.2	Pressure Boundary	Dried Gas	Stainless Steel	Cracking	None Required
Bolting / C.2.2.10.1	Pressure Boundary	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Duct Gasket / C.2.6.7	Pressure Boundary	Air; Inside	Fibers, Nonasbestos Synthetic; Elastomers, Other	Material Property Changes and Cracking	Passive Component Inspection Activities Gas System Component Inspections
Duct Heater / C.2.2.9.4	Pressure Boundary	Air	Aluminum	Loss of Material	Gas Systems Component Inspections
Duct Silencer / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking	None Required
Ductwork / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Ductwork / C.2.2.9.4	Pressure Boundary	Outside	Galvanized Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Ductwork Flex Connector / C.2.6.7	Pressure Boundary	Air; Inside	Fibers, Non-Asbestos Synthetic; Elastomers, Other	Material Property Changes and Cracking	Passive Component Inspections Activities Gas Systems Component Inspections
Filter Housing / C.2.2.9.4	Pressure Boundary	Air	Galvanized Steel	Cracking	None Required

Table 3.2.4-20 Aging Effects Requiring Management for Components Supporting Control Building HVAC System [Z41] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Instrument Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Instrument Piping / C.2.2.9.3	Pressure Boundary	Air	Copper Alloy	Loss of Material Cracking	Gas Systems Component Inspections
Louver / C.2.2.9.1	Pressure Boundary	Outside	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Piping / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Radiation Element / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Restricting Orifice / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections
Thermowell / C.2.2.9.2	Pressure Boundary	Inside	Stainless Steel	Cracking	None Required
Tubing / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper	Cracking	None Required
Valve Bodies / C.2.2.8.1	Pressure Boundary	Dried Gas	Carbon Steel	Cracking	None Required
Valve Bodies / C.2.2.8.3	Pressure Boundary	Dried Gas	Copper Alloy	Cracking	None Required
Valve Bodies / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking Loss of Material	Gas Systems Component Inspections

3.2.5 STEAM AND POWER CONVERSION

Table 3.2.5-1 Aging Effects Requiring Management for Components Supporting Electro-Hydraulic Control System [N32] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Piping / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

Table 3.2.5-2 Aging Effects Requiring Management for Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting / C.2.2.10.1	Pressure Boundary Fission Product Barrier	Inside	Carbon Steel	Loss of Preload Loss of Material	Torque Activities Protective Coatings Program
Condenser Shell / C.2.2.1.1	Fission Product Barrier Pressure Boundary	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Piping / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Piping / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Preheater / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Preheater / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Restricting Orifices/ C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Strainer / C.2.2.1.1	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections

Table 3.2.5-2 Aging Effects Requiring Management for Components Supporting Main Condenser System [N61] Intended Functions and Their Component Functions (Continued)

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Thermowell / C.2.2.1.2	Pressure Boundary Fission Product Barrier	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.1	Pressure Boundary	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chemistry Control Flow Accelerated Corrosion Program Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections
Valve Bodies / C.2.2.1.2	Pressure Boundary	Reactor Water	Stainless Steel	Loss of Material Cracking	Reactor Water Chemistry Control Treated Water Systems Piping Inspections

3.3 CIVIL/STRUCTURAL

The following tables provide the civil/structural component types that are subject to an aging management review.

3.3.1 CIVIL/STRUCTURAL COMPONENTS

Table 3.3.1-1 Aging Effects Requiring Management for Components Supporting Piping Specialties [L35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Hangers and Supports for ASME Class I Piping / C.2.6.4	Structural Support	Containment Atmosphere; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Hangers and Supports for ASME Class I Piping / C.2.6.4	Structural Support	Containment Atmosphere; Inside	Stainless Steel	None	None Required
Hangers and Supports for Non ASME Class I Piping, Tubing, and Ducts / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside; Outside; Submerged	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Tube Trays and Covers / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Stainless Steel	None	None Required

Table 3.3.1-2 Aging Effects Requiring Management for Components Supporting Cable Trays and Supports [R33] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Cable Trays and supports / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Cable Trays and supports / C.2.6.4	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Inside	Aluminum	None	None Required

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.2	Structural Support; Nonsafety Related Structural Support	Containment Atmosphere; Embedded; Inside Torus Water	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Suppression Pool Chemistry Control
Blind Flange* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control
Containment Isolation Valves* / C.2.2.2.2	Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.3.1	Fission Product Barrier	Demin Water	Carbon Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Containment Isolation Valves* / C.2.2.6.2	Fission Product Barrier	Raw Water	Carbon Steel	Loss of Material Cracking	Passive Component Inspection Activities
Containment Isolation Valves* / C.2.2.9.1	Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Containment Isolation Valves* / C.2.2.9.2	Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspection
Containment Penetrations (Mechanical only) / C.2.6.2	Fission Product Barrier	Containment Atmosphere; Embedded; Inside	Carbon Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions (Continued)

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Miscellaneous Steel / C.2.6.2	Structural Support; Radiation Shielding; Pipe Whip Restraint; Nonsafety Related Structural Support	Containment Atmosphere; Embedded; Inside; High Humidity; Torus Water	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Suppression Pool Chemistry Control
Piping* / C.2.2.2.2	Fission Product Barrier	Demin Water	Stainless Steel	Loss of Material Cracking	Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections
Piping* / C.2.2.3.1	Fission Product Barrier	Torus Water	Carbon Steel	Loss of Material Cracking	Suppression Pool Chemistry Control Treated Water Systems Piping Inspections
Piping* / C.2.6.2	Fission Product Barrier	Raw Water	Carbon Steel	Loss of Material Cracking	Passive Component Inspection Activities
Piping* / C.2.2.9.1	Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Piping* / C.2.2.9.2	Fission Product Barrier	Wetted Gas	Stainless Steel	Loss of Material	Gas Systems Component Inspection
Reinforced Concrete / C.2.6.1	Structural Support; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding	Inside; Containment Atmosphere	Concrete Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Steel Bellows (Inside Vent Pipe) C.2.6.2	Pressure Boundary; Fission Product Barrier	Containment Atmosphere; Inside	Carbon Steel Stainless Steel	Loss of Material	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program

Table 3.3.1-3 Aging Effects Requiring Management for Components Supporting Primary Containment [T23] Intended Functions and Their Component Functions (Continued)

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel / C.2.6.2	Structural Support; Shelter/Protection; Pressure Boundary; Radiation Shielding; Nonsafety Related Structural Support; HE/ME Shielding; Missile Barrier; Pipe Whip Restraint; Fission Product Barrier; Exchange Heat	Containment Atmosphere; Inside; Torus Water; Embedded	Carbon Steel Stainless Steel	Loss of Material Cracking	Protective Coatings Program Primary Containment Leakage Rate Testing Program Inservice Inspection Program Suppression Pool Chemistry Control Component Cyclic or Transient Limit Program
Tubing* / C.2.2.9.2	Fission Product Barrier; Pressure Boundary	Wetted Gas	Stainless Steel	Loss of Material Cracking	Gas Systems Component Inspections
Vent Pipe, Vent Header, Downcomers / C.2.6.2	Pressure Boundary Fission Product Barrier	Containment Atmosphere; High Humidity; Inside; Torus Water	Carbon Steel	Loss of Material Cracking	Protective Coatings Program Inservice Inspection Program Primary Containment Leakage Rate Testing Program Component Cyclic or Transient Limit Program Suppression Pool Chemistry Control

* Piping and valve bodies include components from systems P51, P21, T23, G51, G11, D11, and C51. These are all included in function T23-01, Torus/Drywell.

Table 3.3.1-4 Aging Effects Requiring Management for Components Supporting Fuel Storage [T24] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Anchors and Bolts / C.2.6.5	Structural Support	Inside; Demin Water; Embedded	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Miscellaneous Steel / C.2.6.3	Structural Support ; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel / C.2.6.5	Fission Product Barrier	Demin Water ; Embedded; Inside	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Reinforced Concrete / C.2.6.1	Structural Support; Shelter/Protection	Inside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete / C.2.6.1	Structural Support; Nonsafety Related Structural Support	Inside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Seismic restraints for spent fuel storage racks / C.2.6.6	Structural Support	Inside; Demin Water	Aluminum	Loss of Material	Fuel Pool Chemistry Control
Storage Racks/ C.2.6.6	Structural Support; Nonsafety Related Structural Support	Inside	Aluminum	None	None Required
Structural Steel / C.2.6.5	Structural Support; Shelter/Protection; Fission Product Barrier	Demin Water; Inside	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control

Table 3.3.1-5 Aging Effects Requiring Management for Components Supporting Reactor Building [T29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Blowout Panels / C.2.6.6	Structural Support; Fission Product Barrier	Inside	Aluminum	None	None Required
Miscellaneous Steel / C.2.6.3	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel / C.2.6.3	Structural Support; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Stainless Steel	None	None Required
Panel Joint Seals and Sealants / C.2.6.7	Shelter/Protection; Fission Product Barrier	Inside; Outside	Elastomers; Nonmetallic, Inorganic	Material Property Changes and Cracking Loss of Adhesion	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete C.2.6.1	Structural Support; Fire Barrier; Shelter/Protection; Flood Barrier; Fission Product Barrier; Radiation Shielding; Missile Barrier; HE/ME Shielding; Nonsafety Related Structural Support	Inside; Outside	Concrete Masonry Block Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel C.2.6.3	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Inside; Outside; Submerged	Carbon Steel Galvanized Steel Stainless Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-6 Aging Effects Requiring Management for Components Supporting Drywell Penetrations [T52] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.2	Fission Product Barrier	Containment Atmosphere; Embedded; Inside	Carbon Steel	Loss of Material	Protective Coatings Program Primary Containment Leakage Rate Testing Program Inservice Inspection Program

Table 3.3.1-7 Aging Effects Requiring Management for Components Supporting Reactor Building Penetrations [T54] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Structural Steel/ C.2.6.3	Fission Product Barrier	Embedded; Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

Table 3.3.1-8 Aging Effects Requiring Management for Components Supporting Turbine Building [U29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside; Wetting Other Than Humidity	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Radiation Shielding; Nonsafety Related Structural Support	Buried; Inside; Outside	Concrete Masonry Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-9 Aging Effects Requiring Management for Components Supporting Intake Structure [W35] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside; High Humidity; Wetting Other Than Humidity	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel C.2.6.3	Structural Support; Missile Barrier; Nonsafety Related Structural Support	Embedded; High Humidity; Inside; Outside; Wetting Other Than Humidity; Submerged	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete C.2.6.1	Structural Support; Shelter/Protection; Flood Barrier; Missile Barrier; Nonsafety Related Structural Support	Buried; Submerged; Inside; Outside; High Humidity; Wetting Other Than Humidity	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel C.2.6.3	Structural Support; Shelter/Protection; Missile Barrier; Flow Direction; Nonsafety Related Structural Support	Embedded; Outside; Inside; High Humidity; Wetting Other Than Humidity	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-10 Aging Effects Requiring Management for Components Supporting Yard Structures [Y29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Cover Plates – Pull Boxes/ C.2.6.6	Shelter/Protection; Flood Barrier	Inside; Outside	Aluminum	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Nonsafety Related Structural Support	Inside; Outside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside; Outside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-11 Aging Effects Requiring Management for Components Supporting Main Stack [Y32] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Outside	Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside; Outside	Stainless Steel; Copper Alloy (Bronze)	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Outside	Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Galvanized Steel	None	None Required
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Fission Product Barrier; Nonsafety Related Structural Support; Radiation Shielding	Inside; Outside	Concrete Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel / C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Galvanized Steel	None	None Required

Table 3.3.1-12 Aging Effects Requiring Management for Components Supporting Emergency Diesel Generator Building [Y39] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Missile Barrier	Inside; Outside	Concrete Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

Table 3.3.1-13 Aging Effects Requiring Management for Components Supporting Control Building [Z29] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program
Blowout Panels / C.2.6.6	Structural Support; Fission Product Barrier	Inside	Aluminum	None	None Required
Miscellaneous Steel/ C.2.6.3	Structural Support; Nonsafety Related Structural Support	Embedded; Inside	Carbon Steel Galvanized Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program
Reinforced Concrete/ C.2.6.1	Structural Support; Shelter/Protection; Nonsafety Related Structural Support; Missile Barrier	Inside / Outside	Concrete Carbon Steel	Loss of Material Cracking	Structural Monitoring Program Protective Coatings Program
Structural Steel/ C.2.6.3	Structural Support; Shelter/Protection; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Structural Monitoring Program Protective Coatings Program

3.4 ELECTRICAL

The following tables provide the electrical component types which are subject to an aging management review. These component types are not associated with one particular system, but could be used in any in-scope system, and are evaluated on a plant-wide basis for the determination of aging effects requiring management. The determination of aging effects requiring management is presented in section C.1.3. Electrical penetrations meet the criteria for components which require an aging management review; however, these components are covered under a TLAA which is discussed in section 4.

3.4.1 ELECTRICAL COMPONENTS

Table 3.4.1-1 Aging Effects Requiring Management for Electrical Components (Plant-Wide)

Electrical Component	Component Function	Environment	Material	Aging Effects	Aging Management Program/Activity
Cable (Outside Containment) / C.2.5.4	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Submerged; Inside: Outside	Various Polymers Tinned and Bare Copper	Change in Insulation Resistance	Wetted Cable Activities
Cable (Inside Containment) / C.2.5.5	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Tinned and Bare Copper	None	None
Electrical Connectors Splices, Terminal Blocks / C.2.5.3	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside/Outside	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper	None	None
Electrical Penetration Assemblies (Section 4, Figure 4.4-5)	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Painted Steel Stainless Steel	None	None Penetration assemblies are covered by an EQ TLAA.

Table 3.4.1-1 Aging Effects Requiring Management for Electrical Components (Plant-Wide) (Continued)

Electrical Component	Component Function	Environment	Material	Aging Effects	Aging Management Program/Activity
Phase Bussing/ C.2.5.1	Provide insulation resistance to preclude shorts, grounds, and unacceptable leakage currents	Inside	Various Polymers Galvanized and Stainless Steel Tinned and Bare Copper	None	None
Nelson Frames/ C.2.5.2	Fission Product Barrier Fire Protection	Inside	Various Polymers Galvanized and Painted Steel	None	None

Table 3.4.1-2 Aging Effects Requiring Management for Components Supporting Electrical Panels, Racks & Cabinets [H11] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Electrical panels, racks and cabinets/ C.2.6.4	Structural Support; Shelter/Protection Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

Table 3.4.1-3 Aging Effects Requiring Management for Components Supporting Instrument Racks, Panels, & Enclosures [H21] Intended Functions and Their Component Functions

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Instrument racks, panels and enclosures/ C.2.6.4	Structural Support; Nonsafety Related Structural Support	Inside	Carbon Steel	Loss of Material	Protective Coatings Program Structural Monitoring Program

Section 4

TIME-LIMITED AGING ANALYSES

CONTENTS

4.1 INTRODUCTION

Southern Nuclear has performed a detailed review of design analyses and calculations for Plant Hatch, pursuant to 10 CFR 54.21(c)(1), to determine which analyses meet the criteria of 10 CFR 54.3. Analyses and calculations that meet the criteria of 10 CFR 54.3 contain time-limited or age related assumptions. The review included analyses performed by Southern Company, the architect engineer, and the nuclear steam supply system vendor. Independently, Southern Nuclear performed a review of the Current Licensing Basis (CLB) for time-limited or age-related statements that met the criteria or 10 CFR 54.3. These two separate reviews provided assurance that analyses meeting the rule requirements would be properly identified and dispositioned. The review yielded analyses in several categories, summarized in Table 4.1.1-1.

4.1.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES

Time-Limited Aging Analyses (TLAAs) are defined in 10 CFR 54.3 as analyses that meet six criteria. The regulation, as quoted below, requires the licensee to provide an evaluation of the analyses that meet all of the criteria.

Time-limited aging analyses are those licensee calculations and analyses that:

- Involve systems, structures, and components within the scope of license renewal, as delineated in Section 54.4(a);
- Consider the effects of aging;
- Involve time-limited assumptions defined by the current operating term, for example, 40 years;
- Were determined to be relevant by the licensee in making a safety determination;
- Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in Section 54.4(b); and
- Are contained or incorporated by reference in the CLB.

10 CFR 54.21(c) requires licensees to include a list of time-limited aging analyses in the application. The licensee must demonstrate that either:

- the analyses remain valid for the extended license term;
- the analyses have been acceptably projected to the end of the extended term; or
- programs manage the effects of aging associated with the analyses.

This section addresses the analyses that were reviewed by Southern Nuclear and the issues discovered in the process. For those analyses that did meet the six criteria listed above, this section presents a detailed discussion of the analyses.

4.1.1.1 Procedure

Southern Nuclear created a procedure to evaluate specific analyses for the six TLAA criteria. The review focused on those calculations performed by Bechtel Power Corporation (the previous architect engineer), the Southern Company Services, Inc., (SCS) Engineering organization (the current architect engineer), and the General Electric Company (GE) for the Nuclear Steam Supply System equipment scope.

To identify the scope of calculations to review, Southern Nuclear compiled a complete list from the Plant Hatch Design Record Management System for Bechtel and SCS calculations. General Electric was contracted to identify possible TLAAs for specific systems and components within GE's scope of supply. However, Southern Nuclear principally relied upon the CLB review to identify the TLAAs in GE's scope. Southern Nuclear focused the review of its calculations on the time-limited nature of TLAAs. Calculations were first screened for Criterion 3 with specific emphasis on assumptions or design elements related to the current operating term of 40 years.

The second step was to evaluate the remaining analyses for the other five criteria, beginning with a determination of whether the calculation addressed the design of systems, structures, and components that were in the scope of license renewal. Both active and passive components were addressed in the review for TLAAs.

4.1.1.2 Identification of Exemptions

The License Renewal Rule requires a list be provided of "plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation."

This list has been compiled through a search of docketed correspondence, the operating licenses, and the FSAR. All exemptions in effect were identified and listed and Bechtel SERCH was used, as well as in-house databases. Each exemption in effect was then evaluated to determine if it involved a TLAA as defined in 10 CFR 54.3.

Evaluation of the exemptions in effect for Plant Hatch revealed that one item was similar to an exemption request containing a TLAA that will need to be updated for license renewal. However, this item is not a 10 CFR 50.12 exemption. Rather, this item is a technical alternative (as defined in 10 CFR 50.55a(a)(3)(i)) to the requirements to inspect circumferential welds on the reactor pressure vessel. The relief request is described in the letter dated December 2, 1998, from H. L. Sumner to the NRC document control desk (Ref. 1). This TLAA and its demonstration are discussed in greater detail in section 4.6.3 of this application.

Table 4.1.1-1 Time-Limited Aging Analyses

Time-Limited Aging Analyses
1. Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.2.
2. Fatigue/stress analyses for the torus structure and nozzle connections. The results of the evaluation for 60 years of operation are provided in section 4.2.
3. Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.3.
4. Calculation of the corrosion allowance assumed for the reactor vessel. The results of the evaluation for 60 years of operation are provided in section 4.3.
5. Environmental equipment qualification calculations that qualify electrical components for 40 years. The results of the evaluation for 60 years of operation are provided in section 4.4.
6. A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant. The results of the evaluation for 60 years of operation are provided in section 4.5.
7. Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR 50 Appendix G). The results of the evaluation for 60 years of operation are provided in section 4.6.
8. Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR 50 Appendix G) due to the extended operating term. The results of the evaluation for 60 years of operation are provided in section 4.6.
9. Analyses performed to demonstrate the acceptability of a technical alternative to the Code requirement for inspection of reactor pressure vessel circumferential welds. The results of the evaluation for 60 years of operation are provided in section 4.6.
10. Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the Plant Hatch FSAR. The results of the evaluation for 60 years of operation are provided in section 4.7.

4.2 PIPE STRESS TIME-LIMITED AGING ANALYSES

Thermal fatigue is addressed in the majority of the pipe stress analyses that Southern Nuclear reviewed. The welds between the components and the piping were addressed in the piping analyses; therefore, this section focuses on the piping stress analyses treatment of thermal fatigue. The treatment of thermal fatigue is different, depending on the code requirements for Class 1 and Non-Class 1 piping. Therefore, the two types of piping will be discussed separately. Non-Class 1 components include ASME Section III Classes 2 and 3, B31.7 Classes 2 and 3, and B31.1, power piping and tubing.

4.2.1 CURRENT LICENSING BASES FOR FATIGUE CYCLES AT PLANT HATCH

For both Class 1 and Non-Class 1 analyses, Southern Nuclear reviewed the Bechtel and SCS calculations for assumptions pertaining to the number of thermal cycles. For Class 1 analyses, the Code requires a detailed treatment of the number of thermal cycles the piping will experience. The Plant Hatch Unit 1 FSAR, section A.3, and Plant Hatch Unit 2 FSAR, section 3.9, provide a listing of the number of thermal transients Class 1 piping is assumed to experience over the current license term. The Plant Hatch Unit 2 FSAR also contains statements in sections 3.9 and 6.3 (Ref. 2&3) that address the number of thermal cycles that the Class 2 and 3 piping will experience. The Unit 2 FSAR states that these systems will have fewer than 7,000 thermal cycles over the current license term. Since the calculation method for pipe stress analysis is the same for Non-Class 1 piping on both units, the thermal cycle assumption applies to both units.

The fatigue evaluation for Non-Class 1 piping and tubing was not explicitly performed but is accounted for by the stress range reduction factor, *f*, for cyclic conditions. The design codes provide the values of *f* based on the number of equivalent full-temperature cycles. Therefore, the assumed number (7,000) is important because it allows a stress range reduction factor of 1.0 to be used in the allowable stress equations for piping analysis. This assumption is carried over to the nonsafety-related piping for both units because the analysis method is the same. Therefore, a time-limited, age-related assumption is inherent in the piping analyses.

4.2.2 EVALUATION OF CLASS 1 COMPONENTS

SCS, Bechtel, GE, and various subcontractors performed Class 1 component stress analyses for Plant Hatch. SCS reviewed these analyses and identified TLAAs from the stress reports along with relevant time-dependent calculations.

The ASME Code Editions of record for Class 1 component design for Plant Hatch are detailed in <u>Table 4.2.2-1</u>.

The applicable codes identified in Table 4.2.2-1 require an evaluation of the predicted fatigue cumulative usage factor (CUF) for the Class 1 components. The calculation of the predicted CUF includes inherent assumptions as to the number of transient events over the original 40-year license term. The ASME Code requires that the Class 1 components have an initial design predicted CUF less than or equal to 1.0. Therefore, when the extended license term is considered, NRC requires that Class 1 component locations with a predicted CUF of greater than 1.0 require special consideration.

For Plant Hatch, the CUF carries further importance in that Southern Nuclear also used the predicted CUF as a screening criterion to establish locations to be monitored, inspection locations, and the locations of assumed pipe breaks for accident analysis. Southern Nuclear has followed the guidance of NRC Branch Technical Position MEB 3-1, as expressed in Regulatory Guide 1.46 (Ref. 4), with respect to determining break locations for accident analysis.

Because of explicit commitment to Branch Technical Position MEB 3-1 in the Plant Hatch licensing basis, Southern Nuclear has considered the CUF ≤ 0.1 criterion, and will continue to consider the criterion, when stress calculations are revised as a result of plant design modifications or changes in operating parameters. Because the criterion represents a screening rather than a design constraint, there is no time-limited aspect to the criterion. Thus, it does not represent a time limited aging analysis as used in license renewal.

Southern Nuclear has addressed the Class 1 fatigue TLAAs through an aging management program {demonstration of Criterion (iii) of 10 CFR 54.21 (c) (1)}. This program monitors the CUF of specific bounding locations for Class 1 components at Plant Hatch. The CUF-monitoring program is a complement to other aging management program elements, such as the inservice inspection program. The CUF-monitoring program was implemented in two phases.

The first phase, developed by GE in 1985, included limiting locations in the reactor pressure vessel (RPV). As a result of this phase of the program, Plant Hatch monitors CUF for four components in the RPV. These components are the RPV closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles. These components are monitored for both units (References 5 & 6). The decision criteria for selecting the RPV locations were based on the highest calculated CUFs from the design basis (e.g., fatigue-sensitive locations).

For the second phase of the CUF monitoring program, Southern Nuclear expanded the CUF monitoring program to include Class 1 piping. Conservative equations (Ref. 7) were developed into which actual plant transient counts could be input to estimate the CUF. The equations were developed to monitor the CUF for the limiting locations in each Class 1 piping system where the 40-year predicted CUF exceeded 0.1 in the original analysis. The choice of the 0.1 CUF decision criterion was not related to the MEB 3-1 commitment. This decision value includes sufficient margin, together with explicit fatigue design conservatisms, to account for potential reactor water environmental effects in the selection process.

Much of the conservatism in the design basis calculational process is due to design basis transient definitions. The equations for both the RPV and the Class 1 piping locations are conservatively based on such transient definitions. Based on the several EPRI license renewal fatigue studies, Southern Nuclear concludes that the fatigue impact of conservative design basis transient definitions by themselves overwhelms any potential impact of reactor water environmental effects. Therefore, the use of design basis transient severity in the CUF equations is another conservatism that more than compensates for potential reactor water environmental effects.

Based on the decision criteria and the conservative formulae, the effects of the reactor water environment have been adequately incorporated into the Plant Hatch fatigue management program. Therefore, the "thermal fatigue" aging mechanism identified throughout this application is considered to also encompass any relevant reactor water environmental effects (GSI 190 – Fatigue Evaluation of Metal Components for 60 years).

The equations for the RPV locations have been used to provide current CUF estimates for the past 15 years. To develop a baseline for the Class 1 piping locations, Southern Nuclear evaluated the current CUF based upon actual operating history for both Hatch units to date. The actual operating history was used to project a 60-year CUF for each monitored location. All monitored locations are projected to have a CUF less than 1.0 after 60 years of operation. Southern Nuclear will use the GE-developed equations to continue to monitor CUF for the RPV locations. Southern Nuclear will also use the newer equations to monitor CUF for the Class 1 piping locations. These Class 1 piping locations are as follows:

- Unit 1 RPV equalizer piping;
- Unit 1 core spray piping (for replaced piping outside of the reactor vessel);
- Unit 1 standby liquid control piping;
- Unit 1 feedwater, high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), reactor water cleanup (RWCU) system piping;
- Unit 1 main steam piping (loop B);
- Unit 2 main steam piping (loop D);
- Unit 2 residual heat removal (RHR) suction piping;
- Unit 2 feedwater piping; and
- Unit 2 steam condensate drainage piping.

Based upon the conclusions of the analysis, Southern Nuclear has expanded the fatigue-monitoring program to include these additional Class 1 locations (see "Component Cyclic or Transient Limit Program," appendix A.1.12). Specific events and significant temperature changes will be recorded throughout the remaining current term and through the extended license term. The CUF equations will be updated, and the CUF tracked to measure the CUF against an acceptance criteria of less than or equal to 1.0. In this way, Southern Nuclear manages the TLAA by an Aging Management Program {demonstration of Criterion (iii) of 10 CFR 54.21(c)(1)}.

Table 4.2.2-1 ASME Codes Applicable for Class 1 Piping

Unit	Design Code	Year
1	B31.7, CLASS 1	1969
2	SECTION III, NB	1971

4.2.3 EVALUATION OF TIME-LIMITED AGING ANALYSES FOR NON-CLASS 1 PIPING

The subject components of this review are Non-Class 1 piping components. Non-Class 1 components include ASME Section III Classes 2 and 3, B31.7 Classes 2 and 3, and B31.1 power piping and tubing. This review treats the tubing and other piping components, such as fittings, etc., as piping components because of their pressure boundary function. That is, unless otherwise stated, the use of the term "piping" in the following discussion collectively applies to piping, tubing, and other piping components.

After identification, the TLAAs were evaluated to provide assurance that the piping components addressed by these analyses could perform their intended function(s) during the period of their extended operation of 60 years.

Plant Hatch Non-Class 1 piping was originally designed to the requirements of the ASME Code(s) identified in Table 4.2.3-1 as applicable to the system being analyzed.

To evaluate the effects of cumulative fatigue damage, the total number of full temperature thermal cycles of Hatch Non-Class 1 piping and tubing systems were evaluated using highly conservative assumptions. The thermal events and the associated number of cycles were established from a review of the FSAR, operations manual, and operating history. It was estimated that the Non-Class 1 piping and tubing systems would encounter substantially less than the current design basis of 7,000 and 14,000 cycles, respectively, during 60 years of operation. The basis of the stress reduction factors used for the piping and tubing systems in the original design is, therefore, not affected by operating the plant in the extended operating period of 60 years. Hence, for license renewal, the subject TLAAs, which address thermal fatigue, remain valid for the period of extended operation {demonstration of Criterion (i) of 10 CFR 54.21 (c) (1)}. Table 4.2.3-2 lists the aging management reviews described in appendix C that utilize this TLAA.

Table 4.2.3-1 ASME Codes Applicable to Non-Class 1 Piping

Unit	Design Code	Year
1	B31.1	1967
1	B31.7 CLASS 2, 3	1969
2	SECTION III, NC, ND	1971 through 1971 Addenda
2	B31.1	1967 through 1971 Addenda

Table 4.2.3-2 Aging Management Reviews that Utilize the Thermal Fatigue TLAA

Section Number	Components Reviewed
C.2.2.1.1	Carbon Steel Components in Reactor Water Environments
C.2.2.1.2	Stainless Steel Components in Reactor Water Environments
C.2.2.2.1	Carbon Steel Components in Demineralized Water Environments
C.2.2.2.2	Stainless Steel Components in Demineralized Water Environments
C.2.2.2.3	Condensate Storage Tanks and Components in Demineralized Water Environment
C.2.2.3.1	Carbon Steel Components in Suppression Pool Water Environments
C.2.2.3.2	Stainless Steel Components in Suppression Pool Water Environments
C.2.2.4.1	Carbon Steel Components in Borated Water Environments
C.2.2.4.2	Stainless Steel Components in Borated Water Environments
C.2.2.5.1	Carbon Steel Components in Closed Cooling Water Environments
C.2.2.5.2	Stainless Steel Components in Closed Cooling Water Environments
C.2.2.5.3	Copper Components in Closed Cooling Water Environments
C.2.2.6.1	Carbon Steel Components in River Water Environments
C.2.2.6.2	Stainless Steel Components in River Water Environments
C.2.2.6.3	Copper Components in River Water Environments
C.2.2.6.4	Gray Cast Iron Components in River Water Environments
C.2.2.7.1	Carbon Steel Components in Fuel Oil Environments
C.2.2.7.2	Stainless Steel Components in Fuel Oil Environments
C.2.2.8.1	Carbon Steel Components in Dry Compressed Gas Environments
C.2.2.8.2	Stainless Steel Components in Dry Compressed Gas Environments
C.2.2.8.3	Copper Components in Dry Compressed Gas Environments
C.2.2.9.1	Carbon Steel Components in Humid and Wetted Gas Environments
C.2.2.9.2	Stainless Steel Components in Humid and Wetted Gas Environments
C.2.2.9.3	Copper Components in Humid and Wetted Gas Environments
C.2.2.9.4	Galvanized Steel in Humid and Wetted Gas Environments
C.2.3.1	Water Based Fire Suppression System Components
C.2.3.2	Diesel Fuel Oil Supply System Components
C.2.3.3	Compressed Gas Based Fire Suppression System Components
C.2.3.4.1	Carbon Steel Penetration Sleeves in Fire Barriers

4.2.4 EVALUATION OF THE TORUS

The calculation review for TLAAs identified several calculations that met the six criteria and that addressed fatigue (both dynamic and thermal) of the torus structure. Southern Nuclear reviewed these calculations and determined that a new analysis was necessary to address fatigue in the torus for the extended license term. The analysis (Ref. 8) required an extensive and detailed review of pressure and thermal transients for the torus. Plant operating records and the Plant Unique Analysis Reports, prepared for the Mark I Containment Long Term Program, were consulted in the review. From the review, Southern Nuclear determined that the critical event leading to fatigue of the torus was the lifting of one or more main steam system safety relief valves (SRV).

The analysis concluded that the CUF could be monitored by tracking the number of SRV lifts. The analysis developed formulae for calculating the CUF at any given time during the current and extended license terms based upon the number of SRV lifts. Southern Nuclear has chosen to manage the fatigue of the torus by tracking the SRV lifts and evaluating the fatigue usage for the torus during the current and extended license term {demonstration through Criterion (iii) of 10 CFR 54.21(c)(i)}. This aging management program, "Component Cyclic or Transient Limit Program," is discussed in appendix A.1.12.

4.3 CORROSION ALLOWANCE

An allowance for corrosion was made in determining the appropriate thickness for pressure retaining components in the design of Plant Hatch. Only those analyses containing an assumption of a corrosion allowance that also tied the allowance to a 40-year operating life meet 10 CFR 54.3 Criterion 3. In the review of the Plant Hatch analyses, two scopes of supply are important; the equipment designed and supplied by Bechtel and the equipment designed and supplied by GE.

4.3.1 BECHTEL POWER CORPORATION SCOPE OF SUPPLY

The assumption of a corrosion allowance appears in calculations that confirm pressure rating of piping and components. The piping specifications for both units of Plant Hatch specify corrosion allowances for types of piping based upon material and environment. In most of the calculations reviewed, the corrosion allowance assumed was not tied to a 40-year life of the component. Additionally, corrosion rates were not identified (with specific exceptions discussed). Many of the calculations used standard values from Table A104.2 of ASME B31.1. Once a required minimum wall thickness was calculated, the design often chose the next thicker component size (e.g., the next higher pipe schedule). For these reasons, calculations covering components in the Bechtel scope of supply generally do not meet the definition of a TLAA.

There is a subset of analyses that are the exception to the above paragraph. In the course of evaluating the residual heat removal service water system piping and the plant service water system piping in accordance with Nuclear Regulatory Commission (NRC) Generic Letters 89-13 and 90-05 (References 9 & 10), Bechtel performed calculations to develop evaluation levels for measurements on the piping. These levels were in part based upon the expected thickness of a pipe and upon the predicted wear of that pipe for the remaining service life. In these analyses, the corrosion allowance from the pipe specification was assumed to be the maximum allowed for the 40-year service life of the piping. The corrosion rate thus defined is used in the calculations to predict the expected pipe thickness and to develop the minimum acceptable as-found thickness of the pipe.

These calculations were instrumental in developing the inspection program for the residual heat removal and primary service water piping, much of which is in-scope for license renewal. The formulae used in the calculations have been retained in the inspection program procedure used at Plant Hatch.

The Plant Service Water and RHR Service Water Piping Inspection Program (A.1.13) uses one of two corrosion rates to predict the minimum acceptable measured pipe wall thickness. The first rate is defined by dividing the specified corrosion allowance by 40 years. The second rate is an observed corrosion rate based upon several measurements of the pipe wall. The greater of the two corrosion rates is used to predict the acceptable minimum wall thickness. The action levels of the procedure are also based, in part, on the corrosion rate determined by the corrosion allowance.

The impact of an extended operating period on the inspection program is minimal. A change to the specification-based corrosion rate would not be conservative and is not necessary. Decreasing the corrosion rate (by dividing the current allowance by 60 rather than 40 years) is not appropriate, because a rate thus calculated would not be conservative for the purposes of establishing screening levels for the piping. Therefore, the calculations are conservative for the extended term and do not require revision.

The Plant Service and RHR Service Water Inspection Program will continue to manage the effects of aging (corrosion) for the extended license term {demonstration through Criteria (i) and (iii) of 10 CFR 54.21 (c) (i)}.

4.3.2 GENERAL ELECTRIC SCOPE OF SUPPLY

In reviewing the documents within the design records database, Southern Nuclear found no GE calculation or analysis that explicitly defined the corrosion allowance as a function of 40 years. Therefore, Southern Nuclear contracted GE to make a further determination within their scope of supply. The GE review developed the following conclusions about the Hatch 1 and 2 stainless steel components, general piping, and the reactor vessel.

For austenitic stainless steel components in the Plant Hatch reactor system, the corrosion allowance was not explicitly calculated using a 40-year assumption. The corrosion rate for stainless steel under BWR conditions is very low, and the corrosion allowance will be adequate through the end of the renewal term.

With respect to the reactor vessel, GE reviewed its internal communications, reports, and open literature to determine the method for calculating the Hatch Units 1 and 2 corrosion allowance. The GE review determined (Ref. 21) that a time-dependent corrosion rate was used and that the corrosion allowance was based upon a 40-year assumption for the service life of the vessel. Since this corrosion allowance was determined to meet all six criteria, the corrosion allowance is a TLAA. GE has evaluated the corrosion allowance for the vessel and has determined that the allowance is adequate for operation through the end of the renewed license term {demonstration through Criterion (ii) of 10 CFR 54.21 (c) (i)}.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

Among the most obvious time-limited aging analyses (TLAAs) are those used in existing aging management programs. One such aging management program is the Hatch EQ Program, in which Class 1E safety-related components are qualified in accordance with the requirements of 10 CFR 50.49.

Southern Nuclear has conducted an initial assessment of the Hatch EQ Program to determine which of the analyses in the program meet the definition of a TLAA. The assessment includes evaluations of the EQ analyses to determine if the components qualified could be extended to 60 years. Southern Nuclear is in the process of updating the actual analyses to reflect these assessments.

Section 4.4 discusses the process Southern Nuclear used to identify the TLAAs within the EQ Program for Plant Hatch and then gives a detailed discussion of the EQ Program. In the discussion of the EQ Program for Plant Hatch, it is important to note that Southern Nuclear has prepared qualification data packages (QDPs) to demonstrate that the equipment defined by 10 CFR 50.49(b) is qualified for service in the normal operating environments and accident environments specified for Units 1 and 2. The QDPs are organized in an EQ Central File.

The organization of section 4.4 is as follows:

Process for Identifying EQ TLAAs

Hatch EQ Program Summary Description

Hatch EQ Program Responsibilities

EQ Process

- Original qualification basis
- EQ master list
- EQ maintenance
- Replacement of EQ equipment
  - Replace the existing equipment with identical equipment.
  - Replace the equipment with different equipment which is currently evaluated under the EQ program.
  - Replace the equipment with different equipment which is not currently evaluated under the EQ program.
  - Reanalyze the qualified life calculation.
- Refurbishment of EQ equipment
- Procurement of EQ equipment
- Plant environmental changes

4.4.1 PROCESS FOR IDENTIFYING EQ TLAAS

For the purposes of identifying TLAAs, Southern Nuclear reviewed the QDPs and the supporting calculations for the six qualifying criteria. The primary sorting criteria in this effort were Criterion 3 (whether the component was qualified for at least 40 years) and Criterion 4 (whether the analysis was relevant in making a safety determination with regard to the component being qualified).

Analyses for those components with qualified lives less than 40 years did not meet Criterion 3.

Each QDP contains Environmental Qualification Report Evaluations (EQREs) and supporting calculations. Southern Nuclear reviewed the EQREs and support calculations for the six criteria. Southern Nuclear determined that some met the definition of a TLAA. More than one demonstration method was applicable for some of the TLAAs because multiple installations of similar equipment were evaluated. All three demonstration methods may apply to certain TLAAs. Of special interest are those TLAAs that indicate that at least some of the evaluated components qualified lives cannot currently be projected to the end of the extended license term. The aging effects for these components are managed by the EQ Program per the requirements of 10 CFR 50.49. For some of the TLAAs, the components are qualified through the end of the period of extended operation, with the exception of specific applications inside containment at higher elevations where the temperatures are known to exceed the 60-year qualified life temperature. Equipment with less than a 60-year qualified life is managed by the EQ program in the same way equipment with qualified lives less than the original 40-year license term is managed.

Some calculations were more general in nature. One general class of calculations, for example, determined the 40-year radiation dose in a given area containing in-scope equipment. The total integrated radiation dose calculations apply to multiple QDPs and enable qualification of components to the end of the extended period of operation.

The rest of the TLAAs are valid for the extended license period with minor qualitative documentation changes.

<u>GSI 168 - Environmental Qualification of Electrical Equipment.</u> Generic Safety Issue 168 was reviewed by Southern Nuclear to identify any generic concerns that may be related to the effects of aging within the scope of the license renewal rule.

With regard to that GSI, Southern Nuclear will continue to manage the effects of aging in accordance with the current licensing basis, as modified as appropriate to address regulatory changes that might evolve through the final resolution of that TLAA.

4.4.2 HATCH ENVIRONMENTAL QUALIFICATION PROGRAM SUMMARY DESCRIPTION

The Nuclear Regulatory Commission (NRC) established nuclear plant EQ requirements in General Criterion 4 of 10 CFR 50 Appendix A and in 10 CFR 50.49, which specifically require that an EQ program be established to demonstrate that certain electrical equipment located in "harsh" plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line breaks (HELBs), and post-LOCA radiation) are qualified to perform their safety function in those harsh environments. The requirements of 10 CFR 50.49 apply to all new and replacement electrical equipment, within the scope of 10 CFR 50.49, purchased after February 22, 1983. The scope of equipment covered by the Hatch EQ program is:

- Safety-related (in accordance with the definition in 10 CFR 50.49(b), consistent with the Plant Hatch CLB) electrical equipment located in a postulated harsh environment that is required to mitigate the consequences of the accident causing the harsh environment, or whose subsequent failure can degrade safety systems or mislead the plant operator.
- Nonsafety-related electrical equipment located in a postulated harsh environment whose failure could prevent a safety function or mislead the plant operator. The impact to emergency operation procedures should be considered in the failure analysis.
- Certain post-accident monitoring equipment located in a postulated harsh environment designated as requiring qualification in the Regulatory Guide 1.97 section of the licensee's response to Supplement 1 of NUREG-0737.

The Hatch EQ program is described in section 7.16 of the Unit 1 FSAR and section 3.11 of the Unit 2 FSAR (References 12 & 13) and is administratively controlled by procedures which define the responsibilities and requirements for implementing the Hatch EQ program to ensure compliance with 10 CFR 50.49.

The Hatch EQ program is currently implemented as described in this summary. Changes in the implementation of the Hatch EQ program as described in this summary are made whenever appropriate by changing the controlling procedure(s). Changes to the procedures for the EQ program are administratively controlled by a procedure which gives instructions for administrative procedures and by the Hatch quality assurance process to ensure continued compliance with 10 CFR 50.49.

The Hatch EQ program consists of activities which are integrated into the overall plant design and modification process, including initial design and modification (e.g., selection and application of equipment), documentation review and approval, maintenance, refurbishment, replacement, and procurement. A summary description of these activities and how they are implemented follows in sections 4.4.3 and 4.4.4.

4.4.3 HATCH EQ PROGRAM RESPONSIBILITIES

Hatch EQ program responsibilities are assigned to several groups within the Southern Company.

- **Southern Nuclear** has among its responsibilities:
  - Providing overall administration of the EQ program
  - Resolving generic EQ issues
  - Providing technical support for EQ related issues
  - Controlling and administering the EQ procedures and qualification documentation (including the EQ Master List)
  - Providing input to the design engineering process
  - Managing qualification testing programs and performing qualification evaluations
  - Maintaining the EQ design basis documentation
  - Providing information to the plant groups to maintain qualification

- **Plant Engineering** has among its responsibilities:
  - Providing information and technical support to plant maintenance, procurement, planning, and other plant groups for EQ-related issues and processes.
  - Ensuring that all EQ mandated activities are addressed and scheduled.
  - Ensuring that the plant modification process addresses EQ requirements, including the type and degree of documentation required.
  - Initiating and monitoring site EQ-related procedure changes.
- **The site maintenance organization with input from the site EQ coordinator** has the responsibility for implementing plant maintenance procedures and ensuring that maintenance personnel are properly trained in and carry out the EQ program maintenance requirements.
- **The site procurement organization with input from the site EQ coordinator** has the responsibility for implementing plant procurement procedures and ensuring that procurement personnel are properly trained in performing the EQ program procurement requirements.
- **The site work planning organization with input from the site EQ coordinator** has the responsibility for establishing and implementing schedules that ensure plant procurement and maintenance activities are performed in a timely manner to support the EQ program requirements.

4.4.4 EQ PROCESS

In establishing the original qualification basis for the equipment and in developing the EQ Master List and EQ procedures, all equipment within the scope of 10 CFR 50.49 was reviewed per the requirements of the quality assurance program. Each test report was reviewed, a test report summary was placed on file, and each piece of equipment, by tag number, was reviewed to document that qualification of the equipment was adequate for its intended application.

The EQ process is controlled by the EQ Master List and the EQ procedures, which are described as follows:

EQ Master List

The EQ Master List provides an up-to-date, controlled listing of electrical equipment in the Hatch EQ program. All EQ Master List information must be originated and revised according to the procedure which controls the EQ program. The EQ Master List provides the following equipment information:

- Plant tag number of the equipment
- The manufacturer and model or series number for the equipment
- The building, floor elevation, and specific location of the equipment
- The applicable EQ QDP which addresses component qualification and maintaining the qualification of the equipment

EQ Maintenance

The Installation/Maintenance Procedure Outline (I/MPO) of the QDP defines the specific requirements for installing and maintaining EQ equipment in its qualified configuration. The I/MPO ensures consistency in maintaining the qualification of all electrical equipment within the scope of 10 CFR 50.49.

The EQ installation and maintenance information in the I/MPO is incorporated into the plant procedure(s) which control the EQ maintenance activities. The I/MPO may specifically address activities such as the following:

- EQ mandated maintenance required to maintain the equipment qualification
- Qualified life of the equipment, any component part to be replaced, and the replacement interval (e.g., replace cover o-ring every 18 months)
- Sealing of the equipment cable entrance to prevent moisture intrusion, as required
- Installation and mounting configurations required to maintain qualification
- Shelf life or storage requirements
- Procurement and reorder information specific to the equipment

Documentation such as maintenance manuals, test reports, calculations, and installation specifications from which the maintenance requirements originate, or which must be used to implement the maintenance requirements, is referenced in the I/MPOs. The requirements contained in the I/MPOs are incorporated not only into craft work procedures (maintenance, termination, sealing, installation), but also the work planning/management system (scheduling and replacement), and procurement procedures.

EQ Aging Management

For EQ components that are not qualified to the end of the extended operating period, aging effects will continue to be managed in accordance with the current licensing basis. 10 CFR 50.49 states: ". . . The equipment must be replaced or refurbished at the end of this designated life unless ongoing qualification demonstrates that the item has additional life."

Replacement of EQ Equipment

Prior to the expiration of the qualified life of a piece of EQ equipment, a maintenance work order is generated by the Hatch work management system to alert plant personnel that the equipment is scheduled for replacement in the near future. Several options are available:

- **Replace the existing component with an identical component -** This option only requires the generation of a work order and any necessary update to the EQ documentation to reflect component replacement, since all the required qualification documentation and procedures already exist.
- **Replace the equipment with different equipment which is already evaluated under the EQ program -** When new or replacement EQ equipment, which is currently addressed in the EQ program, is installed in the plant, the EQ Master List and documentation are changed to reflect the change in the QDP associated with the component. A review is performed which confirms that the EQ documentation:
  - Addresses the specific manufacturer and model number of the equipment.

  - Identifies the plant areas in which the component is qualified to be installed.
  - Identifies the applicable EQ test report and evaluation.
  - Identifies additional documentation relevant to the application versus the tested configuration and test parameters.
  - Identifies the normal and postulated accident environments to which the equipment is subject.
  - Identifies and records "upgrades" of components qualified to DOR Guidelines to components qualified to the 10 CFR 50.49 requirements.
  - Confirms that the new or replacement component is qualified for its application.

- **Replace the equipment with different equipment which is not currently evaluated under the EQ program** – Prior to replacing a piece of equipment with one not currently addressed in the EQ program, an EQRE is prepared that verifies qualification of the equipment. The EQRE, commonly also referred to as a "50.49 Checklist," includes information such as the following:
  - **Equipment Data** - Includes data such as equipment tag numbers, manufacturer, QA condition, specifications, and applicable test report.
  - **Functional Review** - Determines applicability of 10 CFR 50.49 to the equipment; i.e., installed in a postulated harsh environmental area, required to operate during an accident, etc.
  - **Environmental Qualification Review** - Examines appropriate aspects such as test parameters versus installed location accident parameters, operability times, qualified life, equipment tested versus installed equipment, and test report anomalies.

  The information identified above is evaluated and a determination is made whether or not the equipment is qualified for the intended application. For new qualifications, the QDP is then prepared, which provides complete supporting documentation, including test report(s) and evaluations, correspondence, calculations, System Component Evaluation Worksheets (SCEWs), and installation and maintenance requirements.

- **Reanalyze qualified life calculations** - The reanalysis is performed for specific applications to extend the qualified life if excess conservatism exists in the original qualified life calculation. Conservatisms may exist in parameters such as the assumed ambient temperature of the equipment, an unrealistically low activation energy, or in the application of equipment (for example, deenergized versus energized). The reanalysis is documented under a Qualification File Review Checklist (QFRC). The QFRCs document all changes to the EQ Central File. Typically, the guidelines outlined in EPRI methodologies and processes to optimize environmental qualification replacement intervals are followed (Ref. 14). Specific aspects of the way a reanalysis is performed are discussed below:

- **Analytical Methods -** The Arrhenius methodology is the thermal model used to perform a reanalysis. During normal operations, equipment is only subjected to ambient humidity levels (20-90%), which was also dismissed as an aging stressor per the NRC EQ Task Action Plan (Ref. 15). EQ equipment is typically sealed and cable insulation is protected from the occasional inadvertent spray. Exposure to moisture due to leaks is investigated on a case-by-case basis. The analytical method used for radiation reanalysis identified the 40-year radiation dose from the EQ criteria manual for the area where the equipment is installed, multiplied that value by the ratio of the evaluation period divided by 40 years (e.g., for license renewal 60 years/40 years, or 1.5), and added the applicable accident radiation dose to obtain the total integrated dose for the equipment. Southern Nuclear has specifically assessed the impact of life extension from 40 to 60 years on the EQ radiation exposures for both units.
- **Data Collection & Reduction Methods -** Reducing excess conservatisms in the equipment service temperatures used in existing analyses is the chief method used for reanalysis. Temperature data used in a reanalysis is obtained from actual temperature measurements in the area around the equipment being reanalyzed. Temperature measurements can be obtained in several ways, examples of which are through monitors used for Technical Specification compliance, other installed monitors, measurements made by plant operators during surveillance rounds, and temperature sensors on specific components. A representative number of temperature measurements are mathematically reduced to arrive at a temperature used in a reanalysis. Temperatures may be used in several ways in a reanalysis such as (a) using the actual calculated temperature, or (b) using the calculated temperature to validate or show conservatism when using the a design temperature for a reanalysis.
- **Underlying Assumptions -** Conservatisms in the EQ equipment qualification analyses have been maintained sufficiently to absorb environmental changes occurring due to plant modification and events. Major plant modifications or events at Plant Hatch of sufficient duration (such as power uprates) that may change temperature, pressure, and/or radiation values used in the underlying assumptions or in the EQ calculations, are addressed in the design phase prior to implementation of the plant modification or operational change. The process by which changes to the underlying assumptions are made is discussed in the section of this summary program description entitled Plant Environmental Changes.
- **Acceptance Criteria & Corrective Actions -** Adequate margin, as suggested in IEEE Std. 323-1974 and DOR Guidelines, is maintained in all reanalyses, or adequate justification for not maintaining margin is provided. If the reanalysis does not maintain adequate margin and less margin cannot be justified, the equipment qualification is not extended and the equipment is replaced (for example) as scheduled prior to the expiration of the existing qualification.

Refurbishment of EQ Equipment

When equipment needs refurbishment, it is typically replaced with new equipment or previously-refurbished equipment taken out of storage. The removed equipment is then discarded or refurbished and placed in storage. Qualified equipment is required to be refurbished before it can be placed back into storage, if the equipment is to be used in EQ applications following storage. Refurbishment is performed in a manner that preserves its qualification. This is typically accomplished by replacing "soft" items such as gaskets, seals, and wires which have a limited life.

The EQ limited-life replacement parts are identified in the I/MPO and EQ maintenance procedures and vendor manuals for a particular piece of equipment, manufacturer, and model. Additionally, guidance for shelf life of refurbished equipment is contained in the documentation.

Procurement of EQ Equipment

Procurement policy and criteria for EQ equipment within the scope of 10 CFR 50.49 are controlled by Southern Nuclear procedure(s) for equipment procurement, the site procedure(s) for procurement, and the Nuclear Quality Assurance Program.

Procurement of like-for-like replacement EQ equipment is controlled, such that the procured equipment is as good as or better than the original equipment. The procurement process also assures applicable performance requirements and qualification criteria are met. Information is found in the component's QDP to facilitate procurement, such as the manufacturer or vendor from which to purchase the equipment, the test reports to be referenced on the requisition, and equipment specifications, etc.

Southern Nuclear reviews specifications for procurement of new EQ equipment to ensure applicable performance requirements and qualification criteria are met. Test plans are reviewed and approved prior to testing to assure compliance with the specification. Upon receipt of a new test report, the responsible engineer will initiate an EQ test report evaluation that establishes the qualification of the equipment. A copy of the evaluation is also inserted into the QDP. Updating the EQ Master List and the QDP are handled similar to the replacement process addressed above.

Plant Environmental Changes

Plant environmental conditions (both normal and accident) are documented in an Engineering Specification (Ref. 16). This specification identifies the harsh environment areas of the plant for LOCAs, HELBs, and radiation consistent with the CLB. Section A of the Central File includes the different temperature and pressure profiles for the various accident scenarios including worst-case composite accident profiles for the various containment and reactor building harsh environment areas. Section F of the Central File and the QDPs include supporting calculations for these accident profiles and radiation total integrated doses. All specifications, calculations, and the other Central File documents are controlled documents.

The measurements of critical parameters (e.g., containment temperatures for Technical Specification requirements) are taken on an ongoing basis. Southern Nuclear reviews changes in environmental parameters, whether as found or anticipated due to an impending design change.

When a significant environmental change is identified, a review of the qualification of affected EQ equipment is performed and applicable changes are made to the equipment's qualified life and QDP documentation. The EQ calculations, Specification, and accident profiles, if appropriate, are revised to reflect the new operating conditions.

4.4.5 ENVIRONMENTALLY QUALIFIED EQUIPMENT SUBJECT TO TLAA DEMONSTRATION

Figure 4.4-1 through Figure 4.4-107 contain detailed evaluations of the equipment qualifications for Plant Hatch. The EQ Program referred to in these figures is the one discussed in sections 4.4.1 through 4.4.4 of the LRA.

Figure 4.4-1 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve (MOV)
Specific Description:	Limitorque Corp. SB, SMB Actuators, DC Service
Location:	Outside Containment
QDP:	Unit 1/2, QDP 1B/1B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The qualified life has been projected to the end of the period of extended operation for all applications when considering thermal aging only. Seven of these MOVs are not currently qualified through the period of extended operation due to a life-limiting radiation total integrated dose. The qualified lives limited by radiation are as follows:

Unit 1 MOVs located in the pipe chase have a qualified life of 50 years, and MOVs in the RWCU heat exchanger room have a qualified life of 59 years.

Unit 2 MOVs located in the pipe penetration room have a qualified life of 40 years; MOVs located in the pipe chase have a qualified life of 47 years; and MOVs in the RWCU heat exchanger room have a qualified life of 59 years.

For MOVs with qualified lives less than 60 years, aging effects will be managed by the EQ program.

Note:

1. Aging for the DC actuator qualification included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years. If cycle aging cannot be extended to 60 years, then this component will be managed by the EQ Program.

Figure 4.4-2 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve
Specific Description:	Limitorque Corp. SB, SMB Actuators, AC Service
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 1C/1C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The component qualified lives have been projected through the end of the period of extended operation when considering thermal aging. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Aging for the BWR containment qualification included mechanical aging, compared to the minimum 500 cycles for a 40-year qualified life, per IEEE 382-1972. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-3 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor-Operated Valve
Specific Description:	Limitorque Corp. SB, SMB Actuators, AC Service
Location:	Outside Containment
QDP:	Unit 1/2, QDP 1E/1E
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Qualified lives have been projected through the end of the period of extended operation when considering thermal aging. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Aging for the Outside BWR containment actuator qualification included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-4 Equipment Qualification TLAA Demonstration

Commodity Type:	Torque and Limit Switches
Specific Description:	Limitorque SMB, SB, SBD, SMB/HBC
Location:	Inside/Outside Containment
QDP:	Units 1/2, QDP 1F/1F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Qualified lives have been projected through the end of the period of extended operation when considering thermal and radiation aging.

Note:

1. Aging in the qualification report included mechanical aging for a 40-year qualified life, per IEEE 382-1980. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-5 Equipment Qualification TLAA Demonstration

Commodity Type:	Electrical Penetrations
Specific Description:	General Electric F01 Electrical Penetration Assembly
Location:	Inside Containment
QDP:	Unit 1/2 QDP 2/2
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Using the original thermal aging test data in conjunction with supplemental data, the General Electric F01 electrical penetration assembly qualified lives have been projected through the end of the period of extended operation.

A supplemental General Electric test report was evaluated to extend the radiation qualification to radiation levels greater than the 60-year total integrated dose, plus margin. The General Electric F01 electrical penetration assemblies are considered qualified through the end of the period of extended operation by test and supplemental analysis.

Figure 4.4-6 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable Connector
Specific Description:	Amphenol Type HN Plug Connectors
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 2A/2A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Amphenol Type HN Plug Connectors are used in the electrical penetrations inside the drywell. The Amphenol Type HN plug connector qualified lives have been projected through the end of the period of extended operation based on thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-7 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable Connector
Specific Description:	Veam Series CIR Nuclear Multipin Connector
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 2B/2B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Veam Series CIR nuclear multipin connector qualified lives have been established through the end of the period of extended operation for the worst-case normal temperature and radiation conditions at Plant Hatch.

Figure 4.4-8 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks
Specific Description:	States ZWM and NT Series Terminal Blocks
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 4/4
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The States terminal block qualified lives can be projected to the end of the period of extended operation when used in applications outside containment when considering both thermal and radiation aging.

The radiation aging performed on the States ZWM and NT terminal block material does not support extending the qualified life to 60 years for applications inside containment. For these States ZWM and NT terminal blocks, the aging effects will be managed by the EQ program.

Figure 4.4-9 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers (MCC)
Specific Description:	Allis Chalmers Value Line Mark 1 AC MCCs and Local Starters
Location:	Outside Containment
QDP:	Unit1/2, QDP 6/6
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has projected the qualified lives of the MCC subcomponents to the end of the period of extended operation, with the exception of the molded case circuit breakers, thermal overloads, and the control power transformers. For molded case circuit breakers, thermal overloads, and control power transformers, the aging effects will be managed by the EQ program.

Figure 4.4-10 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuse Blocks
Specific Description:	Bussman Class H, K and R Phenolic
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6B/6B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The fuse blocks are installed in MCCs on the elevation 130 ft of the reactor building in both units. The qualified lives have been projected to the end of the period of extended operation at normal service temperatures. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The fuse blocks are qualified to the end of the period of extended operation.

Figure 4.4-11 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relay
Specific Description:	Struthers - Dunn Relay 219BBX222NE & Socket CX3964NE
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6F/6F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects.

Conclusion:

The Struthers - Dunn Relay 219BBX222NE & Socket CX3964NE are qualified for use in the MCCs on El. 130 ft of the reactor building. In the test program, accelerated aging times and temperatures were established (also considering coil heat rise) to achieve 40-year life plus the accident plus margin.

The qualified lives could not be extended significantly and, therefore, the aging effects will be managed by the EQ program.

Figure 4.4-12 Equipment Qualification TLAA Demonstration

Commodity Type:	Molded Case Circuit Breaker (MCCB)
Specific Description:	Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, HMCP
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6G/6G
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects.

Conclusion:

The Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, and HMCP MCCBs are qualified for use in MCCs on El.130 ft of the Reactor Building.

When used in normally energized applications, the qualified life based on thermal aging data is always less than 40 years.

MCCBs in normally deenergized applications have qualified lives calculated as follows, based on thermal aging data:

HFB	56 years
HFD	88 years
HMCP	55 years

The HFDs are qualified to the end of the period of extended operation. Some HFBs and HMCPs are qualified to the end of the period of extended operation, depending on installation date. If not, the aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-13 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relays with Heaters
Specific Description:	Westinghouse Type AA and AN Relay w/ FH Series Heater Element
Location:	Outside Containment
QDP:	Unit 1/2, QDP 6H/6H
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AA and AN Thermal Overload Relays with FH Series Heater Elements are qualified for use in MCCs on EL. 130 ft of the reactor building.

When used in normally energized applications, the qualified life is less than 40 years based on thermal aging data.

Normally deenergized components have a qualified life of greater than 60 years based on thermal aging.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Qualification of the normally deenergized Westinghouse Type AA and AN thermal overload relay with FH series heater element is valid for the period of extended operation.

Figure 4.4-14 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers
Specific Description:	Cutler Hammer DC Unitrol MCCs
Location:	Outside Containment
QDP:	Unit1 QDP 7
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has projected the qualified lives of the DC MCC subcomponents to the end of the period of extended operation (for both thermal and radiation), with the exception of the molded case circuit breakers, thermal overloads, and control power transformers. For molded case circuit breakers, thermal overloads, and control power transformers, aging effects will be managed by the EQ program.

Figure 4.4-15 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem WCSF Heat Shrinkable Tubing and Kits NESK and NCBK Breakout and Tubing Kits NMCK Nuclear Motor Connection Kits
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8A, 8B, 8J/7A, 7B, 7J
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem kits are used in applications inside and outside containment, and are qualified for 60 years at 194 °F (90 °C), which bounds all applications. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

The Raychem kits qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-16 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem HVT and NHVT Kits
Location:	Outside Containment
QDP:	Unit 1/2 QDP 8C/7C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem kits are used in applications outside containment, and are qualified for 60 years, based on thermal aging. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

The Raychem kit qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-17 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Stub Connection Kit
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8E/7E
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem kit is used in applications inside and outside containment. The Raychem materials are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. All outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications are qualified for 60 years at ambient temperatures below 187 °F. For inside containment applications with higher service temperatures (and falling short of 60-year qualification), aging effects will be managed by the EQ program.

Figure 4.4-18 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Nuclear Plant Transition Splice Assembly Kits
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8F/7F
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem Nuclear Plant Transition Splice Assembly kits are used in applications inside and outside containment. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. Outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications at ambient temperatures below 187 °F are considered to have a qualified life of 60 years. For inside containment applications with higher service temperatures (and falling short of 60-year qualification), the aging effects will be managed by the EQ program.

Figure 4.4-19 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem 8-kV Inline Motor Connection Splice Kits
Location:	Outside Containment
QDP:	Unit 1/2 QDP 8H/7H
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Raychem 8-kV Inline Motor Connection Splice kits are used in applications outside containment. The Raychem materials are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The outside containment application qualified lives have been projected to the end of the period of extended operation.

Figure 4.4-20 Equipment Qualification TLAA Demonstration

Commodity Type:	Splices
Specific Description:	Raychem Breakout/Scotchcast 9 Potting Compound
Location:	Inside/Outside Containment
QDP:	Unit 1/2 QDP 8K/7K
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Raychem Scotchcast 9 Potting Compound is used in applications inside and outside containment with Raychem Breakout Kits. The Scotchcast material is qualified to radiation levels higher than the worst-case 60-year total integrated dose, plus margin. The outside containment applications will not experience temperatures in excess of 135 °F. All outside containment application qualified lives have been projected to the end of the period of extended operation.

Inside containment applications have a qualified life of 60 years at ambient temperatures below 180 °F. For inside containment applications with localized higher service temperatures (and falling short of 60-year qualification), the aging effects will be managed by the EQ program.

Figure 4.4-21 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Switches
Specific Description:	Electroswitch Series 20 and Series 40 Control Switches
Location:	Outside Containment
QDP:	Unit 1, QDP 9
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Electroswitch Series 20 and Series 40 control switches qualified lives have been projected to the end of the period of extended operation considering thermal aging. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. The switches were cycle-aged to simulate 40 years of nuclear generating station service. This cycle-aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-22 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	Target Rock Corporation Model 76HH-002
Location:	Outside Containment
QDP:	Unit 1/2, QDP 10/8
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-23 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve Upgrade Modification Kits
Specific Description:	Target Rock Corporation Model 82X-007H
Location:	Outside Containment
QDP:	Unit 1/2, QDP 10A/8A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-24 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Operated Globe Valve
Specific Description:	Target Rock Corporation Model 91J-001
Location:	Outside Containment
QDP:	Unit 1, QDP 10B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The qualification test was performed on Target Rock model 82X-007H. Model 91J-001 is qualified by similarity.

The original qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Figure 4.4-25 Equipment Qualification TLAA Demonstration

Commodity Type:	Fan Motor
Specific Description:	Reliance Class H Type RH Insulation System
Location:	Outside Containment
QDP:	Unit 1/2, QDP 11/9
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Reliance Class H Type RH Insulation System fan motors are qualified for use in certain locations outside containment.

The qualified life has been calculated to be 44 years based on thermal aging data. Based on installation dates, the installed fan motors are qualified to the end of the period of extended operation.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-26 Equipment Qualification TLAA Demonstration

Commodity Type:	Insulated and Uninsulated Terminals and Splices
Specific Description:	AMP Special Ind. Insulated and Uninsulated Terminals and Splices
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 13/11
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The AMP Special Ind. insulated and uninsulated terminals and splice qualifications have been projected to the end of the period of extended operation by these calculations. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-27 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	GE Vulkene Internal Panel Wire Model SI-57275
Location:	Outside Containment
QDP:	Unit 1/2, QDP 14A/12A
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE Vulkene Internal Panel Wire Model SI-57275 is used in panels outside containment.

The qualification has been projected to the end of the period of extended operation.

Figure 4.4-28 Equipment Qualification TLAA Demonstration

Commodity Type:	Switchboard Wire
Specific Description:	GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE)
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 14B/12B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE) is qualified for use inside and outside containment.

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The GE Vulkene Supreme Type SIS Wire Model SI-57279 (XLPE) is qualified for 60 years at 188 °F. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For inside containment applications with localized higher service temperatures which cannot be projected to the end of the period of extended operation, the aging effects will be managed by the EQ program.

Figure 4.4-29 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Okonite Low and Medium Voltage Power and Control Cables; and Instrument Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 17/14
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Okonite low and medium voltage power and control cable qualified lives, and instrument cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-30 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	BIW Coaxial, and Low Voltage Power, Control and Instrument Cable
Location:	Inside/Outside Containment
QDP:	Unit 1, QDP 18A & 18C
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have be reevaluated at maximum average (actual) service temperatures. The BIW low voltage power, control and instrument cable; and BIW coaxial cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-31 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	BIW Instrument and Control Cable
Location:	Outside Containment
QDP:	Unit 1, QDP 18B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The BIW Instrument and Control Cable qualified lives have been projected to the end of the period of extended operation when considering thermal aging. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-32 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	Okonite T-95 Insulating and No. 35 Jacketing Tapes With Cement
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 19/29
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The splice tapes are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The Okonite T-95 insulating and No. 35 jacketing tapes have been qualified for 60 years at 188 °F.

When the Okonite T-95 insulating and No. 35 jacketing tapes are used in inside containment applications where the localized service temperature is greater than 188 °F, the qualified lives are shorter than 60 years. For these Okonite T-95 insulating and No. 35 jacketing tapes, the aging effects will be managed by the EQ program.

Figure 4.4-33 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	Okonite T-95 Insulating and No. 35 Jacketing Tapes Without Cement
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 19B/29B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Thermal Aging:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) are qualified for 60 years at 170 °F.

When the Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) are used in applications where the localized service temperature is greater than 170 °F, the qualified lives are shorter than 60 years.

Radiation Aging:

The Okonite T-95 insulating and No. 35 jacketing tapes (configured without cement) were tested to 1.07 E8 rads. For applications where the 60-year normal dose plus accident dose plus 10% margin exceeds 1.07 E8 rads, the qualified life is less than 60 years due to radiation. The worst-case radiation environment occurs in the drywell, where the 60-year total integrated dose is as high as 1.22 E8 rads. In this worst case, the qualified life is limited to 48 years based on radiation.

Qualified Life

The qualified life of a splice is currently the most limiting (the lesser) of the two qualified lives.

Many splices have been projected to the end of the period of extended operation. For others, the aging effects will be managed by the EQ program.

Figure 4.4-34 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	ASCO NP and 206 Series (Deenergized only)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 22/20
Methodology:	NUREG 0588
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Only deenergized ASCO NP and 206 Series solenoid valves located outside containment are included. The 206 series, and models NP8344 and NP8320 qualifications are valid for the period of extended operation for all outside containment applications.

Based on thermal aging data, Models NP8321 and NP8316 have been projected to the end of the period of extended operation for all applications except the Unit 1 torus, personnel access room, and steam chase. In these areas the qualified lives are less, and the aging effects will be managed by the EQ program.

The ASCO NP and 206 Series solenoid valves are qualified to radiation levels greater than the worst-case 60-year total integrated dose.

Note:

1. The ASCO NP and 206 Series solenoid valves were electrically cycled at maximum operating pressure. Prior to extending the qualified lives beyond the current operating license term, the qualified life based on the cycle aging data will be addressed in the current term.

Figure 4.4-35 Equipment Qualification TLAA Demonstration

Commodity Type:	Limit Switches
Specific Description:	NAMCO EA180 and EA740
Location:	Inside/Outside Containment
QDP:	Unit1/2, QDP 23/15
Methodology:	NUREG 0588, 10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The NAMCO EA180 and EA740 limit switches are qualified for use inside and outside containment. Qualified lives vary depending on application-specific ambient temperatures and radiation levels. For many applications, qualification is valid for the period of extended operation when considering thermal aging and radiation aging. Others have been projected to the end of the period of extended operation. When the qualified life is less than 60 years based on both thermal aging and radiation aging, qualified life is based on the most limiting of the two, and the aging effects will be managed by the EQ program.

Note:

1. The NAMCO EA180 and EA740 limit switches were cycled to simulate the operating life (per IEEE 323-1974), in all test programs except one. In that test program, switches were cycle-aged to simulate a 6-year life (per IEEE 382-1980). Prior to extending the qualified lives within or beyond the current operating license term, the qualified life based on the cycle aging data will be addressed in the current term, to assess cycle aging impact on qualified life.

Figure 4.4-36 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Pressure Controls, Inc. (PCI) Model PPD 147D8668P003
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 25/25
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Component qualified lives in the drywell, steam chase, and personnel access have been reevaluated using actual service temperatures. The Pressure Controls pressure switches are qualified for 60 years at temperatures at or below 136 °F. At higher service temperatures, the qualified lives are less and the aging effects will be managed by the EQ program. The pressure switches are qualified to radiation levels greater than the worst-case 60-year total intregrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of this data shows that the product performance qualification specification requirement was met, and that there was no degradation due to operational cycle aging. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-37 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Anaconda Low Voltage Power, Control, Instrumentation Cables and Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 27/27
Methodology:	NUREG 0588
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Anaconda low voltage power, control, instrument cables and internal panel wiring are qualified for 60 years at 158 °F. At higher service temperatures, the qualified lives are less and the aging effects will be managed as described by the EQ program. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-38 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Anaconda Low Voltage Power, Control, and Instrumentation Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 27A/27A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Anaconda low voltage power, control, and instrument cables are all qualified for 60 years at 158 °F. At localized higher service temperatures, the qualified lives are less and the aging effects will be managed by the EQ program. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-39 Equipment Qualification TLAA Demonstration

Commodity Type:	Radiation Detector and Cable
Specific Description:	Victoreen Model 877-1 Detector and Model 878-1-9 Cable
Location:	Inside Containment
QDP:	Unit 1/2, QDP 28/30
Methodology:	NUREG 0588 Cat.1
TLAA Demonstration Option:	Detector: Criterion (i): Valid for the Period of Extended Operation Cable: Criterion (iii): Manage the Aging Effects

Conclusion:

No thermal aging was required for the detector, as all parts are stainless steel, nickel, or aluminum. The radiation detector is not age-sensitive, and is qualified for 60 years. The detector is refurbished, recalibrated, and recertified every 5 years.

The qualified life of the Victoreen model 878-1-9 cable assemblies could not be projected to the end of the period of extended operation based on the actual service temperatures. For cable assemblies, the aging effects will be managed by the EQ program.

The detector and cable are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-40 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Operated Globe Valves
Specific Description:	Target Rock 82VV Series
Location:	Outside Containment
QDP:	Unit 1/2, QDP 29/31
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Unit 1 - Criterion (ii): Projection to the End of the Period of Extended Operation. Unit 2 - Criterion (i): Valid for the Period of Extended Operation

Conclusion:

For Unit 2, the original qualification is valid for the period of extended operation, with minor documentation changes.

For Unit 1, the original qualification of the Target Rock 82VV solenoid valves has been projected to the end of the period of extended operation based on the normal operating temperatures of the installed locations.

The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-41 Equipment Qualification TLAA Demonstration

Commodity Type:	Conduit Seal
Specific Description:	Rosemount 353C
Location:	Outside Containment
QDP:	Unit 1/2, QDP 30/32
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The thermal aging analysis is presented in the test report. A qualified life of 60 years is given for an ambient operating temperature of 115 °F.

The Rosemount 353C conduit seals qualification has been projected to the end of the period of extended operation for all current Unit 1 and 2 applications.

The conduit seals are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-42 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	Valcor V526 Series (De-energized)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 31/33
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The original qualification covers both energized and deenergized solenoid valves. The energized solenoid valves have a qualified life less than 40 years, and are on a schedule for repetitive replacement. This demonstration covers only the deenergized solenoid valves.

For the deenergized solenoid valves, qualified life has been projected to the end of the period of extended operation using vendor test report aging data. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. The valve was cycle tested. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-43 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Static-O-Ring Model 4N6-B5-NX-C1A -JJTTX6
Location:	Outside Containment
QDP:	Unit 1/2, QDP 32/65
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The qualified lives are greater than 60 years based on thermal aging. The switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Note:

1. The Static-O-Ring Model 4N6-B5-NX-C1A -JJTTX6 is qualified by cycle testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-44 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ
Location:	Outside Containment
QDP:	Unit 1/2, QDP 32A/65A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ pressure switch qualification covers applications in the Northeast and Southeast Diagonals only. Based on normal design temperatures in these areas, qualified life is calculated to be 58 years for Unit 1 and 44 years for Unit 2. Although this is less than 60 years for both units, based on installation dates, all installed components are qualified to the end of the period of extended operation. In addition, the switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Existing qualification is valid for the period of extended operation, with minor qualitative documentation changes.

Note:

1. The Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ is qualified by cycle testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-45 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Element
Specific Description:	Pyco, Inc. Models122-7026 and 122-4030-04
Location:	Outside Containment
QDP:	Unit 1/2, QDP 33/35
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to End of the Period of Extended Operation.

Conclusion:

The Pyco, Inc. Models122-7026 and 122-4030-04 temperature element qualifications have been projected to the end of the period of extended operation based on thermal aging data. The components are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-46 Equipment Qualification TLAA Demonstration

Commodity Type:	Limit Switch
Specific Description:	NAMCO EA170 Series
Location:	Outside Containment
QDP:	Unit 1/2, QDP 34/36
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The NAMCO EA170 Series limit switches are qualified for use in reactor building elevation 130 ft. Based on thermal aging data, the qualified lives of the limit switches have been projected to the end of the period of extended operation, with periodic replacement of the elastomeric subcomponents. The limit switches are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. During testing, the NAMCO EA170 Series limit switches were cycle-aged. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-47 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Elements and RTV Sealant
Specific Description:	Weed Model 1AOD/611-1B-C-4-C-2-A2-0
Location:	Inside Containment
QDP:	Unit 1/2, QDP 35/37
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

For components inside the containment, the pipe chase, and the pipe penetration room qualified lives have been reevaluated using actual service temperature measurements, yielding a range of qualified lives depending on the application-specific temperature. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For components with qualified lives less than 60 years, the aging effects will be managed by the EQ program.

Figure 4.4-48 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Sensor Assemblies
Specific Description:	Weed Assembly Nos. N9017D1B (Dual); N9017S1B (Single)
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 48A/57A (Outside Containment) Unit 1/2, QDP 35B/37B (Inside Containment)
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The Weed temperature sensor assembly qualifications have been projected to the end of the period of extended operation for all outside containment applications based on design ambients.

The qualified lives for temperature elements located inside containment, pipe penetration room, and pipe chase could not be projected to the end of the period of extended operation based on thermal aging.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

For components with qualified lives less than 60 years, the aging effects will be managed by the EQ Program.

Figure 4.4-49 Equipment Qualification TLAA Demonstration

Commodity Type:	Primary Containment Post-LOCA H2 and O2 Analyzer
Specific Description:	Comsip, Inc. Model K-IV
Location:	Outside Containment
QDP:	Unit 1/2, QDP 37/39
Methodology:	NUREG 0588, Cat. I
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Comsip, Inc Model K-IV primary containment post-LOCA H2 and O2 analyzer has been qualified to the end of the period of extended operation.

The Reliance pump motor for the H2 and O2 analyzer was qualified in a separate test program and supplied by Reliance to Comsip. The motor is qualified to the end of the period of extended operation.

The Bostrad cable for the H2 and O2 analyzer was qualified in a separate test program and supplied by Boston Insulated Wire and Cable to Comsip. The cable is qualified to the end of the period of extended operation.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-50 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wiring
Specific Description:	Raychem Flamtrol Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 39/47
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Raychem Flamtrol Internal Panel Wiring qualification has been projected to the end of the period of extended operation for all applications. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-51 Equipment Qualification TLAA Demonstration

Commodity Type:	Heat Trace System for Post-LOCA H2 and O2 Analyzers
Specific Description:	Thermon Model SSK, Heater Cable Pipe Assembly (HCPA)
Location:	Outside Containment
QDP:	Unit 1/2, QDP 40/41
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Unit 2: Criterion (i): Valid for the Period of Extended Operation Unit 1: Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The heat trace system control panels are exempt from environmental qualification requirements due to location in a mild environment.

For Unit 2, the HCPA qualification is valid for the period of extended operation, with minor documentation changes.

Due to higher Unit 1 design temperature, the HCPA qualified life is less than 60 years. However, the HCPA is qualified to the end of the period of extended operation, based on the date of system installation.

The HCPA is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-52 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor
Specific Description:	GE 5K6339XC166A and 5K6339XC94A RHR and Core Spray Pump Motors
Location:	Outside Containment
QDP:	Unit 1/2 QDP 42/45
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE 5K6339XC166A and 5K6339XC94A RHR and core spray pump motors are installed outside containment in the NE and SE corner rooms. The motors were originally qualified for 40 years by test and analysis. The qualified life has been projected to the end of the period of extended operation when considering thermal aging data from the original analysis. The motors are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-53 Equipment Qualification TLAA Demonstration

Commodity Type:	Gauge Pressure Transmitter
Specific Description:	ITT/Barton Model 763
Location:	Outside Containment
QDP:	Unit 1/2, QDP 45/52
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

For installed locations, the qualification has been projected to the end of the period of extended operation when considering thermal aging. The transmitters are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of the vendor's operational cycling data shows that the product performance qualification specification requirement was met and that there was no degradation due to operational cycling. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-54 Equipment Qualification TLAA Demonstration

Commodity Type:	Differential Pressure Transmitter
Specific Description:	ITT/Barton Model 764
Location:	Outside Containment
QDP:	Unit 1/2, QDP 46/51
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

For installed locations, the qualification has been projected to the end of the period of extended operation when considering thermal aging. The transmitters are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. Operational cycling was performed by the vendor. Evaluation of the vendor's operational cycling data shows that the product performance qualification specification was met and that there was no degradation due to operational cycling. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-55 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Elements
Specific Description:	Weed Model 1AOD/611-1BD-C-6-C-2-A2-0 GE Model PPD 228B1877
Location:	Outside Containment
QDP:	Unit 1/2, QDP 48/57
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

The qualified life exceeds 60 years where average temperatures are 114 °F or less. For all areas outside containment except the Unit 1 and the Unit 2 pipe penetration rooms and pipe chases, the temperature element qualification has been projected to the end of the period of extended operation when considering thermal aging.

The qualified lives for temperature elements located inside the pipe penetration room and pipe chase (where the actual temperatures can exceed 114 °F) have been determined. For these components, aging effects will be managed by the EQ program.

The temperature elements are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-56 Equipment Qualification TLAA Demonstration

Commodity Type:	EMI Filter Assembly
Specific Description:	GE Part No. 228B1892
	ITT Barton Catalog No.0768-1009-B
Location:	Outside Containment
QDP:	Unit 1/2, QDP 49/48
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The qualified life has been projected to the end of the period of extended operation when considering thermal aging for installed applications. The EMI filter assembly is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-57 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Block
Specific Description:	Buchanan NQB112
Location:	Outside Containment
QDP:	Unit 1/2, QDP 50/43
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Based on thermal aging data, the qualified lives of the Buchanan NQB112 terminal blocks have been projected to the end of the period of extended operation for all applications except those in the Unit 1 torus, pipe penetration room and pipe chase. In these areas, the normal ambient temperature yields a qualified life of 47 years. For terminal blocks used in these areas, aging effects will be managed by the EQ program. The terminal blocks are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-58 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switches
Specific Description:	Square D Model 9012-ACW-22 Pressure Switches
Location:	Outside Containment
QDP:	Unit 1/2 QDP 51/56
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Square D Model 9012-ACW-22 pressure switches in the HPCI turbine control panel is qualified for 40 years . The thermal aging data do not support extending the qualified life to 60 years. The Square D Model 9012-ACW-22 pressure switches aging effects will be managed by the EQ program.

Figure 4.4-59 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks and Speed Detector
Specific Description:	Square D Model 1828 Terminal Block and Woodward Model 1680 Magnetic Pickup Speed Detector
Location:	Outside Containment
QDP:	Unit 1/2 QDP 51B / 56B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Square D Model 1828 terminal block and woodward model 1680 magnetic pickup speed detector is used in the HPCI turbine controls located outside containment. The analysis and data will support a 60-year qualified life based on an ambient temperature of 148 °F (maximum design basis event (DBE) temperature). The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualified lives of the Square D Model 1828 terminal block and Woodward Model 1680 magnetic pickup speed detector have been projected to the end of the period of extended operation.

Figure 4.4-60 Equipment Qualification TLAA Demonstration

Commodity Type:	Solenoid Valve
Specific Description:	GE/ASCO Model HVA-176-816
Location:	Outside Containment
QDP:	Unit 1/2, QDP 52/53
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The GE/ASCO Model HVA-176-816 solenoid valve is qualified for use on the 130 ft elevation of the reactor building. The qualified life of the component has been projected to the end of the period of extended operation when considering thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. During testing, the component was cycle-aged. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-61 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Brand-Rex Low Voltage Power, Control, Instrumentation Cables and Internal Panel Wiring
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 54/18
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Brand-Rex low voltage power, control, instrument cables, and internal panel wiring are all were not qualified for 60 years at 189 °F. At localized higher service temperatures, the cable qualified lives weren't projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-62 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Rockbestos Firewall III Control and Instrumentation Cables
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 57/61
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Rockbestos Firewall III control and instrumentation cables are qualified for 60 years at 189 °F, which includes all applications. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-63 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Rockbestos Adverse Coaxial, Twinaxial, and Triaxial Cable
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 57A,B/61A,B
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Rockbestos adverse coaxial, twinaxial, and triaxial cable are all qualified for 60 years at 151 °F, which incudes all current applications. The cables are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-64 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks and Lugs
Specific Description:	Marathon, Buchanan, GE, Curtis, Burndy, Hollingsworth, Thomas & Betts Terminal Blocks and Lugs - Various
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 58/62
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects (Unit 2 Terminal Blocks only.)

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures.

The Marathon, Buchanan, GE, Curtis, Burndy, Hollingsworth, and Thomas & Betts terminal blocks and lugs (various) are all qualified for 60 years for all applications on Unit 1.

For Unit 2, Lugs are qualified for 60 years in all applications. The terminal blocks are qualified for 60 years, except in a few specific applications that exceed the 60-year qualified life temperature. Where service temperatures exceed the specified temperature, the terminal block qualified lives were not projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-65 Equipment Qualification TLAA Demonstration

Commodity Type:	Space Heater
Specific Description:	Ward Leonard 30/25F Limit Switch Compartment Space Heater
Location:	Outside Containment
QDP:	Unit 1/2 QDP 59/63
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Ward Leonard 30/25F limit switch compartment space heaters are installed in the limit switch compartments of Limitorque MOV operators. These heaters are wire wound or carbon film resistive elements encapsulated in a vitreous enamel or ceramic glaze. The materials of construction for the heaters are not considered age sensitive to either temperature or radiation exposures. Therefore, any installed Ward Leonard 30/25F limit switch compartment space heaters are considered qualified to 60 years (valid for the period of extended operation).

Figure 4.4-66 Equipment Qualification TLAA Demonstration

Commodity Type:	High Temperature Wire
Specific Description:	Valcor Silicone with Glass Braid
Location:	Inside /Outside Containment
QDP:	Unit 1/2, QDP 60/64
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

This cable is used as lead wire for EQ components. The qualified life of the wire has been projected to the end of the period of extended operation when considering thermal aging. The wire is qualified to radiation levels greater than the worst-case 60-year total integrated dose.

Figure 4.4-67 Equipment Qualification TLAA Demonstration

Commodity Type:	Conduit Seals and Thread Sealant
Specific Description:	Patel Model 841206 Conduit Seals and Patel P-1 Thread Sealant
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 61/66
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

The Patel P-1 thread sealant has a useful temperature range of -400 to 850 °F. The material is a highly temperature-stable graphite, and is exempt from thermal aging. It is also insensitive to radiation. Qualification has been projected to the end of the extended operation.

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Patel Model 841206 conduit seals are qualified for 60 years at 172 °F.

When the Patel Model 841206 conduit seals are used in applications where the service temperature is greater than 172 °F, the qualified lives are shorter than 60 years. For these Patel Model 841206 conduit seals, the qualified lives could not be projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The conduit seals are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-68 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Block
Specific Description:	Marathon 216HB Terminal Block with Screws
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 63/67
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The qualified lives of the Marathon 216HB terminal blocks have been projected to the end of the period of extended operation based on the normal operating temperatures in the installed locations. The terminal blocks are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-69 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Thermoswitch (Model 18021-0)
Location:	Outside Containment
QDP:	Unit 1 QDP 66
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Thermoswitch (Model 18021-0) qualification is valid for the period of extended operation at normal ambient temperatures. The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-70 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relay
Specific Description:	Allen Bradley Model 700-N and 700DC-N Control Relays
Location:	Outside Containment
QDP:	Unit 1/2 QDP 67A/72E
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Allen Bradley Model 700-N and 700DC-N control relays in the standby gas treatment system control panels are qualified for 50 years. The thermal aging data do not support extending the qualified life to 60 years. For Allen Bradley Model 700-N and 700DC-N relays, the aging effects will be managed by the EQ program.

Note:

1. The Allen-Bradley control relays were cycled during qualification testing. Prior to extending the qualified lives beyond 40 years, this cycle aging data will be reevaluated to assess impact on qualified life.

Figure 4.4-71 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Transformer
Specific Description:	General Electric Model 9T56Y2830 and 9T58B2830 Control Transformers
Location:	Outside Containment
QDP:	Unit 1 QDP 67C
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The General Electric Models 9T56Y2830 and 9T58B2830 control transformers in the standby gas treatment system control panels are qualified for 42 years. The thermal aging data do not support extending the qualified life to 60 years. For the General Electric Models 9T56Y2830 and 9T58B2830 control transformers, aging effects will be managed by the EQ program.

Figure 4.4-72 Equipment Qualification TLAA Demonstration

Commodity Type:	Pilot Light
Specific Description:	General Electric CR104L Pilot Light
Location:	Outside Containment
QDP:	Unit 1 QDP 67D
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The General Electric CR104L pilot light assemblies are used in the standby gas treatment system. Qualification is valid for the period of extended operation. The component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-73 Equipment Qualification TLAA Demonstration

Commodity Type:	Contactor
Specific Description:	Allen Bradley 702LP-AOD94 Magnetic Latch Contactor
Location:	Outside Containment
QDP:	Unit 1 QDP 67E
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Allen Bradley 702LP-AOD94 magnetic latch contactor in the standby gas treatment system control panels is qualified for 48 years when considering thermal and radiation. The thermal aging data do not support extending the qualified life to 60 years. For the Allen Bradley 702LP-AOD94 magnetic latch contactors, aging effects will be managed by the EQ program.

Figure 4.4-74 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	American Insulated Wire Corporation XHHW 600 V Panel Wire
Location:	Outside Containment
QDP:	Unit 1 QDP 67F
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The American Insulated Wire Corporation XHHX 600-V internal panel wire in the standby gas treatment system control panels is qualified for 40 years when considering thermal and radiation. The thermal aging data do not support extending the qualified life. For the American Insulated Wire Corporation XHHX 600-V internal panel wire, the aging effects will be managed by the EQ program.

Figure 4.4-75 Equipment Qualification TLAA Demonstration

Commodity Type:	Heater Elements
Specific Description:	Chromalox Heater Elements Models 50-47499 & 33-47499
Location:	Outside Containment
QDP:	Unit 1/2 QDP 68/75
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Chromalox heater elements (Models 50-47499 & 33-47499) are qualified for more than 60 years at the normal plant ambient temperatures. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification is valid for the period of extended operation.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-76 Equipment Qualification TLAA Demonstration

Commodity Type:	Electrical Penetration
Specific Description:	Conax Buffalo Corp. 7KPO-10001-01, -02, and -03
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 69/69
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation.

Conclusion:

The Conax Buffalo Corporation 7KPO-10001-01, -02, and -03 electrical penetration thermal aging data support a qualified life of 60 years. The penetrations are already qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The Conax Buffalo Corporation 7KPO-10001-01, -02, and -03 electrical penetration qualifications have been projected to the end of the period of extended operation.

Figure 4.4-77 Equipment Qualification TLAA Demonstration

Commodity Type:	Connectors
Specific Description:	EGS Quick Disconnects and Grayboot Connectors
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 70/76
Methodology:	10 CFR 50.59
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The EGS Quick Disconnect and Grayboot Connector qualified lives have been projected to the end of the period of extended operation for all currently installed applications.

For future applications at certain higher service temperatures (and falling short of qualification through the renewal term), the quick disconnects and grayboot connectors aging effects will be managed by the EQ program.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-78 Equipment Qualification TLAA Demonstration

Commodity Type:	Splice Tape
Specific Description:	United Controls International Model UCI-003XS
Location:	Inside/Outside Containment
QDP:	Unit 1/2, QDP 80/80
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The United Controls International Model UCI-003XS splice tape was recently qualified for new applications at Plant Hatch. The tape qualification is valid for the period of extended operation.

Figure 4.4-79 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Eaton (Samuel Moore) Instrumentation and Thermocouple Cables
Location:	Inside/Outside Containment
QDP:	Unit 2, QDP 17A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation. Criterion (iii): Manage the Aging Effects

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Eaton (Samuel Moore) instrumentation and thermocouple cables are qualified for 60 years at 187 °F. At localized higher service temperatures, the cable qualification was not projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program. The cable is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-80 Equipment Qualification TLAA Demonstration

Commodity Type:	Instrument and Thermocouple Cable
Specific Description:	Samuel Moore Type 1902 and 1952 EPDM/Hypalon Instrumentation and Thermocouple Cable
Location:	Outside Containment
QDP:	Unit 2 QDP 17B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The test data for the Samuel Moore Type 1902 and 1952 EPDM/Hypalon instrumentation and thermocouple cables support a qualified life in excess of 60 years at the normal operating temperatures. The cables are qualified to radiation levels geater than the worst-case 60-year total integrated dose, plus margin. The qualified lives of the Samuel Moore Type 1902 and 1952 EPDM/Hypalon instrumentation and thermocouple cables have been projected to the end of the period of extended operation.

Figure 4.4-81 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Cerro (Rockbestos) Low Voltage Instrumentation, Control and Power Cables
Location:	Outside Containment
QDP:	Unit 2, QDP 19
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Common component qualified lives have been reevaluated at maximum average (actual) service temperatures. The Cerro (Rockbestos) low voltage instrumentation, control and power cables have been projected to the end of the period of extended operation for all applications when considering thermal aging. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-82 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Switches
Specific Description:	General Electric SB-M and SB-1N Control Switches
Location:	Outside Containment
QDP:	Unit 2 QDP 21
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

Existing qualification test data for the General Electric SB-M and SB-1N control switches support a qualified life in excess of 60 years at the normal operating temperature. The worst-case 60-year total integrated dose plus margin for the control switch applications is less than the radiation damage threshhold for the nonmetallic materials in the components. The qualified lives of the General Electric SB-M and SB-1N control switches have been projected to the end of the period of extended operation.

Figure 4.4-83 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Control Centers
Specific Description:	General Electric 7700 Series DC MCCs
Location:	Outside Containment
QDP:	Unit 2 QDP 23
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation Criterion (iii): Manage the Aging Effects

Conclusion:

Southern Nuclear has demonstrated that the original qualification methodologies used for the DC MCC subcomponents were also used to project qualification to the end of the period of extended operation, with the possible exception of the molded case circuit breakers, thermal overloads, and the control power transformers. Aging effects for the molded case circuit breakers, thermal overloads, and the control power transformers will be manged by the EQ program.

Figure 4.4-84 Equipment Qualification TLAA Demonstration

Commodity Type:	Pressure Switch
Specific Description:	ITT Barton Model 580A-2 Differential Pressure Switch
Location:	Outside Containment
QDP:	Unit 2, QDP 34
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The ITT Barton Model 580A-2 differential pressure switch is used in the reactor building on the 158 ft elevation. The component already has a calculated qualified life greater than 60 years based on thermal aging. The component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. The test specimens were mechanically cycled during aging. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-85 Equipment Qualification TLAA Demonstration

Commodity Type:	Cable
Specific Description:	Boston Insulated Wire Low Voltage Control and Power Cables; and Coaxial Cable
Location:	Inside/Outside Containment
QDP:	Unit 2, QDP 44
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Boston Insulated Wire low voltage control and power cables are qualified for use inside and outside containment. The Boston insulated wire coaxial cables are qualified for use outside containment.

Common component qualified lives have been reevaluated at maximum average (actual) temperatures. The Boston insulated wire low voltage control and power cables; and coaxial cable qualifications have been projected to the end of the period of extended operation when considering thermal aging for all applications. The cables are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-86 Equipment Qualification TLAA Demonstration

Commodity Type:	Form Wound Motor
Specific Description:	Reliance Electric Model FNA-6856 and -6857
Location:	Outside Containment
QDP:	Unit 2, QDP 45A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Reliance Electric Model FNA-6856 and -6857 form wound motors are qualified to the requirements of 10 CFR 50.49 as replacements for original DOR equipment. At this time, there is one 10 CFR 50.49 Reliance Electric Model FNA-6856 installed.

Based on the date of installation for this motor, a 48-year qualification was required to project the qualified life to the end of the period of extended operation.

The qualified life of the installed motor was projected to the end of the period of extended operation based on thermal aging data. The motors are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

For any motors installed in the future, the original qualification is valid for the period of extended operation.

Note:

1. During testing, the motor was cycled through numerous start/stop cycles. This cycle aging will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-87 Equipment Qualification TLAA Demonstration

Commodity Type:	Control and Transfer Switches
Specific Description:	Electro Switch Series 20
Location:	Outside Containment
QDP:	Unit 2, QDP 46
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Electro Switch Series 20 control and transfer switches are qualified for 40 years in the 130 ft elevation of the reactor building and the HPCI room. The qualified life of these three switches could not be projected to the end of the period of extended operation. The aging effects will be managed by the EQ program.

Figure 4.4-88 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Element
Specific Description:	Rosemount 88-51-90 and 88-13-6
Location:	Outside Containment
QDP:	Unit 2, QDP 50
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Rosemount 88-51-90 and 88-13-6 temperature elements are qualified for use in the torus. The calculated qualified lives based on the thermal aging data are greater than 60 years, and the component is qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin. The existing qualification remains valid for the period of extended operation with minor qualitative document changes.

Figure 4.4-89 Equipment Qualification TLAA Demonstration

Commodity Type:	Fan Motor
Specific Description:	Farr Co. / Westinghouse Life-line 284T Frame Motor
Location:	Outside Containment
QDP:	Unit 2 QDP 71
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Farr Co. / Westinghouse Life-line 284T frame motor qualification is valid for the period of extended operation at the service temperature in the standby gas treatment system filter train room. The fan motor is qualified to a radiation level greater than the worst-case 60-year total integrated dose, plus margin.

Figure *4.4-90* *Equipment Qualification TLAA Demonstration*

Commodity Type:	Control Transformer
Specific Description:	Allen Bradley 1497-N20 Control Transformer (and attached X-277745 Fuse Block)
Location:	Outside Containment
QDP:	Unit 2 QDP 72A
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 1497-N20 control transformer (and attached X-277745 fuse block) in the standby gas treatment system already has a qualified life in excess of 60 years at normal operating temperature. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation with minor qualitative documentation changes.

Note:

1. Cycle aging performed during testing was based on the Regulatory Guide 1.52 requirement for 40-year life. Qualified life based on cycling will be determined prior to extending the qualified life beyond 40 years.

Figure 4.4-91 Equipment Qualification TLAA Demonstration

Commodity Type:	Molded Case Breakers
Specific Description:	Westinghouse HFB 3070L Molded Case Circuit Breaker
Location:	Outside Containment
QDP:	Unit 2 QDP 72B
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (ii): Requires Projection to the End of the Period of Extended Operation

Conclusion:

The Westinghouse HFB 3070L molded case circuit breaker qualification has been projected to the end of the period of extended operation at the normal operating temperature in the standby gas treatment system filter train room. The component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. Cycle aging performed during testing was based on Regulatory Guide 1.52 requirement for 40-year life. Qualified life based on cycling will be determined prior to extending the qualified life beyond 40 years.

Figure 4.4-92 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Starters
Specific Description:	Westinghouse A200 M2CAC Motor Starter and Interlocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72C
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse A200 M2CAC motor starter and interlocks in the standby gas treatment system control panels already have qualified lives in excess of 60 years at the normal operating temperature. The materials of construction are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Westinghouse A200 M2CAC motor starter and interlock qualifications remain valid for the period of extended operation.

Figure 4.4-93 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relay
Specific Description:	Westinghouse Type AN Overload Relay with Heater Elements
Location:	Outside Containment
QDP:	Unit 2 QDP 72D
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AN overload relay with heater elements in the standby gas treatment system control panels have qualified lives in excess of 60 years at the normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. The thermal overloads were cycled during testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-94 Equipment Qualification TLAA Demonstration

Commodity Type:	Contactor
Specific Description:	Allen Bradley 702LP-BOD93 Magnetic Latch Contactor
Location:	Outside Containment
QDP:	Unit 2 QDP 72G
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 702LP-BOD93 magnetic latch contactor used the standby gas treatment system control panel has a qualified life in excess of 60 years. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. Cycle aging performed during testing was based on the Regulatory Guide 1.52 requirement for 40-year life. This cycle aging issue will be reevaluated prior to extending the qualified life beyond 40 years.

Figure 4.4-95 Equipment Qualification TLAA Demonstration

Commodity Type:	Terminal Blocks
Specific Description:	Buchanan 211 Terminal Blocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72H
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Buchanan 211 terminal blocks in the standby gas treatment system control panels have qualified lives in excess of 60 years at normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Buchanan terminal block qualification remains valid for the end of the period of extended operation.

Figure 4.4-96 Equipment Qualification TLAA Demonstration

Commodity Type:	Circuit Breakers
Specific Description:	Telemecanique (Imperial) EF3-B070 Circuit Breaker
Location:	Outside Containment
QDP:	Unit 2 QDP 72J
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The Telemecanique (Imperial) EF3-B070 circuit breakers in the standby gas treatment system control panels are qualified for 40 years. The thermal aging data do not support extending the qualified life to 60 years. The Telemecanique (Imperial) EF3-B070 circuit breaker aging effects will be managed by the EQ program.

Figure 4.4-97 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses
Specific Description:	Bussmann Type FNM-5 Dual Element Time Delay Fuse
Location:	Outside Containment
QDP:	Unit 2 QDP 72K
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Bussmann Type FNM-5 dual element time delay fuses in the standby gas treatment system control panels have qualified lives in excess of 60 years at normal operating temperature. The materials of construction for these components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Bussmann Fuse qualification remains valid for the period of extended operation.

Figure 4.4-98 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses and Fuseblocks
Specific Description:	Bussmann 4482 Fuse Blocks and Bussman AGS and AGC Fuses
Location:	Outside Containment
QDP:	Unit 2 QDP 72L
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation (Fuses) Criterion (iii): Manage the Aging Effects (Fuse Blocks)

Conclusion:

The Bussmann 4482 fuse blocks in the standby gas treatment system control panels are qualified for 50 years. The thermal aging data does not support extending the qualified life to 60 years. The aging effects will be managed by the EQ program.

The Bussman AGS and AGC fuse qualification is valid for the end of the period of extended operation when considering thermal aging data.

The components are qualified to radiation levels greater than the worst-case 60-year total integrated dose, plus margin.

Figure 4.4-99 Equipment Qualification TLAA Demonstration

Commodity Type:	Pilot Light
Specific Description:	Allen Bradley 800H and 800T Pilot Lights
Location:	Outside Containment
QDP:	Unit 2 QDP 72N
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Allen Bradley 800H and 800T pilot light assemblies in the standby gas treatment system have a qualified life in excess of 60 years at the normal operating temperature. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The Allen Bradley 800H and 800T pilot light qualification remains valid for the period of extended operation.

Figure 4.4-100 Equipment Qualification TLAA Demonstration

Commodity Type:	Internal Panel Wire
Specific Description:	American Insulated Wire Corporation and Triangle Wire Company XHHW 600-V Panel Wire
Location:	Outside Containment
QDP:	Unit 2 QDP 72O
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The American Insulated Wire Corporation and Triangle Wire Company XHHX 600-V internal panel wire in the standby gas treatment system control panels has a calculated qualified life in excess of 60 years at the normal operating temperature. The wire is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The American Insulated Wire Corporation and Triangle Wire Company XHHX 600-V internal panel wire qualification remains valid for the period of extended operation.

Figure 4.4-101 Equipment Qualification TLAA Demonstration

Commodity Type:	Control Relays
Specific Description:	Allen Bradley Relays (See Below)
Location:	Outside Containment
QDP:	Unit 2, QDP 72P
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (iii): Manage the Aging Effects

Conclusion:

The following Allen Bradley control relay models are qualified for use in the standby gas treatment system filter train room of the 185 ft elevation of the reactor building:

- 700-P with 120 VAC coil
- 700-P with 600 VAC coil
- 700DC-P with 125 VDC coil
- 700-N with 120 VAC coil
- 700DC-N with 125 VDC coil
- 700-NA40 Front Deck

The Allen Bradley control relays are qualified for 50 years, with thermal aging limiting the qualified life. The qualified life cannot currently be projected to the end of the period of extended operation, and the aging effects will be managed by the EQ program.

Figure 4.4-102 Equipment Qualification TLAA Demonstration

Commodity Type:	Motor Starters and Electrical/Mechanical Interlocks
Specific Description:	Westinghouse A200, A201, and A210 Motor Starters; and Type J Auxiliary Contacts
Location:	Outside Containment
QDP:	Unit 2, QDP 72Q
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (ii): Projection to the End of the Period of Extended Operation

Conclusion:

The Westinghouse A200, A201, and A210 motor starters; and Type J auxiliary contacts are qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualified life based on thermal aging has been projected to the end of the period of extended operation. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Note:

1. Mechanical aging was performed with 12 VDC and 20-amp loading. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-103 Equipment Qualification TLAA Demonstration

Commodity Type:	Thermal Overload Relays with Heaters
Specific Description:	Westinghouse Type AN Relay with FH Series Heater Element
Location:	Outside Containment
QDP:	Unit 2, QDP 72R
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AN relay with FH series heater element is qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualified life based on thermal aging is greater than 60 years, and the components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. The qualification remains valid for the period of extended operation.

Note:

1. Cycle aging was performed during testing. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-104 Equipment Qualification TLAA Demonstration

Commodity Type:	Fuses
Specific Description:	Bussmann Types AGS and AGC
Location:	Outside Containment
QDP:	Unit 2, QDP 72S
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Bussmann Types AGS and AGC fuses are qualified for use in the standby gas treatment system filter train room at the 185 ft elevation of the reactor building.

The qualification is by test and material analysis and is valid through the period of extended operation when consdiering thermal aging. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin.

Figure 4.4-105 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Models 27121-0-325 and 27121-0-190
Location:	Outside Containment
QDP:	Unit 2 QDP 73
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Model 27121 thermoswitches are qualified for more than 60 years at the normal plant ambient temperatures. The components are qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. The vendor performed operational cycling during the qualification test program. Evaluation of the vendor's cycling data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-106 Equipment Qualification TLAA Demonstration

Commodity Type:	Temperature Switches
Specific Description:	Fenwal Models 18021-0
Location:	Outside Containment
QDP:	Unit 2, QDP 73A
Methodology:	10 CFR 50.49
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The Fenwal Model 18021-0 temperature switch is qualified for use in the standby gas filter train room at the 185 ft elevation of the reactor building. The switch is qualified for greater than 60 years at the normal design temperature, and is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. The vendor performed operational cycle aging during the qualification test program. Evaluation of the data shows that the qualification specification requirement for product performance was met. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be reevaluated.

Figure 4.4-107 Equipment Qualification TLAA Demonstration

Commodity Type:	Flow Switch
Specific Description:	McDonnell & Miller FS7-4V Flow Switch
Location:	Outside Containment
QDP:	Unit 2 QDP 74
Methodology:	DOR Guidelines
TLAA Demonstration Option:	Criterion (i): Valid for the Period of Extended Operation

Conclusion:

The McDonnell & Miller FS7-4V flow switches in the standby gas treatment system have a qualified life in excess of 60 years at the normal operating temperature. This component is qualified to radiation levels greater than the 60-year total integrated dose, plus margin. Qualification remains valid for the period of extended operation.

Note:

1. Before extending qualified lives beyond the current operating license term, qualified life limitations due to cycle aging will be evaluated.

4.5 CONTAINMENT PENETRATION PRESSURIZATION CYCLES

Southern Nuclear identified one containment penetration structural analysis for Plant Hatch that assumed a number of pressurization cycles for 40 years. This calculation was determined to meet all six criteria and, therefore, is a TLAA. The architect engineer performed the structural analysis to provide the design basis for the acceptability of using backing rings for certain types of pipe-to-penetration welds. The effect of the pressurization cycles on the calculation results is minimal. The calculation has been extended to 60 years of operation without change to plant equipment {demonstration through Criterion (ii) of 10 CFR 54.21(c)(1)}.

4.6 REACTOR VESSEL TLAAS

GE reports prepared for Southern Nuclear identify two TLAAs relating to 10 CFR 50 Appendix G requirements for fracture toughness (Section IV). These two requirements pertain to the effects of radiation embrittlement. Another TLAA involves the BWR Vessel and Internals Project (BWRVIP) request for inspection relief of circumferential welds. For Plant Hatch, Southern Nuclear has determined that 54 effective full-power years of reactor operation will carry the reactor vessel through the period of extended operation.

4.6.1 EQUIVALENT CHARPY UPPER-SHELF ENERGY MARGIN ANALYSIS

GE performed an update to the NRC-approved upper shelf energy (USE) equivalent margins analysis (Ref.18). This updated analysis incorporates the effects of irradiation for 54 effective full-power years (EFPY). The updated analysis determines that the generic materials considered will maintain the margins for USE required by 10 CFR 50 Appendix G.

GE reviewed the updated generic analyses with respect to applicability for the Plant Hatch license renewal term. This review is documented in an evaluation performed by GE (Ref. 17). GE determined that the generic analyses are applicable and that, for 54 EFPY, the critical materials would retain sufficient USE to satisfy 10 CFR 50 Appendix G requirements.

4.6.2 NIL-DUCTILITY REFERENCE TEMPERATURE ADJUSTMENTS

GE reevaluated the reduction in fracture toughness of the reactor vessel components due to neutron embrittlement and has determined that the analysis of embrittlement in the belt-line region of the core is a TLAA. The core belt-line region consists of bounding vessel locations adjacent to the active fuel where the neutron fluence will cause a shift in the reference temperature for the nil-ductility point (RT_{NDT}) of the materials.

GE performed a specific analysis for Plant Hatch (Ref. 11) using the criteria defined in the generic analysis (Ref. 18). The GE analysis for Plant Hatch considers the effect of neutron embrittlement for the extended 60-year term by considering 54 EFPY. The analyses include new sets of reactor operating pressure and temperature curves. The results of the analysis indicate that for both units, the adjusted reference temperature for nil-ductility will be less than the 10 CFR 50 Appendix G requirement of 200 °F.

4.6.3 CIRCUMFERENTIAL WELD INSPECTION RELIEF

The BWRVIP provided the technical bases supporting the elimination of RPV circumferential welds from the inservice inspection programs for BWRs as discussed in BWRVIP-74 (Ref. 18). These technical bases are approved for the current license term and are applicable to Plant Hatch. Southern Nuclear must make a plant-specific submittal requesting relief demonstrating how the technical bases were applicable to Plant Hatch.

Appendix E of the NRC's Safety Evaluation Report (SER) for BWRVIP-05 (Ref. 19) documents an evaluation of the impact of license renewal from 32 EFPY to 64 EFPY on the conditional probability of vessel failure. The SER reports that the frequency of cold overpressurization events results in a total vessel failure probability of approximately 5×10^{-7}. The SER conservatively evaluates an operating period of 10 EFPY greater than what is realistically expected for a 20-year license renewal term, i.e., 48 to 54 EFPY. Therefore, this analysis provides a basis for BWRVIP-05 to be approved as a technical alternative from the current inservice inspection requirements of ASME Section XI for volumetric examination of the circumferential welds as they may apply in the license renewal period.

If RPV circumferential weld examinations are still required by ASME Section XI at the point Plant Hatch enters the period of extended operation, Southern Nuclear will submit a specific request for approval of a technical alternative to the Code for Plant Hatch. In this submittal, Southern Nuclear will show that:

- At the expiration of the renewal period, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds given in Appendix E of the SER, and
- Southern Nuclear has implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the NRC SER.

For the purposes of this application, a summary of the demonstration that these two criteria are met follows:

In demonstration that criteria in the first bulleted item above has been satisfied, Southern Nuclear has reevaluated the probability of failure of the welds given the longer operating term associated with a renewed license. In keeping with the guidance of the BWRVIP, (Ref. 18), Southern Nuclear has recalculated the USE and the RT_{NDT} at the end of the renewed license (EOL) for the critical regions of the vessel. The calculations show that the remaining USE margin and the shift in the RT_{NDT} are both still acceptable per the 10 CFR 50 Appendix G requirements. Therefore, the probability of failure of the welds is less than the SER limit.

In demonstration that criteria in the second bulleted item above has been satisfied, Southern Nuclear has in place sufficient procedural control over operations and tests such that the likelihood of the occurrence of low temperature overpressure (LTOP) events is minimized. These procedures are reinforced through normal, periodic, operator training. The procedures and training will be maintained through the extended license term. Southern Nuclear's December 2, 1998, response to Generic Letter 98-05 contains details of the specific procedural controls and training.

Therefore, the basis for eliminating RPV circumferential weld examinations from the ISI Program is not affected by operation of the plant for 60 years. Hence, for License Renewal, the subject TLAAs for RPV circumferential weld examination remain valid for the extended period of operation {demonstration through Criterion (ii) of 10 CFR 54.21 (c)(i)}.

4.7 MAIN STEAM ISOLATION VALVES OPERATING CYCLES

The Plant Hatch FSARs contain statements with regard to the design of the MSIVs for the current license term. Southern Nuclear analyzed these statements for TLAA status. The Unit 2 FSAR paragraph 5.5.5.1, states the following (with a similar reference in the Unit 1 FSAR, subsection 4.6.3):

"The design objective for the valve is a minimum 40-year service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter." (Ref. 20)

The FSAR statement refers to mechanical cycles of the valve. Cycling of the valve will lead to wear of the valve disc and valve seat. The wear will accumulate over time (2,050 cycles are assumed in the FSAR statement for 40 years). The statement therefore meets the criteria of a TLAA. However, this kind of wear due to operation of the valve will lead to performance degradation, discoverable through normal leakage monitoring testing. Excessive leakage would lead to refurbishment or repair of the valve seat and disc, as necessary. Once maintenance is performed, the service life of the valve is restored. The components that would experience the wear that the FSAR statement describes are active parts of the valve assembly and would, therefore, not be subject to an aging management review. However, since the aging effect is readily discoverable through normal Technical Specification surveillance testing and repairable maintenance, the TLAA is demonstrated through existing maintenance and surveillance procedures {demonstration through Criteria (iii) of 10 CFR 54.21(c)(1)}.

4.8 GENERAL REFERENCES

1. H.L. Sumner to NRC Document Control Desk, December 2, 1998, "Reactor Pressure Vessel Shell Welds Examination."
2. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Section A.3.
3. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Paragraphs 3.9.2.1 and 6.3.2.2.1.
4. USNRC Regulatory Guide 1.46, Revision 0, "Protection Against Pipe Whip Inside Containment," Withdrawn August 11, 1985.
5. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Subsection 4.2.5.
6. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Paragraph 5.4.6.4.
7. Structural Integrity Associates Report Number SIR-99-078, Revision A, "Development of Class 1 Piping Fatigue Formulas and Fatigue Usage Estimates for the Hatch Nuclear Power Plant, Units 1 and 2," June 1999.
8. "Hatch Units 1 and 2 Torus Fatigue Analysis Report, REA HT-98674 Response"; Revision 0; Southern Company Services, Inc.; Nuclear Engineering and Regulatory Support; April 1999.
9. USNRC Generic Letter 89-013, "Service Water System Problems Affecting Safety-Related Equipment," July 1989.
10. USNRC Generic Letter 90-005, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping," June 1990.
11. GENE B11-00833-00-01, "Plant Hatch Reactor Pressure Vessel Aging Management Report," General Electric Company, November 1999 (GE Proprietary).
12. Edwin I. Hatch Final Safety Analysis Report, Unit 1, Section 7.16.
13. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Section 3.11.
14. EPRI TR-104873, "Methodologies and Processes to Optimize Environmental Qualification Replacement Internals," February 1996.
15. NUREG/CR-6384, "Literature Review of Environmental Qualification of Safety-Related Electric Cables," April 1996.
16. Plant Hatch Specification SS-2102-238, Revision 7, "Environmental Qualification Requirements for Safety Related Class 1E Electrical Equipment, Components, and Instrumentation," November 13, 1997.
17. GENE B11-00827-00-01, "Plant Hatch Units 1 and 2 Reactor Pressure Vessel Pressure/Temperature Limits License Renewal Evaluation," General Electric Company, March 1999.
18. EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999.
19. "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)," USNRC, July 28, 1998.
20. Edwin I. Hatch Final Safety Analysis Report, Unit 2, Section 5.5.5.1.
21. B. D. Frew to C. R. Pierce, letter dated September 15, 1999, "Corrosion Allowance for Hatch 1 and 2 Vessel/Piping Systems," BDF 9912, DRF B11-00827.

Appendix A

FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

CONTENTS

Introduction

The program and activity descriptions presented in Appendix A to the License Renewal Application represent the Plant Hatch commitments for managing aging of the in-scope systems, structures and components during the period of extended operation. These descriptions, as modified and approved during the licensing process, will be incorporated into a new Chapter 18 in the Unit 2 Final Safety Analysis Report following issuance of the new Operating License.

Other changes to the Final Safety Analysis Report, or other licensing basis documents, may be required due to the addition of the new Chapter 18, but not as a direct result of, or part of aging management. Southern Nuclear anticipates making such changes in concert with, but independent of, the addition of Chapter 18 to the Final Safety Analysis Report.

Background

As part of the license renewal effort, Southern Nuclear must demonstrate to the Nuclear Regulatory Commission that the aging effects determined to be applicable to Plant Hatch are adequately managed during the renewal term.

In many cases, existing programs and activities were found adequate for managing aging in the renewal term. In some cases, aging management reviews revealed that programs or activities required some degree of enhancement to adequately manage aging. Lastly, a number of new inspections were developed to provide objective evidence that aging was, in fact, being adequately managed by the credited programs and activities. The scope of these programs and activities for license renewal is determined by the scope of components and application of programs and activities as defined within the license renewal application and subsequent updates under 10 CFR 54.37(b).

Programs and Activities Credited for Managing Aging in the Renewal Term

It is important to note that only a portion of certain programs or activities may be required to manage aging during the renewal term. Accordingly, only the portion to which a commitment is made in this section is credited for license renewal. The systems, structures and components within the scope of license renewal are those within the evaluation boundaries.

Further, multiple programs or activities may be credited to manage aging in a single system, structure or component. Conversely, there are also cases where one program or activity may manage the effects of aging in multiple systems.

Except where otherwise stated, the portions of programs and activities credited for aging management are applicable to both units. Each management method presented in this section will be characterized as one of the following:

- **Existing Program (Activity):** A current program or activity that will continue to be implemented during the extended license period as shown in Appendix A of the License Renewal Application.
- **Enhanced Program (Activity):** A current program or activity that will be modified to manage aging during the extended license period. Enhancements will be implemented as shown in Appendix A of the License Renewal Application.

- **New Program (Activity):** A program or activity that does not currently exist, which will manage aging during the extended license period. These programs or activities will be implemented for the extended license period as shown in Appendix A of the License Renewal Application.

Characterization of a program or activity as new or existing is self-explanatory. For enhanced programs or activities, the substance of the enhancement is summarized in the text.

Time-Limited Aging Analyses

The Rule requires that time limited aging analyses (TLAA) be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40 year operating life of the plant. In addition, the Rule requires that any exemptions, based on TLAAs, be idenitified and analyzed to justify extension of those analyses through the renewal term.

TLAA evaluations for Plant Hatch included those calculations and analyses that met all six criteria of the Rule, specifically, those calculations or analyses that:

- Involved systems, structures, and components (SSCs) within the scope of license renewal;
- Considered the effects of aging;
- Involved time-limited assumptions defined by the licensed operating term at the time of license renewal application;
- Were determined to be relevant in making a safety determination;
- Involved conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated by the Rule; and
- Were contained or incorporated by reference in the licensing basis at the time of application for renewal.

Summary descriptions of TLAAs are provided in section A.4.

A.1 EXISTING PROGRAMS AND ACTIVITIES

Mitigating aging in a boiling water reactor (BWR) is heavily reliant on effective chemistry control and periodic inspection. These activities have been continuously refined at Plant Hatch as new information and techniques have become available.

Consequently, a significant portion of aging management during the renewal term will rely upon existing chemical control and inspection techniques that have evolved throughout the life of the plant, and been proven effective in the initial license term. Other existing programs described in this section are the result of long standing regulatory oversight and Southern Nuclear's involvement in industry improvement efforts.

A.1.1 REACTOR WATER CHEMISTRY CONTROL

A.1.1.1 Description

Reactor water chemistry control is a major part of the overall chemical control strategy for Plant Hatch. It is a mitigating activity designed to maintain structural integrity of plant systems and components by controlling fluid purity and composition.

By controlling water chemistry in the reactor coolant system and other non-inscope systems such as the condensate/feedwater cycle and the reactor water cleanup (RWCU) system, Plant Hatch reduces intergranular stress corrosion cracking (IGSCC) in reactor cooling system piping and reactor internals. Chemistry control also minimizes irradiation-assisted stress corrosion cracking (IASCC) and fuel cladding corrosion. Finally, water chemistry control helps decrease flow-accelerated corrosion (FAC) in the reactor coolant system, as well as balance of plant systems.

The principal elements of reactor water chemistry control are regular sampling, results analysis and, when applicable, chemistry modification. These activities are further supported by trending, tracking, and regular evaluations.

The reactor coolant, condensate, and feedwater systems that normally supply reactor coolant makeup are closely monitored, and regularly sampled and analyzed during all modes of plant operation.

A.1.1.2 Sample Size and Frequency

Reactor water sample frequencies and limits are operating mode dependent. Sample sizes vary in accordance with specific circumstances. The sample parameters and frequencies for each operating mode are specified in plant procedures.

As with reactor water, the specific condensate and feedwater parameters monitored, along with the sample frequencies, vary depending on the plant operational mode.

A.1.1.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria for reactor water chemistry control are based upon EPRI BWR water chemistry guidelines.

A.1.1.4 Aging Effects Requiring an Aging Management Program

The aging effects managed by reactor water chemistry control are cracking and loss of material.

Loss of material and cracking are the aging effects mitigated by reactor water chemistry control.

A.1.2 CLOSED COOLING WATER CHEMISTRY CONTROL

A.1.2.1 Description

Closed cooling water (CCW) chemistry control is a mitigating activity intended to maintain structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition.

The in-scope piping and components for license renewal are limited. Included are the section of reactor building closed cooling water (RBCCW) piping that serves the reactor recirculation pump motor bearings and seal coolers inside primary containment, and the primary containment chilled water (PCCW) piping that serves the Unit 2 Drywell Coolers.

The principal elements of CCW chemistry control are chemical additions, regular sampling, results analysis and, when applicable, chemistry modification.

- Chemicals are added to the RBCCW system to inhibit the corrosion process. RBCCW corrosion is monitored by diverting a small amount of flow through a coupon rack in a test loop. Sample coupons are examined periodically to verify the effectiveness of the corrosion inhibitor.
- Biocides are used to control microbiological growth. Chemistry determines which type of microbiocide should be added to the system to ensure that the types of microbiocides used are rotated.

Data are reviewed, and trend analysis is performed. Engineering personnel assist in performing evaluations of the structural integrity of the in-scope plant systems. When necessary, chemistry modification is performed.

A.1.2.2 Sample Size and Frequency

Sampling, operational guidelines, type of treatment, and frequency of analysis are determined by the prevailing fluid conditions.

A.1.2.3 Industry Codes, Standards, and Acceptance Criteria

The framework for CCW chemistry control at Plant Hatch is based upon the guidance provided in EPRI closed cooling water chemistry guidelines. Acceptance criteria contained therein are reflected in plant procedures.

A.1.2.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by CCW chemistry control.

A.1.3 DIESEL FUEL OIL TESTING

A.1.3.1 Description

The Diesel Fuel Oil Testing Program includes activities to mitigate loss of material from diesel fuel oil storage and transfer components that could result from intrusion of water or other contaminants.

The Diesel Fuel Oil Testing Program applies to the emergency diesel generator fuel oil storage tanks, the emergency diesel generator fuel oil day tanks, and the associated transfer piping and components. It also covers the in-scope fire pump diesel fuel oil storage tanks and the associated piping and components.

Fuel oils in their pure form are nonaggressive and noncorrosive for all metals. However, water in fuel oil, naturally occurring contaminants, and fuel oil additives can produce a corrosive environment. Plant Hatch testing activities provide for detection of water or other contaminants before loss of material can threaten a component function. Program elements include sampling new fuel and periodic verification that the total particulate concentration is within acceptable limits.

To prevent introduction of contaminated oil into plant systems, new oil is sampled before off loading the delivery vehicle. An additive is introduced via the transfer hose during the off loading. When properly controlled, this additive minimizes the microorganisms necessary to induce microbiologically influenced corrosion (MIC).

The fire pump fuel oil storage tank and the emergency diesel generator fuel oil storage and day tanks are regularly checked for water in accordance with the FHA and Technical Specifications respectively. If water has accumulated, it is removed.

A.1.3.2 Sample Size and Frequency

Sample sizes and frequencies vary depending upon the circumstances and components being sampled. The significant frequencies and sample sizes are outlined below.

Stored oil total particulate concentration, and water and sediment concentration are sampled once per quarter. Regular surveillance to check for and remove water is completed semi-annually.

A.1.3.3 Industry Codes, Standards and Acceptance Criteria

New oil total particulate concentration sampling prior to off load is conducted using the guidance provided in ASTM D-2276, Method A-2 or A-3, Standard Test Method for Particulate Contaminant in Aviation Fuel.

Other standards applicable to the plant Diesel Fuel Oil Testing Program include, but are not limited to, ASTM D 975-74, Standard Classification of Diesel Fuel Oils; ASTM D 1796-83, Section 5.01, Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (laboratory procedure); and ASTM D 270-65, Part 18, Standard Method of Sampling Petroleum and Petroleum Products.

Total particulate concentration for stored diesel fuel oil is required by Technical Specifications 5.5.9.b, to be less than 10 mg/l. As indicated in SR 2.3.2.b in Appendix B of the FHA, the same acceptance criteria applies to the fire diesel fuel oil storage tank.

A.1.3.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by diesel fuel oil testing.

A.1.4 PLANT SERVICE WATER AND RHR SERVICE WATER CHEMISTRY CONTROL

A.1.4.1 Description

Plant service water (PSW) and residual heat removal service water (RHRSW) chemistry control activities are intended to mitigate aging in system piping and components by controlling fluid composition.

The PSW and RHRSW chemistry control activities are applicable to all system piping/ components within the scope of license renewal, located downstream of the chemical injection points.

The service water system is treated with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) as required.

A.1.4.2 Sample Size and Frequency

Chlorination and bromination are coordinated with the periodic operation of RHRSW to maximize chemical treatment. Normally, each unit's PSW system is chlorinated and brominated separately for 6-12 hours per unit, per day. However, changes in conditions may cause more or less chlorination to be necessary.

A.1.4.3 Industry Codes, Standards and Acceptance Criteria

Since PSW and RHRSW discharge to the circulating water flume, and the flume discharges to the river, chemicals cannot be added at a rate that would cause the National Pollutant Discharge Elimination System (NPDES) permit limit to be exceeded. Although environmental requirements may not necessarily be considered codes or standards, discharged measurable chlorine, free available oxidant, and total residual oxidant levels are governed by the Hatch NPDES permit and, therefore, become the defacto limits to chemistry control in PSW and RHRSW.

A.1.4.4 Aging Effects Requiring an Aging Management Program

Loss of material and flow blockage are the aging effects mitigated by PSW and RHRSW chemistry control.

A.1.5 FUEL POOL CHEMISTRY CONTROL

A.1.5.1 Description

Fuel pool chemistry control activities are intended to mitigate aging in the fuel pool liner and associated components by controlling fluid purity and composition.

The plant fuel pool chemical control activities are applicable to the stainless steel liners for the spent fuel pool, spent fuel pool plugs, spent fuel pool gate, and the refueling canal. Other stainless steel material includes the spent fuel pool storage racks and miscellaneous steel inside the spent fuel pool. Aluminum components include the seismic restraints for the spent fuel storage racks.

The principal elements of the fuel pool chemistry control activities are regular sampling, results analysis and, when applicable, chemistry modification. All chemistry sampling and analysis are done in accordance with approved plant procedures and instructions.

A.1.5.2 Sample Size and Frequency

The fuel pool water is sampled regularly for conductivity, pH, chlorides and sulfates, filterable solids and total organic carbons. The sample frequencies contained in plant procedures are based upon the applicable portions of EPRI guidelines or other updated industry guidance, as they pertain to Plant Hatch.

A.1.5.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria contained in plant procedures are based upon EPRI guidelines or other updated industry guidance, as they pertain to Plant Hatch.

A.1.5.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by fuel pool chemistry control.

A.1.6 DEMINERALIZED WATER AND CONDENSATE STORAGE TANK CHEMISTRY CONTROL

A.1.6.1 Description

Demineralized water and condensate storage tank (CST) chemistry control activities are intended to mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. The principal elements of these activities are regular sampling, results analysis and, when applicable, chemistry modification.

The demineralized water system proper (P21) is not within the scope of license renewal. However, several systems and components that receive makeup water from the demineralized water storage tank, including the CST, are within the scope of license renewal. Thus, demineralized water storage tank and CST chemistry controls are an important part of overall aging management at Plant Hatch.

A.1.6.2 Sample Size and Frequency

The demineralized water storage tank influent and effluent are monitored. The effluent is sampled weekly for conductivity, pH, silica, chloride, sulfate and total organic carbon. These same parameters are also analyzed for the CST, along with total gamma activity.

A.1.6.3 Industry Codes, Standards and Acceptance Criteria

Plant procedures specify the acceptance criteria for the demineralized water storage tank and CST parameters listed in Section A.1.6.2.

A.1.6.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by demineralized water storage tank and CST chemistry control.

A.1.7 SUPPRESSION POOL CHEMISTRY CONTROL

A.1.7.1 Description

Suppression pool chemistry control activities are intended to mitigate aging in components exposed to the suppression pool water by controlling fluid purity and composition in the pool.

Various components exposed to the suppression pool water are within the scope of license renewal. These include components of the residual heat removal (RHR), core spray (CS), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems and a portion of the safety relief valve (SRV) tailpipes. Also included are the suppression chamber shell, vent header, deflectors and supports, downcomers and braces, and suppression chamber interior platform support.

The principal elements of suppression pool chemistry control activities are regular sampling and results analysis. All chemistry sampling and analysis are done in accordance with approved plant procedures and instructions.

A.1.7.2 Sample Size and Frequency

The suppression pool is sampled regularly for conductivity (zinc corrected), chlorides, sulfates, zinc, and total organic carbons. The sample frequencies contained in plant procedures are based upon the applicable portions of EPRI guidelines or other updated industry guidance.

A.1.7.3 Industry Codes, Standards and Acceptance Criteria

The acceptance criteria contained in plant procedures are based upon EPRI guidelines or other updated industry guidance, as they pertain to chemistry control at Plant Hatch.

A.1.7.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated by suppression pool chemistry control.

A.1.8 CORRECTIVE ACTIONS PROGRAM

A.1.8.1 Description

The Corrective Actions Program is briefly described in chapter 17 of the Unit 2 Final Safety Analysis Report (FSAR). This process will be effective for correcting potential age related degradation that may be discovered during the renewal term.

The primary vehicle for initiating corrective action at the plant is the condition reporting process. Existing procedures include the necessary forms and instructions for reporting potential problems related to aging management of the systems, structures and components (SSCs) within the scope of license renewal.

Significant conditions adverse to quality require initiation of a special report. Significant occurrences are investigated to determine root cause, and actions are taken to preclude recurrence. Forms and guidance for root cause analysis are provided in plant procedures or guidelines.

Plant procedures also specify the method for documenting, tracking and correcting reported conditions. Condition reports are analyzed for adverse trends by management. Adverse aging trends during the renewal term can be identified in this manner.

A.1.8.2 Sample Size and Frequency

The Corrective Actions Program applies to the systems, structures and components within the scope of license renewal.

A.1.8.3 Industry Codes, Standards and Acceptance Criteria

Corrective actions are part of the Quality Assurance (QA) Program, as required for the current license term under Criterion XVI of Appendix B to 10 CFR 50. This will continue to be applicable during the renewal term, as modified by the regulatory process.

A.1.8.4 Aging Effects Requiring an Aging Management Program

Each aging effect shown in this appendix is covered by the Corrective Actions Program.

A.1.9 INSERVICE INSPECTION PROGRAM

A.1.9.1 Description

The Inservice Inspection (ISI) Program is a condition monitoring program that provides for the implementation of ASME Section XI in accordance with the provisions of 10 CFR 50.55a at Plant Hatch. The ISI Program also includes augmented examinations required to satisfy commitments made by SNC (e.g., GL-88-01, NUREG-0619). The 10-year examination plan provides a systematic guide for performing nondestructive examination and pressure testing of passive components within the scope of license renewal. Plant Hatch is currently in the third 10-year inspection interval. The period of extended operation will include the fifth and sixth inservice inspection intervals.

The ISI Program provides examination methods and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for periodic pressure testing of those same components, along with repair, replacement and modification activities.

ASME Class 1, 2 and 3 (equivalent), and Class MC components are covered by ASME subsections IWB, IWC, IWD, and IWE, respectively. Subsection IWF covers supports, which are treated the same as the code class component they support.

Three types of inspection methods are used for inservice examination at Plant Hatch. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in IWA-2210. The three types of visual examinations used are designated VT-1, VT-2, and VT-3.

- VT-1 is used to determine the condition of the part, component, or surface examined, including cracks, wear, corrosion, erosion, or physical damage.
- VT-2 is used to locate evidence of leakage from pressure retaining components during a system pressure test.
- VT-3 is used to determine the general mechanical and structural condition of components and the associated supports such as verification of clearances, physical displacements, and loose or missing parts. This includes inspection for debris, corrosion, wear, erosion, or loss of integrity at bolted or welded connections.

Surface examinations are performed as defined in IWA-2220 to determine whether surface cracks or discontinuities exist. Volumetric examinations are performed as defined in IWA-2230 to locate discontinuities throughout the volume of material. These examinations may be conducted from the inside or outside surface of a component. Either radiographic (RT) or ultrasonic examination (UT) methods may be used.

A.1.9.2 Sample Size and Frequency

The extent and frequency of examinations for components subject to ASME Section XI requirements at Plant Hatch are based on the tables in Article 2500 of ASME Section XI Subsections IWB, IWC, IWD, IWE, and IWF.

A.1.9.3 Industry Codes, Standards, and Acceptance Criteria

For the third 10-year inspection interval, Plant Hatch uses the 1989 Edition of ASME Section XI for Class 1, Class 2, and Class 3 (equivalent) systems and components. For Class MC systems and components, Plant Hatch applies the 1992 Edition of ASME Section XI with the 1992 addenda. The acceptance standards used for inservice inspection are based on the tables in Article 2500 of ASME Section XI Subsections IWB, IWC, IWD, IWE, and IWF.

A.1.9.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, loss of preload, and loss of fracture toughness are the aging effects monitored by the ISI Program.

A.1.10 OVERHEAD CRANE AND REFUELING PLATFORM INSPECTIONS

A.1.10.1 Description

Plant crane and refueling platform inspections are condition monitoring activities conducted to verify structural integrity of all load bearing and operating components to assure safe operation. Crane and refueling platform inspection activities also satisfy the requirements of the Unit 1 Technical Requirements Manual which requires surveillance testing of the 5-ton hoist, and the crane/hoist used for handling fuel assemblies or control rods.

Inspection activities include a preoperational static inspection, preoperational dynamic inspection, operational inspection, maintenance inspection, and as required inspections. The overhead crane and refueling platform hoist, rigging, slings and lifting devices are visually inspected to ensure structural integrity. A trial lift of the spent fuel pool gate or an equivalent weight is also performed for each device performing this lifting function.

When cranes are in service, or prior to using standby cranes, detailed visual inspection of all wire rope is made to check for, among other things, general corrosion, kinks, and strand displacement. Hooks are visually inspected for cracks or distortion. Connections are checked for weld cracks and loose or missing bolts. Bridges, bridge rails, trolley and trolley rails are visually inspected for straightness and evidence of physical damage or cracking.

A.1.10.2 Sample Size and Frequency

All load bearing and crane operating components within the scope of license renewal are inspected. General visual inspections are performed monthly in accordance with plant procedures. Annual magnetic particle tests are performed on hooks. Overhead cranes are visually inspected daily when in use.

A.1.10.3 Industry Codes, Standards and Acceptance Criteria

Plant overhead crane and refueling platform inspection procedures were developed using ANSI B30.2.0-1976 and NUREG-0612. Inspection procedures for fuel handling equipment were developed using ANSI B30.9-1971, ANSI/ASME B30.10-1982, ANSI N14.6-1978 and NUREG-0612. Wire rope safety factors from ANSI B30.5 or SAE J959-1966 are applied to acceptance criteria.

End connections must not be severely corroded, cracked, bent, worn or improperly applied. Wire rope must be within the maximum reduction from nominal as stated in plant procedures. Any weld cracking requires performance of nondestructive testing. Loose bolts are replaced rather than tightened.

A.1.10.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by plant crane inspections.

A.1.11 TORQUE ACTIVITIES

A.1.11.1 Description

Torque activities are intended to mitigate loss of preload through use of proper torque techniques at Plant Hatch. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities.

Hardened steel washers may be used in conjunction with joint bolting, since they allow more of the applied torque to be translated to bolt stress, which provides the preload necessary for a tightly sealed joint. In joints subject to thermal or process load cycling, Belleville washers or extra-length bolting may be used to provide better response to the changing conditions caused by cycling.

Bolting threads and load bearing faces are lubricated with an approved thread lubricant immediately before assembly to allow the maximum torque to be translated to bolt stress. Leveling passes are performed using a calibrated torquing tool and continue until there is no rotational movement of the fasteners at the final torque value.

For any joint considered at high risk for leakage, as demonstrated by past performance or based on the judgment of the responsible supervision, leveling passes may be repeated at the final torque value after 24 hours. This may be done to compensate for gasket relaxation (creep) prior to putting the joint into service.

A.1.11.2 Sample Size and Frequency

The Plant Hatch torquing procedure was developed for use on pressure retaining systems, ASME Code piping, and other fasteners used in bolted joints where satisfactory torque values are not available in other approved plant documents.

A.1.11.3 Industry Codes, Standards and Acceptance Criteria

The torquing procedure was evaluated against the guidance contained in EPRI guidelines for degradation and failure of bolting in nuclear power plants.

Other codes and standards considered during development of the plant torquing procedure were ASME, Section VIII, Div. 1, App. 2; ASME, Section II, Specification for Carbon Steel Externally Threaded Standard Fasteners; ASTM Standards, Section 15, Volume 15.08, Fasteners; and ANSI B31.1.

A.1.11.4 Aging Effects Requiring an Aging Management Program

Loss of preload is the aging effect mitigated by torque activities.

A.1.12 COMPONENT CYCLIC OR TRANSIENT LIMIT PROGRAM

A.1.12.1 Description

The Plant Hatch Component Cyclic or Transient Limit Program is a surveillance program required by Technical Specifications. It is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components and the torus will remain within the ASME Code Section III fatigue limits, including the effects of a reactor water environment.

The plant fatigue cumulative usage factor (CUF) is calculated for four limiting high stress reactor pressure vessel (RPV) boundary components on each unit. The RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles have been shown by analysis to be the limiting components.

CUF is also calculated for the limiting location for the torus on each unit, and for nine locations within the Class 1 boundary. Class 1 monitoring includes the limiting locations on the reactor vessel equalizer, core spray, standby liquid control, feedwater, HPCI, RCIC, RWCU, and main steam piping for Unit 1. On Unit 2, the limiting locations are the residual heat removal, feedwater, primary steam condensate drainage, and main steam piping.

When CUF calculations project CUF to exceed 1.0 for the next operating cycle, engineering evaluations are performed to disposition the projection.

A.1.12.2 Sample Size and Frequency

Plant procedures require that the CUF for each of the limiting components on each unit be calculated at least once per operating cycle. Data may be collected at any time during the surveillance period.

A.1.12.3 Industry Codes, Standards and Acceptance Criteria

High fatigue usage components have been selected to be tracked by this program to assure that the plant will continue to meet the ASME Code, Section III, CUF design requirement value of 1.0.

A.1.12.4 Aging Effects Requiring an Aging Management Program

Cracking is the aging effect monitored by the Component Cyclic or Transient Limit Program.

A.1.13 PLANT SERVICE WATER AND RHR SERVICE WATER INSPECTION PROGRAM

A.1.13.1 Description

The Plant Service Water (PSW) and RHR Service Water (RHRSW) Inspection Program is a condition monitoring program. This program is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. Locations determined to be prone to corrosion are infrequently used piping, piping with low fluid velocity, small diameter piping, backing rings and socket welds. Locations prone to clogging include those prone to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, and low point drains.

Piping inspections may be performed using radiography testing (RT), ultrasonic testing (UT), depth gauges or pipe removal and analysis.

A.1.13.2 Sample Size and Frequency

The inspection frequencies are determined by evaluating the trends in wall thickness reduction. If the trend indicates that the pipe wall thickness might be reduced to the minimum allowable wall thickness value prior to completion of the next operating cycle, then the inspection frequency and lot size are adjusted. In all cases, at least one full operating cycle must be allowed to complete repairs prior to reaching the minimum pipe wall thickness.

A.1.13.3 Industry Codes, Standards and Acceptance Criteria

The PSW and RHRSW Inspection Program was developed using the edition of ASME, Section XI in the Inservice Inspection Program. Although not specifically codes or standards, the framework for the program is also based partially upon Generic Letter 89-13 and its supplements, and NUREG-1275, Volume 3, "Operating Experience Feedback Report – Service Water System Failures and Degradations".

Minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements and the piping specification drawings. The bases for the acceptance criteria are contained in the PSW and RHRSW Inspection Program procedures.

A.1.13.4 Aging Effects Requiring an Aging Management Program

Loss of material, flow blockage, cracking, and loss of heat exchanger performance are the aging effects monitored through the PSW and RHRSW Inspection Program.

A.1.14 PRIMARY CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A.1.14.1 Description

The Plant Hatch Primary Containment Leakage Rate Testing Program is a condition and performance monitoring program that ensures the structural integrity of primary containment through visual inspection and performance testing activities. Plant Hatch Technical Specifications require the implementation of the Primary Containment Leakage Rate Testing Program and the attendant written procedures.

This program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. This includes the steel primary containments, containment penetrations, and containment internal structures which perform a structural or pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive (CRD) removal hatches.

Type A tests are performed in accordance with ANSI/ANS 56.8 1994 and/or Bechtel Topical Report BN-TOP-1 and implemented through plant procedures. Type B and C tests are performed in accordance with ANSI/ANS 56.8-1994 and implemented through plant procedures.

A.1.14.2 Sample Size and Frequency

Test frequencies are determined in accordance with plant procedures. An as-found Type B or C test is performed prior to any maintenance, repair, modification, or adjustment activities that could affect the primary containment boundary's leak tightness.

A.1.14.3 Industry Codes, Standards and Acceptance Criteria

The Primary Containment Leakage Rate Testing Program is based upon Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995. ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirements," 1994, and NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J", July 26, 1995 are also used.

The primary containment leakage rate acceptance criteria for the Plant Hatch Primary Containment Leakage Rate Testing Program are specified in the Technical Specifications. The administrative limits assigned to each component are specified such that they are indicators of potential penetration degradation.

A.1.14.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by the Primary Containment Leakage Rate Testing Program.

A.1.15 BOILING WATER REACTOR VESSEL AND INTERNALS PROGRAM

A.1.15.1 Description

The Boiling Water Reactor Vessel and Internals Project (BWRVIP) is an association of utilities formed to focus on resolution of BWR vessel and internals issues. The BWRVIP Program was developed based on over 20 years of service and inspection experience and is focused on detecting evidence of component degradation well in advance of significant degradation.

For license renewal, the BWRVIP Program inspection and evaluation reports specifically addressed the internals relative to the requirements of the Rule. At the time of the Plant Hatch LRA, the NRC was continuing its review of these reports and issuing safety evaluation reports (SERs) to address license renewal.

The BWRVIP Program reviewed the function of each internal BWR component. For those internals that could impact safety, the BWRVIP Program considered the mechanisms that might cause degradation of such components and developed an inspection program that would enable degradation to be detected before the component function was adversely affected.

The reactor vessel internals requiring aging management within the scope of license renewal are the shroud, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. For Unit 1 only, the top guide is also included.

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable inspection and evaluation document, unless specific exception has been identified to the NRC.

SNC has evaluated the BWRVIP Program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV components, including the materials used for construction, are addressed by the BWRVIP Program inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP Program reports.
- The BWRVIP Program reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP Program reports bound the Hatch Units 1 and 2 design and operation.

A.1.15.2 Sample Size and Frequency

The frequency of examination varies for each component or subassembly. The frequency is based on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used. In cases where a component may be inspected using either visual or ultrasonic methods, the interval between examinations is shorter when visual methods are used.

A.1.15.3 Industry Codes, Standards, and Acceptance Criteria

The requirements of Section XI of the ASME Boiler and Pressure Vessel Code apply to attachments welded to the RPV, welded core support structures, and penetrations. In most cases, the BWRVIP Program is more appropriate than Section XI requirements for use on BWR internals.

The BWRVIP Program for internals subject to license renewal as implemented at Plant Hatch employs the BWRVIP Program criteria documented in the NRC SERs, except where specific exception has been identified to the NRC.

A.1.15.4 Aging Effects Requiring an Aging Management Program

Cracking is the aging effect managed by the BWRVIP Program.

A.1.16 WETTED CABLE ACTIVITIES

A.1.16.1 Description

Plant Hatch wetted cable activities provide for mitigating activities as well as condition monitoring activities. Plant Hatch wetted cable activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4 kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings.

In pull boxes where these in-scope cables are routed, water level is measured, recorded, and the pull boxes drained. Megger and polarization index (PI) testing are periodically performed. The cables are hipot tested when new terminations are made. This provides additional assurance that the cable insulation integrity is sound.

A.1.16.2 Sample Size and Frequency

Pull boxes are drained quarterly. Testing is performed on inscope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

A.1.16.3 Industry Codes, Standards and Acceptance Criteria

The activities described herein meet the intent of IEEE 43-1974, Recommended Practice for Testing Insulation Resistance of Rotating Machinery; and IEEE 95-1977, Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage.

Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and PI testing.

A.1.16.4 Aging Effects Requiring an Aging Management Program

Change in insulation resistance is the aging effect mitigated and monitored by the wetted cable activities.

A.1.17 REACTOR PRESSURE VESSEL MONITORING PROGRAM

A.1.17.1 Description

Reactor Pressure Vessel (RPV) Monitoring Program is an existing condition monitoring and surveillance program at Plant Hatch. It is based on detailed evaluation of the Plant Hatch Unit 1 and Unit 2 RPVs. The program is supported by an industry topical report for the license renewal period, BWRVIP-74, which is under review by the Nuclear Regulatory Commission (NRC) at the time of the license renewal application.

The RPV Monitoring Program covers the reactor vessel beltline shells, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles, and penetration seals. The core dP and standby liquid control nozzle, the support skirt and the closure studs, the core spray pipe, jet pump riser brace pad, and shroud support welds are also included.

RPV monitoring is accomplished through a combination of fatigue monitoring, code-required and augmented inspections, pressure tests, and surveillance material testing. RPV shell and head aging management is accomplished by performing ultrasonic examinations of the RPV vertical shell welds, periodic pressure tests with visual examination for leakage, and surveillance capsule testing. Plant Hatch uses an NRC approved technical alternative in lieu of ultrasonic testing of circumferential shell welds. This basis for the alternative is contained in the BWR reactor pressure vessel shell weld inspection recommendations, and associated supplements.

The Plant Hatch materials surveillance program may be altered prior to operation during the renewal period. The BWRVIP is developing an Integrated Surveillance Program (ISP) for all domestic operating BWRs as allowed by 10 CFR 50 Appendix H. The ISP will be provided to the NRC by BWRVIP for review and approval. Both Hatch RPVs are included in the program. However, existing analyses at the time of application show that operation to 60 years is acceptable.

SNC has evaluated the BWRVIP program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters, including temperature pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

A.1.17.2 Sample Size and Frequency

RPV vertical shell welds are examined once every 10 years. A pressure test of the RPV is conducted at the end of each refueling outage.

RPV nozzles and safe ends are examined as required by ASME Section XI or an augmented program, in accordance with the Plant Hatch ISI Program (Section A.1.9). This includes ultrasonic and surface examinations for nozzles 4 nominal pipe size (NPS) and larger, surface examination for nozzles less than 4 NPS. Pressure tests for the Class 1 boundary are performed at the conclusion of each refueling outage in accordance with ASME Section XI, Section IWB-5000.

A.1.17.3 Industry Codes, Standards, and Acceptance Criteria

RPV ultrasonic examinations and the pressure tests with the associated visual examinations will be conducted in accordance with ASME Section XI as part of the Inservice Inspection (ISI) Program that is required by 10 CFR 50.55a (see Section A.1.9). RPV surveillance capsule testing is required by 10 CFR 50 Appendix H. That testing provides data used to show that the criteria for fracture toughness of 10 CFR 50 Appendix G are satisfied.

Limits are imposed on pressure and temperature by 10 CFR 50 Appendix G. Pressure-Temperature limit curves have been prepared for Hatch Units 1 and 2 to allow operation up to 54 EFPY. Appendix G of 10 CFR 50 also contains requirements for Upper Shelf Energy (USE) to ensure adequate fracture toughness is maintained. USE calculations performed for Plant Hatch limiting beltline materials, using equivalent margins analysis, justify operation up to 54 EFPY.

Feedwater nozzles will be examined in accordance with ASME Section XI and the Plant Hatch NUREG-0619 Program (see Section A.1.9). The recirculation inlet nozzles and the feedwater nozzles are covered by the fatigue monitoring program (see Section A.1.12).

A.1.17.4 Aging Effects Requiring an Aging Management Program

Cracking and loss of fracture toughness are the aging effects monitored by the RPV Monitoring Program.

A.2 ENHANCED PROGRAMS AND ACTIVITIES

During the aging management reviews, Southern Nuclear found cases where opportunities existed for aging management improvements. While enhancements will serve to better manage aging at Plant Hatch, no cases were found where immediate action was required to maintain the license renewal functions.

The enhancements for the affected programs or activities are outlined in this section under the appropriate description. These enhancements may be implemented on or before the dates indicated under each description.

A.2.1 FIRE PROTECTION ACTIVITIES

A.2.1.1 Description

Fire protection activities are comprised of condition monitoring and performance monitoring activities. Fire protection activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. Through a defense-in-depth philosophy, the Fire Protection Program is designed to minimize both the probability and consequences of postulated fires.

The portion of the Plant Hatch fire protection activities credited for license renewal is that portion included in Appendix B of the Fire Hazards Analysis (FHA). It includes passive long-lived components in water based and gaseous fire suppression systems. Also included are the fire pump diesel fuel oil supply system (tanks and piping) and various fire rated assemblies.

The water-based fire protection header loop piping is flushed on a regular basis. The fire pump casings are visually inspected and operationally tested. Sprinklers are visually inspected and open-head sprinklers and nozzles are flow tested using air.

Fire water tank internals are inspected for localized and general pitting, average dry film thickness and general condition of the protective coating. Sizes and depth of pits are recorded. Interior surfaces are cleaned as required to facilitate inspection.

The fire pump diesel fuel oil supply and various gaseous fire suppression system components are visually inspected and performance tested. The in-scope fire-rated assemblies are also visually inspected periodically.

A.2.1.2 Sample Size and Frequency

The surveillance requirements and the associated frequencies are set forth in Appendix B of the FHA.

A.2.1.3 Industry Codes, Standards and Acceptance Criteria

The fire protection system at the plant was designed in accordance with the requirements of Nuclear Electric Insurance Limited (NEIL). The design was reviewed against the applicable NFPA codes, and the local codes and regulations applicable to Plant Hatch have been met.

A.2.1.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, flow blockage, and change in material properties in nonmetallic components are the aging effects monitored by fire protection activities.

A.2.1.5 Enhancements

Fire protection activities will be enhanced to include periodic inspection of water suppression system strainers which will be inspected for flow blockage and loss of material due to mechanisms such as corrosion.

Enhancements will be implemented by midnight August 6, 2014.

A.2.2 FLOW ACCELERATED CORROSION PROGRAM

A.2.2.1 Description

The Flow Accelerated Corrosion (FAC) Program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. Piping that may be susceptible to FAC is predicted using a model specifically developed for FAC analysis.

The FAC model predicts single- and two-phase flow-accelerated corrosion rates in piping, and calculates the time remaining until reaching the defined critical wall thickness. Large bore piping modeled for FAC includes the reactor feedwater piping. Several sections of piping are also inspected based upon industry experience.

Ultrasonic testing (UT) is used to detect wall thinning. Radiographic testing (RT) may be used in cases where UT is impractical (e.g., small-diameter piping). In certain cases, visual examinations (VT) from inside the piping may be performed, with followup UT contingent upon the VT results.

A.2.2.2 Sample Size and Frequency

Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical modeling results, pertinent industry events, and plant operating experience.

A.2.2.3 Industry Codes, Standards and Acceptance Criteria

The framework for the Plant Hatch FAC Program is based upon EPRI recommendations for effective flow-accelerated corrosion program. The equations used to derive wall thickness acceptance criteria are based upon the governing code of record for the piping.

A.2.2.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect monitored by the FAC Program

A.2.2.5 Enhancements

The enhanced examination methods and frequencies will be based on industry and plant-specific operating experience as opposed to computer modeling. Examinations to detect erosion, erosion corrosion, as well as FAC, will be performed as part of the enhanced program.

For both units, the Flow Accelerated Corrosion Program will be expanded to include additional piping for certain systems that are already included in the current program.

For Unit 2 only, portions of the radioactive decay holdup volume (main steam and steam line drains, and condensate drains) will also be included.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

A.2.3 PROTECTIVE COATINGS PROGRAM

A.2.3.1 Description

The Protective Coatings Program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance and inspection of protective coatings on selected components and structures.

A.2.3.2 Sample Size and Frequency

Protective coatings surveillance is normally performed once per operating cycle for Service Level I components. Other component surveillance is performed as determined by the protective coatings specialist, based upon trends and plant specific operating experience.

A.2.3.3 Industry Codes, Standards and Acceptance Criteria

Multiple codes and standards were considered in the development of the plant Protective Coatings Program. These include ANSI N5.12 – 1972, Protective Coatings (Paints) for the Nuclear Industry; ANSI N101.2 – 1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities; ASTM, Section 6, Volume 06.02, Paints-Products and Applications, Protective Coatings, Pipeline Coatings, and AWWA C209, American Waterworks Association Code for Cold Applied Tape Coatings.

Coatings application is not allowed to proceed until applicable solvent cleaning, removal of stratified rust, loose mill scale, nonadherent paint, weld flux and splatter, and thick edge paint feathering has been verified. Prepared steel must conform to SSPC-SP11 (Steel Structures Painting Council) visual standards SSPC-VIS3, or equivalent.

A.2.3.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect mitigated and monitored by the Protective Coatings Program.

A.2.3.5 Enhancements

The Protective Coatings Program will be expanded to include the external surfaces of carbon steel commodities in-scope for License Renewal that are exposed to inside, outside, submerged, and buried environments as made accessible. Portions of multiple systems will be included, based upon plant-specific operating experience and conditions.

Affected systems will include, but may not be limited to, the nuclear boiler, standby liquid control, residual heat removal, residual heat removal service water, core spray, high pressure coolant injection and reactor core isolation cooling. Certain portions of the-post accident radioactive decay holdup, plant service water, instrument air, drywell chilled water, drywell pneumatics, standby gas treatment, nitrogen inerting, fire protection, diesel fuel oil, piping supports, raceway supports, and building structural steel will also be included. The affected components in these systems will be piping, valves, pumps, bolts, tanks, and structural steel components.

The Protective Coatings Program will be revised to require periodic inspections of in-scope components to ensure that they are properly coated and free of significant age-related degradation. Coated surfaces of certain components, including those normally inaccessible but made accessible due to maintenance or other activities, will also be inspected when they become accessible.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

A.2.4 EQUIPMENT AND PIPING INSULATION MONITORING PROGRAM

A.2.4.1 Description

The Equipment and Piping Insulation Monitoring Program at Plant Hatch is a condition monitoring program designed to detect insulation damage, as well as provide for inspection of specific component insulation located in outside environments.

Plant maintenance program procedures contain limitations to climbing on pipe insulation unless specifically justified by an engineering review and evaluation. Procedures also provide specific instructions for removal, storage and installation of thermal and reflective insulation.

A.2.4.2 Sample Size and Frequency

Outside insulation within the scope of license renewal is currently inspected annually.

A.2.4.3 Industry Codes, Standards and Acceptance Criteria

Plant procedures specify the acceptance criteria for the equipment and piping insulation, including insulation jackets.

A.2.4.4 Aging Effects Requiring an Aging Management Program

Cracking, loss of material, and change in material properties are the aging effects monitored by the Equipment and Piping Insulation Monitoring Program.

A.2.4.5 Enhancements

The Equipment and Piping Insulation Monitoring Program will be expanded to include in-scope portions of inside equipment and piping insulation. Insulation will be periodically examined for holes, tears, compaction, and material separation, wetting, missing insulation and general deterioration, using appropriate visual inspection techniques. Aluminum and galvanized steel insulation jackets and their binders will be visually inspected for cracking and loss of material.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common system components, and midnight June 13, 2018 for Unit 2.

A.2.5 STRUCTURAL MONITORING PROGRAM

A.2.5.1 Description

The Plant Hatch Structural Monitoring Program (SMP) provides condition monitoring and appraisal of certain important structures and structural components. The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program.

The covered structures within the scope of license renewal include the reactor buildings, turbine buildings, intake structure, main stack, diesel generator building, and control building. The condensate storage tank foundations and walls, plant service water valve pits, and nitrogen storage tank foundations are also examined. When practical, digital photography is used to document degradation found.

Structural inspections are primarily visual. Inspected structures include those normally accessible, as well as those below ground or embedded. When normally inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed.

A.2.5.2 Sample Size and Frequency

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. Structures monitored under the provisions of 10 CFR 50.65 (a)(2) are inspected every five operating cycles, unless the conditions, environment, or noted degradation warrant increased frequency. The intake structure is currently inspected every outage because of the humid environmental conditions.

A.2.5.3 Industry Codes, Standards and Acceptance Criteria

The framework for the SMP is consistent with industry guideline NEI 96-03. The NEI 96-03 guidance was conditionally accepted in Regulatory Guide 1.160.

The SMP and supporting programs specify acceptance criteria for structural inspection and evaluation. The acceptance criteria are based upon ACI 349.3R-1996, but also include additional criteria for roof ponding, water leakage, coatings and penetration seals. The SMP acceptance criteria are consistent with NEI-96-03 and NRC Regulatory Guide 1.160, revision 2.

A.2.5.4 Aging Effects Requiring an Aging Management Program

Loss of material, cracking, flow blockage, and material property changes are the aging effects monitored by the Structural Monitoring Program.

A.2.5.5 Enhancements

The scope of the SMP will be expanded to include visual inspections of the following structures and components:

- Sealants in the joints between the reactor building exterior precast siding panels.

- Seismic Category I and Seismic Category II/I piping supports and tube tray supports.
- Seismic Category I HVAC duct supports.
- Seismic Category I and Seismic Category II/I cable trays and cable tray supports.
- Seismic Category I and Seismic Category II/I conduits and conduit supports.
- Seismic Category I Control room panels, racks and supports.
- Seismic Category I Auxiliary panels, racks and supports.
- Reactor building tornado vents.

The frequency of enhanced visual inspections will be based on specific plant experience, commensurate with prudent concern for adequately managing aging. Additional emphasis will be placed on the importance of inspecting and documenting the condition of normally inaccessible (underground or embedded) structures.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1 and common structural components, and by midnight June 13, 2018 for Unit 2.

A.3 NEW PROGRAMS AND ACTIVITIES

New programs or activities were primarily driven by a lack of documented evidence to show that the credited mitigation or prevention activities would be effective into the renewal term. Therefore, for the most part, the new programs and activities are intended to provide objective evidence of the effectiveness of the programs and activities credited for aging management during the renewal term.

New programs or activities will be purposefully delayed until near the end of the current license period (i.e., the last 5 years of the original design life). This will allow assessment of the effectiveness of mitigating or preventive aging management activities and documentation of the original design life condition of the systems being inspected.

A.3.1 GALVANIC SUSCEPTIBILITY INSPECTIONS

A.3.1.1 Description

The Plant Hatch Galvanic Susceptibility Inspections will provide for condition monitoring via one time inspections that will provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal.

Since galvanic corrosion is most likely in commodities within environments that are more corrosive (high impurity and conductivity levels), these inspections will start with the more corrosive raw water environment. Galvanic Susceptibility Inspections will examine a sample population of carbon to stainless steel weld connections that should exhibit the largest galvanic coupling. If the examined carbon to stainless welds show galvanic corrosion, the sample set will be expanded to other water systems.

Piping inspections will be performed using one or more methods. These may include ultrasonic thickness determinations, radiographic testing, depth gauges, and pipe removal and analysis.

A.3.1.2 Sample Size and Frequency

The sample set will be selected from raw water carbon to stainless weld connections following issuance of the new operating license. Examination results will be evaluated to determine whether the sample set should be expanded to other environments. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.1.3 Industry Codes, Standards and Acceptance Criteria

Inspection procedures and acceptance criteria will be developed using the applicable sections of the ASME Code and applicable industry practices.

Where applicable, minimum wall thickness will be calculated in accordance with the piping design code, piping stress requirements, and the piping specification drawings. The acceptance criteria will be contained in the inspection procedures.

A.3.1.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect that will be monitored by the Galvanic Susceptibility Inspections.

A.3.2 TREATED WATER SYSTEMS PIPING INSPECTIONS

A.3.2.1 Description

The plant Treated Water Systems Piping Inspections will provide for condition monitoring via one time examinations intended to provide objective evidence that existing Chemistry Control is managing aging in piping that is not examined under another inspection program.

Treated Water System Piping Inspections will examine a sample population of carbon and stainless steel tubing and piping in the treated water systems. The results of the sample population examinations will be recorded and evaluated, and subsequent examinations will be conducted where evaluation results warrant. If significant degradation is noted, the sample set may be expanded.

Inspections will be conducted using techniques appropriate for piping examination and trending. This may include, but not be limited to, volumetric or destructive examination. The specific sample population, examination methods and acceptance criteria will be defined in the inspection and trending procedures.

A.3.2.2 Sample Size and Frequency

For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018. Subsequent examinations may be conducted on a frequency determined by an engineering evaluation of inspection results.

A.3.2.3 Industry Codes, Standards and Acceptance Criteria

A one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Mechanical joints may be inspected using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Where possible and practical, accessible components may be inspected using volumetric examination methods. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.2.4 Aging Effects Requiring an Aging Management Program

Cracking and loss of material are the aging effects that will be monitored by the Treated Water Systems Piping Inspections.

A.3.3 GAS SYSTEMS COMPONENT INSPECTIONS

A.3.3.1 Description

Plant Hatch Gas Systems Component Inspections will provide for condition monitoring via one time condition monitoring aging management activities designed to provide objective evidence that the aging effects predicted for systems with gases as internal environments are being adequately managed.

Gas Systems Component Inspections will span several systems within the scope of license renewal. Humid and wetted gas internal environments at various temperatures will be inspected.

Procedures will be developed to examine the internal surfaces of a sample population of low points and other susceptible locations in the applicable system components. The Gas Systems Component Inspection activities will use examination techniques designed to ascertain whether significant loss of material or cracking has occurred in the sample population.

A.3.3.2 Sample Size and Frequency

The sample population will include areas of gas bearing piping and ductwork that have the potential for liquid pooling, wet/dry cycling, or thermal degradation. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.3.3 Industry Codes, Standards and Acceptance Criteria

A one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Mechanical joints may be inspected using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Where possible and practical, accessible components may be inspected using volumetric examination methods. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.3.4 Aging Effects Requiring an Aging Management Program

Loss of material, material property changes, and cracking are the aging effects that will be monitored by the Gas Systems Component Inspections.

A.3.4 CONDENSATE STORAGE TANK INSPECTION

A.3.4.1 Description

The plant Condensate Storage Tank (CST) Inspections will provide for condition monitoring via one time inspections intended to provide objective evidence that the aging effects predicted for the CST internal environments are adequately managed by programs credited for the renewal term.

Internal surfaces of each CST will be examined to verify that age-related degradation is not occurring. The examination will focus on the standpipes and the connections between aluminum standpipes and galvanized steel flanges, since these locations would be the most susceptible to corrosion.

A.3.4.2 Sample Size and Frequency

There will be a one-time inspection of each CST. Southern Nuclear anticipates the inspections will be completed coincident with other scheduled CST maintenance. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

A.3.4.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection of each CST will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Specific inspection criteria will be identified in the inspection procedure(s).

A.3.4.4 Aging Effects Requiring an Aging Management Program

Loss of material is the aging effect that will be monitored by the CST Inspections.

A.3.5 PASSIVE COMPONENT INSPECTION ACTIVITIES

A.3.5.1 Description

The passive component inspection activities will be a new condition monitoring aging management activity at Plant Hatch. These inspections will be designed to collect, report and trend age-related data. This activity will verify the effectiveness of preventive or mitigative programs/activities credited for aging management.

In addition to piping, this activity will include the internal and external surfaces of other passive components such as valve bodies, ducting, and strainers. These will be components that are within the scope of license renewal, but which are exempt from ASME Section XI and Generic Letter 88-01 inspections, or other regulatory requirements.

Plant procedures or directives will be developed to require that the selected inscope components be examined. These documents will contain specific inspection criteria and will require recording inspection results.

Plant procedures will include requirements to ensure that inspection results are reviewed, evaluated, and trended. Subsequent inspection frequencies will be determined by the trends in age-related degradation discovered during the inspections.

A.3.5.2 Sample Size and Frequency

Once this activity has been implemented, Southern Nuclear anticipates that baseline inspections will begin for the selected components as those components are made accessible due to normal maintenance activities. The baseline inspections may be done at any time. The activity will be fully implemented no later than midnight August 6, 2014 and midnight June 13, 2018 for Units 1 and 2, respectively.

A.3.5.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection of each component will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Liquid penetrant (PT) examination, or other suitable method dictated by the situation for the affected component, may be used to detect discontinuities open to the component surface. Specific inspection techniques and acceptance criteria will be contained in the inspection procedure(s).

A.3.5.4 Aging Effects Requiring an Aging Management Program

Loss of material and cracking are the aging effects that will be monitored by the passive component inspection activities.

A.3.6 RHR HEAT EXCHANGER AUGMENTED INSPECTION AND TESTING PROGRAM

A.3.6.1 Description

The Plant Hatch Residual Heat Removal (RHR) Heat Exchanger Augmented Inspection and Testing Program is a condition monitoring program that will provide enhanced aging management of both the shell and tube sides of the Unit 1 and Unit 2 RHR heat exchangers. The RHR heat exchangers will be visually inspected, and eddy current testing will be done on a regular basis.

A.3.6.2 Sample Size and Frequency

The RHR Heat Exchanger Augmented Inspection and Testing Program will be fully implemented no later than midnight August 6, 2014 and midnight June 13, 2018 for Units 1 and 2, respectively.

Thereafter, RHR heat exchanger partition plates will be visually inspected once every 54 months. Eddy current testing will be performed on the tubes at least once during each 10-year inspection interval, and whenever leaks are suspected in tubes and/or the tube sheet. The shell side of the tube sheets, shell internals and impingement plates will be visually inspected once per 10-year inspection interval, where accessible. Tube and tube sheet leak testing will be performed whenever leaks are suspected.

A.3.6.3 Industry Codes, Standards and Acceptance Criteria

Visual inspections will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method, as dictated by the situation. Specific inspection techniques and acceptance criteria will be contained in the inspection and testing procedure(s).

A.3.6.4 Aging Effects Requiring an Aging Management Program

Loss of material, loss of heat exchanger performance, and cracking are the aging effects that will be monitored by the RHR Heat Exchanger Augmented Inspection and Testing Program.

A.3.7 TORUS SUBMERGED COMPONENTS INSPECTION PROGRAM

A.3.7.1 Description

The Torus Submerged Components Inspection Program is a condition monitoring activity that will provide a means for evaluating the effectiveness of the current suppression pool chemistry control in preventing loss of material and cracking in the components within the scope of license renewal.

Torus submerged components inspections will be conducted on accessible components submerged in suppression pool water, including the emergency core cooling system (ECCS) pump suction strainers and the reactor core isolation cooling (RCIC) pump suction strainer. The submerged portion of the safety relief valve (SRV) and vacuum relief piping is also included, as is the low carbon steel, Non-Class 1 piping.

Detailed visual inspections for evidence of microbiologically influenced corrosion (MIC), pitting or crevice corrosion, or similar mechanisms will be performed on the in-scope components. Plant procedures or directives will be developed to require that in-scope components be examined. These documents will contain specific inspection criteria and will require recording inspection results. A requirement will be included to ensure that information will be reviewed, evaluated and trended.

A.3.7.2 Sample Size and Frequency

The Torus Submerged Components Inspection Program will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Baseline inspections will be integrated into the routine torus entries. Subsequent inspection frequencies will be determined by engineering evaluation of trends in age-related degradation.

A.3.7.3 Industry Codes, Standards and Acceptance Criteria

Visual inspection will be conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method as dictated by the component configuration. Specific inspection techniques and acceptance criteria will be contained in the inspection procedure(s).

A.3.7.4 Aging Effects Requiring an Aging Management Program

Loss of material and cracking are the aging effects that will be monitored by the Torus Submerged Components Inspection Program.

A.4 TIME LIMITED AGING ANALYSES CREDITED FOR LICENSE RENEWAL

A.4.1 TIME LIMITED AGING ANALYSES

The Rule requires that time limited aging analyses (TLAA) be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40 year operating life of the plant. In addition, the Rule requires that any exemptions based on TLAAs be identified and analyzed to justify extension of those exemptions through the renewal term. Plant Hatch did not have any exemptions based on TLAAs.

TLAA evaluations for Plant Hatch included those calculations and analyses that met all six criteria of the Rule, specifically, those calculations or analyses that:

- involved systems, structures and components (SSC) within the scope of license renewal;
- considered the effects of aging;
- involved time-limited assumptions defined by the licensed operating term at the time of the license renewal application;
- were determined to be relevant in making a safety determination;
- involved conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated by the Rule; and
- were contained or incorporated by reference in the licensing basis at the time of application for renewal.

Given those six criteria, many calculations and analyses qualified as TLAAs. Those TLAAs were comprehensively evaluated, and dispositioned in section 4 of the license renewal application. A summary listing of those calculations and analysis is shown in Table A.4-1.

Once a TLAA has been identified, the Rule requires it be dispositioned by one of the following three specific criteria:

1. the analyses remain valid for the license renewal term; or
2. the analyses have been acceptably projected to the end of the renewal term; or
3. programs are in place to manage the effect of aging in the analyzed systems, structures or components.

With the exceptions of two areas further discussed below, all of the items in Table A.4-1 were entirely dispositioned by Criterion 1 and/or 2 above. As such, these TLAAs were entirely dispositioned through an update of the existing calculations. The two areas dispositioned in part by Criterion 3 are further discussed below.

A.4.1.1 Stress Analysis Calculations

The stress analysis calculations for the RPV, Class 1 piping, and the torus will be monitored to assure that the cumulative usage factor stays less than or equal to 1.0. The details of this program are further described in sections 4.2 and 5.2 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

A.4.1.2 Equipment Qualification Report Evaluations

Aging of electrical equipment falling within the scope of 10 CFR 50.49, that has less than a 60-year qualified life, will be managed by the Plant Hatch Environmental Qualification (EQ) Program. The EQ Program is described in section 7.16 and section 3.11 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

Table A.4-1 Summary Listing of Calculations and Analyses Meeting the Six Time Limited Aging Analyses Criteria

1.	Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant.
2.	Fatigue/stress analyses for the torus structure and nozzle connections.
3.	Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant.
4.	Calculation of the corrosion allowance assumed for the reactor vessel.
5.	Environmental equipment qualification calculations that qualify electrical components for 40 years.
6.	A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant.
7.	Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR 50 Appendix G).
8.	Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR 50 Appendix G) due to the extended operating term.
9.	Analyses performed to demonstrate the acceptability of a technical alternative to the ASME code requirement inspection of reactor pressure vessel circumferential welds.
10.	Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the Plant Hatch FSAR.

A.5 GENERAL REFERENCES

1. TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines."
2. TR-112214, Electric Power Research Institute (EPRI), "BWR Vessel and Internals Project, Proceedings: BWRVIP Symposium, November 12-13, 1998."
3. TR-108705, Electric Power Research Institute (EPRI), "BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection."
4. TR-107396, "EPRI Closed Cooling Water Chemistry Guidelines."
5. Edwin I. Hatch Nuclear Plan, Units 1 and 2 Final Hazards Analysis and Fire Protection Program.
6. Southern Nuclear Operating Company, Plant Hatch, Unit 1 & 2, Third 10-Year Interval Inservice Inspection Program.
7. BAW-2270, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," December 1997.
8. Safety Evaluation enclosed with letter from the Nuclear Regulatory Commission to Southern Nuclear, "Issuance of Amendments – Edwin I. Hatch Nuclear Plant Units 1 and 2," October 22, 1998.
9. "Development of Class 1 Piping Fatigue Formulas and Fatigue Usage Estimates for the Hatch Nuclear Power Plant, Units 1 and 2," Report No. SIR-99-078, August 1999.
10. Hatch Units 1 and 2 Torus Fatigue Analysis Report, REA HT-98674 Response, performed by Southern Company Services on April 16, 1999.
11. Electric Power Research Institute, "Recommendations for an Effective Flow-Accelerated Corrosion Program," EPRI NSAC/202-L.
12. Southern Company Services, "Flow-Accelerated Corrosion (FAC) Program, Hatch Nuclear Plant Units 1 and 2," Volumes 1 and 2.
13. NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment," July 18, 1989.
14. HL-882, "Georgia Power Company Response to Generic Letter 89-13," January 23, 1990.
15. Edwin I. Hatch Nuclear Plant Units 1 and 2, Generic Letter 89-13, "Initial Actions Summary Report," May 1992.
16. NUREG-1275, Volume 3, "Operating Experience Feedback Report - Service Water System Failure and Degradations."
17. A-44985, "Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant," Units 1 and 2, Revision 4.
18. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."
19. Contract Report SAND 93-7070, Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers, June 1994.

20. (BWRVIP-01), "BWR Core Shroud Inspection and Flaw Evaluation Guideline, Revision 2, October 1996."
21. (BWRVIP-07), "Guidelines for Reinspection of BWR Core Shrouds February 1996."
22. (BWRVIP-63), "BWR Vessel and Internals Project Shroud Vertical Weld Inspection and Evaluation Guidelines June 1999."
23. (BWRVIP-38), "BWR Shroud Support Inspection and Flaw Evaluation Guidelines September 1997."
24. (BWRVIP-18), "BWR Core Spray Internals and Flaw Evaluation Guidelines July 1996."
25. (BWRVIP-26), "BWR Top Guide Inspection and Flaw Evaluation Guidelines December 1996."
26. (BWRVIP-41), "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines October 1997."
27. (BWRVIP-47), "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines December 1997."
28. (BWRVIP-03), "BWR Reactor Pressure Vessel and Internals Examination Guidelines."
29. ASME Code, Section XI.
30. (BWRVIP-48), "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines EPRI TR-108724, February 1998."
31. ANSI N5.122-1972, Protective Coatings (Paints) for the Nuclear Industry.
32. ANSI N101.2-1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities.
33. ASTM, Section 6, Volume 06-02, Paints, Products and Applications; Protective Coatings; Pipeline Coatings.

Appendix B

AGING MANAGEMENT PROGRAMS AND ACTIVITIES

For information about Aging Management Programs and Activities, see Appendix A.

Appendix C

IDENTIFICATION OF AGING EFFECTS AND AGING MANAGEMENT REVIEW SUMMARIES

CONTENTS

C.1 EVALUATION OF AGING EFFECTS REQUIRING MANAGEMENT

Introduction

Section C.1 describes the Plant Hatch approach toward identifying, categorizing and evaluating plant environments, materials and the resulting aging effects applicable to systems, structures, and components at Plant Hatch determined to require aging management reviews. Aging effects determined to be not applicable for a given environment are not discussed.

Plant Hatch has adopted a commodities approach to evaluating aging effects requiring management and aging management programs. Section 3.0 of the LRA provides a discussion of the process utilized to develop commodity groups. Once systems, structures, and components were divided into commodity groups, an analysis of the aging effects requiring management was performed.

Mechanical and electrical discipline evaluations in Appendix C are performed based on the operating environment. Materials of construction, aging effects requiring management, and associated aging mechanisms are appropriately discussed under each environment heading. This section is designed as a reference to be used when reviewing the aging management review summaries located in section 2 of Appendix C. As such, redundancy is incorporated into this section of the document since aging mechanisms may be similar for several different environments.

Civil discipline evaluations are based on material of construction. Environments, aging effects requiring management, and associated aging mechanisms are appropriately discussed under each material of construction heading.

The following definitions are used in this application:

An **aging effect** may be defined as a change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms. Examples include loss of material, cracking, loss of fracture toughness, loss of preload, loss of heat exchanger performance, loss of adhesion, and change in material properties.

An **aging mechanism** is any aging process that may result in one or more aging effects.

Change in Insulation Resistance – A change in an insulator's physical or chemical properties such that the required resistance to current or heat flow is no longer provided. A change in insulation resistance may occur due to thermoxidative degradation, water treeing, and radiolysis.

Change in Material Properties – Any change in a material which is detrimental to that material's ability to meet it's design requirements. Mechanisms that may result in a change in material properties include galvanic corrosion, photolysis, radiolysis, thermal degradation, and thermoxidative degradation.

Cracking – Service induced cracking of materials includes both flaw initiation and growth within concrete, concrete masonry, base metals and associated weld materials, and nonmetallics. Aging mechanisms that may result in crack initiation and growth include fatigue, intergranular attack, photolysis and radiolysis of organics, stress corrosion cracking, thermoxidative degradation, and thermal degradation.

Flow Blockage – A reduction in pipeline cross-sectional area such that a significant reduction in flow occurs when the system is called upon to perform its intended function. Flow blockage may be caused by corrosion product buildup, biofouling, particulate fouling, and precipitation fouling.

Loss of Adhesion – A loss of the bond between a structural sealant and the surface to which it is mated. The intrusion of moisture between the sealant and it's mating surface causes a loss of adhesion.

Loss of Conductivity – A loss of the ability of a conductor to carry rated current. Aging mechanisms which cause loss of electrical conductivity include galvanic corrosion and atmospheric corrosion of metals used in terminations and connections.

Loss of Fracture Toughness – A change in the material properties of a metal such that design requirements are potentially compromised. Aging mechanisms that contribute to loss of fracture toughness include irradiation embrittlement and thermal embrittlement.

Loss of Heat Exchanger Performance – A loss of heat exchanger performance due to a buildup of materials on the system surfaces. Loss of heat exchanger performance may occur by any of the mechanisms determined to cause flow blockage.

Loss of Material – A reduction in the material content of a component or structure and may occur evenly over the entire component surface or be confined to localized areas. Aging mechanisms which may result in loss of material include: corrosion of embedded steel in concrete, crevice corrosion, erosion corrosion, galvanic corrosion, general corrosion, selective leaching, microbiologically influenced corrosion, pitting, thermal degradation, thermoxidative degradation, and wear.

Loss of Preload – A general reduction in the tensile load for a bolted connection. Aging mechanisms contributing to loss of preload in bolted connections include embedment, gasket creep, thermal effects, and self-loosening.

C.1.1 PLANT HATCH SERVICE ENVIRONMENTS

The service environment in which components operate, along with other factors, establishes the aging effects of concern for license renewal. This section identifies the service environments for the areas that contain structures and components subject to an aging management review. The service environments identified in this section are thermal, radiation, and moisture.

Thermal Environments

Thermal data were obtained from HVAC design calculations supplemented by actual temperature measurements, and combined into tables. Table C.1.1-1 presents a summary of the thermal environmental conditions by location, so that the structures and components installed in each location can be analyzed for aging resulting from location-specific, worst-case design environments.

Radiation Environments

Design radiation maximums specific to normal operation were obtained from EQ program data. These values are considered conservative maximums. The actual 40-year dose will be lower, and in some cases, much lower. For areas of the plant not listed in the EQ program data, the 40-year dose (gamma) is negligible. Table C.1.1-1 presents a summary of the radiation environments.

The expected normal dose for 60 years at Plant Hatch can be determined by multiplying the 40-year normal dose by 1.5 (i.e., 60 yr/40 yr).

Moisture

Exterior surfaces of structures and components located in yard areas are subject to moisture from weather conditions such as dew, rain, fog, snow, or sleet. Plant Hatch is located in a rural area and is not near major industrial plants or seawater, so the plant is not exposed to sulfate or chloride attack.

Components such as the Intake Structure and associated piping are exposed to the waters of the Altamaha River. Water quality in the Altamaha River is good. Concentrations of minerals and nutrients are low, with dissolved solids typically less than 150 mg/l.

The quality of the groundwater in the vicinity of Plant Hatch is good. The groundwater pH ranges between 7.4 and 7.9. The chloride concentration ranges between 3.0 and 10.0 ppm, and the sulfate concentration ranges between 0 and 20.0 ppm.

Components located inside structures may have short-term exposure to standing water from spills or normal system leakage. Localized corrosion that occurs as a result of a short-term event is corrected through normal plant maintenance activities. These conditions are considered to be event-driven and are not considered in license renewal aging management reviews.

Table C.1.1-1 Plant Hatch Thermal and Radiation Environments

Structure or Area	Specific Area Description and Comments	Max. Temp. (°F)	60-yr. Radiation Dose (Rads)
Reactor Building Unit 1	Primary Containment	Location Specific	9.17×10^7
Reactor Building Unit 1	Pipe Penetration Room	120	3.0×10^6
Reactor Building Unit 1	Pipe Chase	120	1.02×10^7
Reactor Building Unit 1	HPCI Pump Room	100	8.84×10^3
Reactor Building Unit 1	RHR Corner Room (SE)	100	8.84×10^3
Reactor Building Unit 1	RHR Corner Room (NE)	100	8.84×10^3
Reactor Building Unit 1	RCIC Corner Room (SW)	100	8.84×10^3
Reactor Building Unit 1	CRD Pump Room (NW)	<100	*
Reactor Building Unit 1	Torus Room	120	5.84×10^4
Reactor Building Unit 1	RWCU HX Room	110	9.0×10^6
Reactor Building Unit 1	El. 130'	100	5.84×10^2
Reactor Building Unit 1	El. 158'	100	5.84×10^2
Reactor Building Unit 1	El. 164'	100	5.84×10^2
Reactor Building Unit 1	El. 185'	100	5.84×10^2
Reactor Building Unit 1	El. 203'	100	5.84×10^2
Turbine Building Unit 1	East Cableway	<100	Not Applicable
Reactor Building Unit 2	Primary Containment	Location Specific	9.17×10^7
Reactor Building Unit 2	Pipe Penetration Room	105	3.0×10^6
Reactor Building Unit 2	Pipe Chase	105	1.09×10^7
Reactor Building Unit 2	HPCI Pump Room	105	8.84×10^3
Reactor Building Unit 2	RHR Corner Room (SE)	104	8.84×10^3
Reactor Building Unit 2	RHR Corner Room (NE)	104	8.84×10^3
Reactor Building Unit 2	RCIC Corner Room (NW)	105	8.84×10^3
Reactor Building Unit 2	CRD Pump Room (SW)	105	8.84×10^3
Reactor Building Unit 2	Torus Room	105	5.84×10^4
Reactor Building Unit 2	RWCU HX Room	90	9.0×10^6
Reactor Building Unit 2	El. 130'	90	5.84×10^2
Reactor Building Unit 2	El. 158'	90	5.84×10^2
Reactor Building Unit 2	El. 164'	90	5.84×10^2
Reactor Building Unit 2	El. 203'	90	5.84×10^2
Turbine Building Unit 2	East Cableway	<100	Not Applicable

* No calculated dose for this area. Expected to be similar to Unit 2 CRD Room

Table C.1.1-1 Plant Hatch Thermal and Radiation Environments (Continued)

Structure or Area	Specific Area Description and Comments	Max. Temp. (°F)	60-yr. Radiation Dose (Rads)
Control Building	Working Floor	<100	Not Applicable
Control Building	Cable Spreading Room	<100	Not Applicable
Control Building	Switchgear Rooms	<105	Not Applicable
Diesel Generator Building		<100	Not Applicable
Intake Structure		<120	Not Applicable

C.1.2 MECHANICAL DISCIPLINE AGING EFFECTS

For each applicable environment identified by mechanical discipline screening, aging effects requiring management and a discussion of the associated aging mechanisms are provided below.

C.1.2.1 Reactor Grade Water

Reactor grade water is used in the power cycle. The water is demineralized and maintained with low levels of detrimental impurities (such as halogens and sulfates) and minimal dissolved oxygen concentrations. This water is supplied to the reactor pressure vessel (RPV) via the condensate and feedwater systems. Reactor water exits the reactor pressure vessel as saturated steam and in some cases two phase flow may exist. Any vapor or two phase environment is considered to be part of the reactor water environment and all aging effects within inscope steam system environments determined to require management are evaluated within the reactor water section. Reactor grade water quality is maintained in accordance with the Reactor Water Chemistry Control Program. This program implements the guidance of EPRI BWR water chemistry guidelines.

The materials of construction exposed to this environment include wrought and forged stainless steel, cast austenitic stainless steel, nickel base alloys, and carbon steel. The aging effects requiring management and associated aging mechanisms applicable to these materials in the reactor water environment are discussed below.

C.1.2.1.1 Loss of Material Within the Reactor Grade Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the BWR is a potentially significant aging mechanism for carbon steel within the primary water environment. As will be discussed with flow accelerated corrosion (FAC), low dissolved oxygen contents, (e.g., <30 ppb), achieved to prevent stress corrosion cracking of stainless steels and nickel-base alloys can cause accelerated corrosion of carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic or lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic or higher corrosion potential) decreases. This phenomenon is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. In the reactor water environment carbon steel components electrically coupled to stainless steel or nickel base alloys are susceptible to galvanic corrosion.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant (dissolved oxygen in the BWR coolant) can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, some of which (sulfate and chloride) can accelerate both corrosion and stress corrosion cracking (SCC) initiation and growth. Crevice corrosion is potentially significant for all BWR structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all BWR structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion (MIC) is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the reactor water environment, MIC is most likely in stagnant areas having lower operating temperatures.

Wear and fretting are defined as the removal of surface material due to relative motion between surfaces or under the influence of hard, abrasive particles. Mechanical wear occurs in components that experience considerable motion in clamped joints where relative motion is not intended, but occurs due to a loss of clamping force. It may also occur in components that experience relative motion after being held together under high loads with no motion for a long period of time (such as when a flanged joint or valve bonnet is removed for maintenance). Wear and fretting, as an aging mechanism is potentially significant only for large bore Class 1 components where high loads and extreme temperature cycles are involved.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within the reactor water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value.

Recently, FAC has been used to specifically describe the thinning of carbon steel alloys in nuclear (and fossil) power plants where there is no threshold solution velocity. FAC is a complex phenomenon that is a function of many parameters of water chemistry (pH, oxygen and temperature), material composition, (Cr, Cu and Mo content) and hydrodynamics (steam quality, velocity and geometry) and involves the electrochemical aspects of general corrosion plus the effects of mass transfer and momentum transfer. The correct interpretation of any FAC data depends on evaluation of all of these variables. An indication of how these variables impact carbon steel FAC are listed below:

Variable	FAC increases if Variable is
Pipeline Velocity	Higher
pH	Lower
Oxygen	Lower
Steam Quality	0.1 – 0.9
Temperature	250 – 400 °F
Geometry	Conducive to higher turbulence
Chromium content	Lower
Copper content	Lower
Molybdenum content	Lower

FAC can be quantitatively evaluated by utilizing EPRI recommendations for an effective flow accelerated corrosion program. Since stainless steels and low alloy steels have sufficient alloying elements to mitigate FAC, FAC is not an aging phenomenon for these groups of alloys.

Cavitation erosion refers to conditions within a component where, owing to a local pressure drop, cavities filled with vapor are formed; these cavities collapse as soon as the vapor bubbles reach regions of higher pressure. Removal of protective corrosion films and base metal occurs as a result of high localized stresses produced in the metal surface due to collapse of vapor bubbles.

Impingement is characterized by inertial damage of protective corrosion films exposing small anodic regions and has been observed on numerous components exposed to high velocity low quality steam.

C.1.2.1.2 Cracking Within the Reactor Grade Water Environment

Stress corrosion cracking is the term given to this sub-critical crack growth of susceptible alloys under the influence of a tensile stress of sufficient magnitude and a "corrosive" environment. Many alloys when subjected to an external or residual tensile stress and in contact with certain specific environments develop cracks. SCC is a very complex phenomenon that has interrelated mechanical, electrochemical and metallurgical factors.

SCC can proceed through a material in two modes, intergranular (through the grain boundaries) and transgranular (through the grains). Sometimes the modes are mixed or the mode switches from one mode to the other. Intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC) often occur in the same alloy depending on the environment, the microstructure or the stress/strain state. IGSCC is the predominate form of SCC in the BWR.

For the BWR, the initiation of IGSCC of structural materials in the reactor water environment occurs when the following necessary conditions are simultaneously present:

Susceptible material – The IGSCC of stainless steel and nickel base alloys predominately requires a chromium depleted zone at the grain boundary in weld heat affected zones (HAZs) due to chromium carbide ($Cr_{23}C_6$) precipitation, i.e., "sensitization." However, sensitization is not necessary if the material is creviced or cold worked. IGSCC susceptible structural materials include essentially all austenitic stainless steels, (e.g., Types 304, 316, 304L, 316L, etc.), nickel-base alloys, (e.g., Alloy 600, X-750, etc.), and nickel-base weld metals, (e.g., Alloy 182, 82, etc.). Austenitic stainless steel weld metal is highly resistant to IGSCC.

Tensile stress - The threshold tensile stress for IGSCC typically exceeds the material's at-temperature yield stress. Sources of tensile stress include applied, residual, thermal, welding and even corrosion product. As-welded material typically contains weld residual tensile stresses approaching the yield stress of the material. The threshold tensile stress for IGSCC is reduced by 50% if the material is creviced.

Corrosive environment – High temperature water where the electrochemical corrosion potential (ECP) of alloys within the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide is necessary for IGSCC initiation. Although the presence of detrimental impurities such as sulfate and chloride are not required for IGSCC in the BWR, their presence at levels as low as 5 ppb will accelerate both IGSCC initiation and crack propagation.

A reduction in the susceptibility of alloys to IGSCC in the BWR has been accomplished through the use of sensitization resistant materials such as Type 316NG stainless steel (Hatch Unit 2 recirculation piping), solution heat treatment, corrosion resistant cladding and weld overlays. Tensile stress reduction techniques include heat sink welding, induction heating stress improvement, and mechanical stress improvement.

Irradiation assisted stress corrosion cracking (IASCC) is also a form of IGSCC. However, there are some major differences between the two phenomena that warrant their different designations. First, stainless steel that suffers IASCC is not thermally "sensitized." Second, the IASCC phenomenon is material irradiation exposure time dependent, i.e., unlike sensitized stainless steel where the material is susceptible to IGSCC from day one, annealed stainless steel only becomes susceptible upon exceeding a certain threshold fluence value as a function of stress level.

As modeled on IGSCC, the initiation of IASCC in austenitic stainless steel reactor internals appears to occur when the following necessary conditions are simultaneously present:

Susceptible material – Radiation induced segregation of impurities, (e.g., P, Si, S), nickel enrichment and mild chromium depletion at the grain boundary in annealed material, i.e., classical thermal sensitization not required, as a result of a fluence exceeding ~3-5 x 10^{20} n/cm^2 E>1.0 MeV. The primary physical effect of irradiating a metal with fast neutrons is the displacement of atoms, the subsequent production of vacant lattice sites (vacancies) and interstitials and enhanced diffusion.

Tensile stress – Unlike the IGSCC for uncreviced BWR piping, the threshold stress level for IASCC is below the yield stress, time dependent and is a function of fluence. Also, irradiation can lead to stress relaxation via a creep mechanism or to a stress increase through the formation of hydrogen atoms by radiolysis and transmutation. Also, because of the highly oxidizing nature of the environment, corrosion oxide films tend to be much thicker than for IGSCC. Since the oxide on stainless steel has a greater specific volume than the parent corroded metal, IASCC crack growth can also be driven by the resultant oxide wedging stresses that result from thick oxide at the crack tip.

Corrosive environment – High temperature water where the electrochemical corrosion potential (ECP) of the stainless steel in the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide. Although the presence of detrimental impurities such as sulfate and chloride are not necessary for IASCC in the BWR, their presence will accelerate both IASCC initiation and crack propagation.

At Plant Hatch, only a small set of near core internals exceed the neutron fluence threshold required to render a component susceptible to IASCC.

Intergranular attack (IGA) is the precursor of IGSCC in the reactor water environment. Since grain boundary atoms even in "pure" metals are more loosely packed than the matrix material, grain boundaries preferentially corrode. This is normal for general corrosion where the grain boundary corrodes at only a slightly higher rate than the grain. However, alloys such as stainless steels and nickel-base alloys are more readily attacked due to impurity segregation, (e.g., P, Si, S, etc.), enrichment or depletion of alloy elements, (e.g., sensitization), and/or heat treatment induced solid state reactions. When the grain boundaries are affected by one or more of these three factors, the degree of localized attack is significantly more severe. Once the depth of IGA exceeds 2 mils, it electrochemically acts as a crack. The presence of a tensile stress greater than the threshold stress will subsequently result in IGSCC propagation. Aside from initiating IGSCC, IGA serves as nucleation sites for pitting and environmentally assisted fatigue.

Thermal fatigue is a structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. The reactor recirculation pump covers and integral heat exchangers have been proven especially susceptible to cracking due to thermal fatigue cycles. Carbon steels, alloy steels, austenitic stainless steels, and nickel base alloys are all susceptible to damage due to fatigue resulting from thermal cycling. The presence of an oxidizing environment, as the Hatch primary coolant pressure boundary piping system was exposed to prior to implementation of hydrogen water chemistry, can accelerate the fatigue crack initiation and propagation process. This is commonly referred to as environmentally assisted fatigue or corrosion fatigue. Based on the decision criteria and conservative formulae utilized in creating cumulative usage factor equations for Class 1 components, environmental effects of reactor water have been adequately incorporated into the Plant Hatch Component Cyclic or Transient Limit Program. Therefore, the thermal fatigue aging mechanism identified throughout ASME Class 1 sections of this application is also considered to encompass any relevant environmental effects of reactor water.

C.1.2.1.3 Loss of Fracture Toughness Within the Reactor Grade Water Environment

Thermal embrittlement of cast austenitic stainless steels may occur based on prolonged exposure to operating temperatures in excess of 480 °F. The resulting aging effect is a reduction in the fracture toughness of a material as a function of time. The magnitude of the reduction depends on casting method, material chemistry, and the duration of exposure to operating temperatures conducive to the embrittlement process. Based on the EPRI screening guidelines for evaluation of thermal embrittlement for cast austenitic stainless steels, a limited subset of castings at Plant Hatch have been determined to be potentially susceptible to thermal embrittlement. These castings include reactor recirculation pump casings and covers, and certain large bore valve bodies within the reactor recirculation system.

Irradiation embrittlement (neutron embrittlement) is the result of atomic displacements within a material due to atomic collisions. These displacements produce defects that change the property of the metal and result in a loss of fracture toughness. Irradiation embrittlement is a function of two variables:

- Copper and nickel content within the alloy.
- Neutron fluence exceeding a minimum threshold value.

Only RPV alloy steel beltline shells and associated welds and certain austenitic stainless steel RPV internals exposed to neutron fluences exceeding the minimum threshold value are potentially susceptible to loss of fracture toughness due to irradiation embrittlement.

C.1.2.2 Auxiliary Systems (Demineralized, Suppression Pool, Spent Fuel Pool, and Borated Waters)

Auxiliary system environments are those with the potential to cross tie to the reactor pressure vessel. The water in these systems is demineralized (pure) with no corrosion inhibiting chemical or biocide additions and no control of dissolved oxygen concentrations. While acceptable levels for impurities may vary among systems, these differences are driven by the relative potential for any given system to supply water to the reactor pressure vessel and not focused on excluding aging effects. The aging effects requiring management and definitions of associated aging mechanisms are similar for all auxiliary systems. Chemistry parameters for these systems implement the recommendations of EPRI BWR water chemistry guidelines. At Plant Hatch, four “auxiliary systems environmnets” are included within this evaluation:

Demineralized Water is processed by an on site demineralizing system and is stored in the demineralized water storage tanks and condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels but dissolved oxygen concentrations are not controlled or monitored.

Suppression Pool Water (Torus Water) is contained within the torus and consists of demineralized water supplied from demineralized water sources (such as the condensate storage tanks). Detrimental impurities and conductivity are maintained at low levels, though allowable levels are well above those acceptable for demineralized water. Dissolved oxygen concentrations are not controlled or monitored.

Spent Fuel Pool Water is contained within the spent fuel pool and consists of demineralized water supplied from demineralized water sources (such as the demineralized water storage tank). Detrimental impurities and conductivity are maintained at low levels similar to the levels maintained within the suppression pool water environment. Dissolved oxygen concentrations are not controlled or monitored.

Borated Water is contained within the standby liquid control system and consists of demineralized water supplied from the demineralized water storage tank, with approximately 10% by weight sodium pentaborate added. Sodium pentaborate solutions have pH values in the neutral range. While conductivity within this solution is high, the concentrations of aggressive anion species are quite low, thereby minimizing significant corrosion within the system. The standby liquid control storage tank is not regularly monitored for detrimental impurities.

The materials of construction exposed to these pure water environments include stainless steel, carbon steel, galvanized steel (used in the CST only), and aluminum alloys (used in the CST and spent fuel pool only). The aging effects requiring management and associated aging mechanisms applicable to these materials in these auxiliary system water environments are discussed below.

C.1.2.2.1 Loss of Material Within Auxiliary System Water Environments

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in auxiliary systems is a potentially significant aging mechanism only for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within auxiliary systems, carbon steel and aluminum alloys may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth.

Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In auxiliary system environments, MIC is most likely in stagnant areas having lower operating temperatures.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within auxiliary systems. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant within auxiliary systems in areas of high turbulence or pressure fluctuations.

Cavitation erosion refers to conditions within a component where, owing to a local pressure drop, cavities filled with vapor are formed; these cavities collapse as soon as the vapor bubbles reach regions of higher pressure. Removal of protective corrosion films and base metal occurs as a result of high localized stresses produced in the metal surface due to collapse of vapor bubbles. Cavitation erosion may be possible within auxiliary systems in areas of substantial localized pressure changes such as downstream of reduction orifices or throttle valves.

C.1.2.2.2 Cracking Within Auxiliary Systems Water Environments

Stress corrosion cracking occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. For a particular material, high stresses require less corrosive environments, and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC can be categorized as either IGSCC or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. Within the auxiliary systems environments a low temperature threshold temperature of 140 °F was assumed for stress corrosion cracking of stainless steel. Based on this threshold, only certain stainless steel components in the HPCI and RCIC turbine discharge headers inside the torus, where operating temperatures occasionally exceed 200 °F, are postulated to be susceptible to SCC.

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though auxiliary system water temperatures are generally less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.3 Closed Cooling Water

Closed Cooling Water is monitored for detrimental impurities, though the parameters are less restrictive than for reactor water or auxiliary system water environments. Corrosion inhibitors designed to form passivating films on anodic surfaces are utilized. A basic pH is maintained to increase the effectiveness of the corrosion inhibitors and promote the development of protective corrosion films. Biocide levels are maintained to prevent significant microorganism growth. Guidelines for acceptable chemistry parameters for closed cooling water systems are in accordance with EPRI closed cooling water chemistry guidelines.

The materials of construction exposed to these closed cooling water environments include stainless steel, carbon steel, and brass. The aging effects requiring management and associated aging mechanisms applicable to these materials in closed cooling water environment are discussed below.

C.1.2.3.1 Loss of Material Within the Closed Cooling Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the closed cooling water environment is a potentially significant aging mechanism only for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within the closed cooling water environment, carbon steels may be susceptible to galvanic corrosion when coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments except for brass components having high zinc content that prevents significant crevice corrosion from occurring.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion (i.e., deaerated, stagnant, low pH and high impurity concentration). While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments except for brass components having high zinc content that prevents significant pitting from occurring.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the closed cooling water environment, MIC is most likely in stagnant areas of the systems.

Selective leaching (also known as dealloying corrosion) of brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the closed cooling water environment.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel components within the closed cooling water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant within the closed cooling water environment in areas of high turbulence or pressure fluctuations.

C.1.2.3.2 Cracking Within the Closed Cooling Water Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though closed cooling water temperatures are less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAAs and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See <u>section 4.2.3</u> of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.4 Raw Water (River Water and Well Water)

Two types of raw water are defined:

River water is supplied from the Altamaha River via the intake structure. Water supplied from the Altamaha River is rough screened at the intake structure. This screening is designed to prevent clogging of vertical turbine pumps and discharge strainers. It is assumed that some debris, silt, and macroorganisms may be introduced into the plant service water and residual heat removal service water systems. The materials of construction exposed to the river water environment include: stainless steels, carbon steel, cast iron, brass, and copper.

Well water is supplied from deep draft wells located on site. Well water is mechanically filtered using the demineralizing system filters prior to use to remove macroorganisms and silt and is utilized by fire protection systems only. Many different material types are exposed to the well water environment.

C.1.2.4.1 Loss of Material within the Raw Water Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the raw water environment is a potentially significant aging mechanism for carbon steels and cast irons.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within the river water and well water environments, carbon steels and cast irons, and copper alloys, to a lesser degree, may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to stagnant environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to stagnant environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the raw water environment, MIC is most likely in stagnant areas with heavy corrosion product buildup.

Selective leaching (also know as dealloying corrosion) of cast iron and brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the raw water environment.

Erosion corrosion, as defined by SNC, encompasses all flow related aging mechanisms including erosion corrosion, FAC, cavitation erosion, and impingement and is potentially significant for carbon steel and cast iron components within the river water environment. The general term erosion corrosion includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear or abrasion plus corrosion. .Erosion corrosion normally occurs when the solution velocity exceeds a threshold value and is potentially significant for carbon steel and cast iron within the raw water environment in areas of high turbulence or pressure fluctuations.

Fouling may be due to particulate, precipitation, or biological organisms. As with MIC, fouling is not a material degradation phenomenon but may increase corrosion rates within raw water system components for a limited set of component geometries. In these areas, particulate, precipitates, or biological organisms adhere to the component surface and create shielded areas and crevices that promote localized corrosion mechanisms. Fouling mechanisms are described in greater detail in section C.1.2.4.3.

Wear is an applicable aging mechanism requiring management for tube to tubesheet and tube to baffle connections within the RHR heat exchangers. Vibration within the heat exchanger can cause collisions of tubes and baffles to occur, thereby resulting in loss of material within the heat exchangers.

C.1.2.4.2 Cracking within the Raw Water Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though raw water temperatures are less than 120 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

Vibration fatigue is an applicable aging mechanism for the RHR heat exchangers. Cyclic loads are experienced at all times during heat exchanger operations and industry experience indicates damage due to vibration within these heat exchangers has occurred. The tubes and tubesheets are most susceptible to vibration fatigue.

C.1.2.4.3 Flow Blockage Within the Raw Water Environment

Fouling may result in a significant buildup of material on raw water system component internal surfaces. This buildup will most likely occur in areas having creviced geometries and lower pipeline velocities. Eventually the reduction of flow area will result in an inability of the system to meet its intended function since sufficient flow and adequate pressure may not be delivered. As described above, fouling may also create areas conducive to localized corrosion mechanisms. The following four types of fouling are considered significant within raw water systems at Plant Hatch:

- **Corrosion product buildup** may be expected to occur in all river water and well water components since no chemistry controls are employed to limit general corrosion rates in carbon steels and cast irons. Corrosion products may be transported throughout the system and deposited on materials not generally considered susceptible to general corrosion. Heavy corrosion product buildup on component surfaces produces shielded areas along the material surface where crevice corrosion, pitting, and MIC may be promoted. Heavy corrosion product buildup on component surfaces can also lead to a reduction of flow area.

- **Biofouling** may occur via microbiological organisms or macroorganisms. Any biological organisms introduced into raw water systems may deposit on component surfaces and create biofilms that are conducive to localized corrosion mechanisms and provide ideal locations for further buildup of material on component surfaces. Fouling due to macroorganisms is only significant in river water systems (service water). Fire protection systems are supplied by onsite wells with filtering employed to eliminate the possibility of macroorganisms entering the system.

- **Particulate fouling** consists of both river silt and other larger debris fine enough to pass through the intake pit screens and enter the service water systems. Particulate fouling is not considered plausible for fire protection systems since filters would eliminate intrusion of particulates into the system.

- **Precipitation fouling** may occur when mineral compounds are precipitated out of solution and adhere to component surfaces. Precipitation fouling is most prevalent within heat exchanger surfaces.

C.1.2.4.4 Loss of Heat Exchanger Performance Within the Raw Water Environment

Loss of heat exchanger performance is restricted to the RHR system heat exchangers. See section C.2.2.11.1.

Fouling - All of the fouling types described in section C.1.2.4.3 are applicable to RHR heat exchangers. Any buildup of material on heat exchange surfaces will result in some loss of heat exchanger performance.

C.1.2.5 Fuel Oil

Fuel oil is any oil utilized to fuel an internal combustion engine. The materials of construction for this internal environment include stainless steel, carbon steel, brass, bronze, copper, and gray cast iron. The aging effects requiring management and associated aging mechanisms applicable to these materials in the fuel oil environment are discussed below.

C.1.2.5.1 Loss of Material Within the Fuel Oil Environment

Fuel oils in their pure form are nonaggressive and noncorrosive to metals. However, intrusion of water contamination will create an aggressive environment within fuel oil system components and additives to fuel oils may increase the potential for corrosion if water intrusion occurs. Loss of material due to corrosion may only occur if water contamination is present. If the assumption is made that water intrusion from rain or ground water is possible, a conservative estimate of the potential aging mechanisms is obtained. The reader is referred to the raw water section (C.1.2.4) of this document for a description of how these aging mechanisms apply and proceed in various materials. No discussion of specific aging mechanisms leading to loss of material is provided in this section.

C.1.2.5.2 Cracking Within the Fuel Oil Environment

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See section 4.2.3 of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.5.3 Flow Blockage

Flow blockage due to buildup of sediment has been determined to be applicable for copper tubing supply lines to the fire protection pump diesel engine.

C.1.2.6 Gases

The gas environment is defined as any line containing noncondensable gases and includes both dried and nondried gases.

Dried gases describe any process gas including, but not limited to, air, nitrogen (including cryogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or is filtered and desiccated to remove moisture prior to entering the system. Sufficient moisture to drive aging mechanisms is not present. The only aging effect requiring management for dried gases is cracking due to thermal fatigue. This is a conservative assumption and thermal fatigue is managed by TLAA. See section 4.2.3 of the LRA.

Nondried gases include air (nitrogen in the case of the inerted drywell) containing humidity or significant moisture. Nondried gas environments are found inside buildings, inside the drywell, and outside. These gases are assumed to contain sufficient entrained moisture and oxygen to enable pooling of liquid at low or especially cool locations and promote corrosion. Containment atmosphere processed by inscope systems is considered within this category of internal environment.

The materials of construction exposed to a gas environment include carbon steel, stainless steel, galvanized steel, and copper alloys.

C.1.2.6.1 Loss of Material Within the Gas Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. General corrosion in the nondried gas environment is a potentially significant aging mechanism for carbon steels.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Within a nondried gas environment, carbon steels may be susceptible to galvanic corrosion when electrically coupled with stainless steel components.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to pooling or wet/dry nondried gas environments.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to pooling or wet/dry nondried gas environments.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the nondried gas environment, MIC is only potentially significant in areas where long term pooling of liquid occurs.

Selective leaching (also known as dealloying corrosion) of cast iron and brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the nondried gas environment wherever significant pooling may occur on brass or cast iron surfaces.

C.1.2.6.2 Cracking Within the Nondried Gas Environment

Stress corrosion cracking occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. For a particular material, high stresses require less corrosive environments, and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC can be categorized as either IGSCC or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. Within the nondried gas environment certain stainless steel components are located in areas where pooling of moisture and wet/dry cycling are possible. In addition, the location of these components (upper elevations of the drywell or near main steam lines) are such that ambient temperatures approach 200 °F at times. Plant Hatch has assumed a 140 °F threshold temperature for initiation of SCC. Based on this environment, SCC is a potentially significant aging mechanism for certain stainless steel components.

Intergranular attack initiates by a mechanism similar to stress corrosion cracking and has been also assumed to have a lower threshold temperature of 140 °F below which IGA will not occur. Therefore, as with SCC, only those stainless steel, nondried gas system components exposed to upper drywell atmosphere or near main steam components are susceptible to IGA.

Thermal fatigue is the structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. Even though gas system temperatures are generally less than 200 °F under normal operating conditions and no significant thermal cycling is expected, Plant Hatch has determined that all non-Class 1 components are enveloped by TLAA and that thermal fatigue is adequately addressed by this analysis without regard to individual component or system conditions. Therefore, no analysis need be performed to exclude specific systems or components. See <u>section 4.2.3</u> of the LRA for a discussion of thermal fatigue TLAAs.

C.1.2.7 Pressure Boundary Bolting

Pressure boundary bolting includes carbon steel, alloy steel, and stainless steel bolting, applicable to license renewal. The following aging effects and mechanisms are applicable to Class 1 and non-Class 1 bolting. Note that cracking due to thermal fatigue is applicable only to reactor pressure vessel closure head studs due to high installation tensile stresses and extreme thermal cycles.

C.1.2.7.1 Loss of Material

Loss of material may occur within fasteners by several different corrosion mechanisms. Fasteners experience environments similar to any other mechanical component external surface—inside, outside, and buried—with an increased potential for wetting than other piping components due to gasket leakage. At Plant Hatch, buried fasteners only exist in a few areas within fire protection systems. Since the environments are similar, although the many shielded areas and crevices associated with threaded connections increase the potential for significant corrosion, loss of material mechanisms for fasteners are included with mechanical external surfaces aging mechanism descriptions.

C.1.2.7.2 Loss of Preload

Embedment - Fastener and joint surfaces are microscopically rough. When first assembled, these surfaces only contact each other on high spots. These high spots tend to creep and flow until a larger surface contact area is obtained. Preload is lost as these parts "settle in" together. Joints subject to large cyclic loads will embed and relax more than joints under static loads. Therefore, embedment is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

Gasket creep - To function properly, gaskets are designed to deform plastically when loaded. Minor loss of preload may be experienced as these gaskets "creep," that is, to gradually flow or compress outward under a compressive load. Therefore, gasket creep is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

Thermal effects - Differential expansion between bolts and joint members due to thermal effects may increase stresses and thereby cause embedment or gasket creep. Creep of bolts and gaskets can be promoted by high temperature through a process called stress relaxation. Since significant thermal cycles are required to produce thermal effects, only those fasteners operating at higher temperatures are susceptible to this aging mechanism.

Self-loosening - Vibration, flexing of the joint, cyclic shear loads, thermal cycles, and other factors can cause whole or partial self-loosening of a fastener. Therefore, self-loosening is a significant aging mechanism for all pressure boundary bolting, regardless of material of construction.

C.1.2.7.3 Cracking

Thermal fatigue is a structural deterioration of a material that can occur whenever expansion or contraction of a body resulting from a change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. The reactor pressure vessel closure head studs are susceptible to cracking due to thermal fatigue cycles. These fasteners represent a high stress area within the Class 1 boundary. Other bolting at Plant Hatch is not installed with sufficient stresses to cause fatigue to be a significant mechanism.

C.1.2.8 Inside

An inside environment indicates that the equipment is sheltered from the weather. The inside environment assumes 50% - 90% humidity, an ambient temperature less than 120 °F (except for primary containment), and a maximum radiation level of 9.0×10^6 rads. The inside environment also includes components located within the primary containment structure. The containment environment assumes 40% - 90% humidity, a bulk average ambient temperature defined by data obtained from RTDs, and a maximum radiation level of 9.17×10^7 rads outside the sacrificial shield wall.

The materials of construction having an inside environment include carbon steel, stainless steel, galvanized steel, and copper alloys.

C.1.2.8.1 Loss of Material Within the Inside Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. However, significant general corrosion is limited to carbon steel components operating at less than 200 °F since any component with an external surface temperature greater than 200 °F would not retain surface moisture for a significant amount of time and subsequently, corrosion rates will be limited.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels and cast irons whenever wetted conditions exist and electrical connections to stainless steel components are simultaneously present.

Selective leaching (also know as dealloying corrosion) of cast iron or brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism within the inside environment anywhere localized wetting is possible.

C.1.2.8.2 Cracking

Thermal fatigue is the structural deterioration of a material that can occur whenever contraction or expansion of a body resulting from a change in temperature is prevented by some constraint. These constraints may either be externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas.

C.1.2.9 Outside

Outside is defined as any external environment found outside any structure that would protect it from the weather. The environment assumes 0% to 100% humidity, an ambient temperature less than 120 °F, and no radiation.

The materials of construction having an outside environment include carbon steel, stainless steel, galvanized steel, cast iron, aluminum alloys, and copper alloys.

C.1.2.9.1 Loss of Material Within the Outside Environment

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. In the outside environment general corrosion is limited to carbon steel and cast iron components and will be most significant in areas where pooling of rainwater or process waters occurs.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels and cast irons whenever wetted conditions exist and electrical connections to stainless steel components are simultaneously present.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all structural alloys exposed to pooling or wet/dry within the outside environment.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all structural alloys exposed to pooling or wet/dry within the outside environment.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the outside environment, MIC is only potentially significant in areas where long term pooling of liquid occurs.

Selective leaching (also known as dealloying corrosion) of cast iron or brass components occurs when the more active (anodic) portion of the matrix is preferentially corroded and the more noble (cathodic) portion of the matrix remains. This is a potentially significant aging mechanism in the outside environment anywhere localized wetting is possible.

C.1.2.9.2 Cracking

Thermal fatigue is the structural deterioration of a material that can occur whenever contraction or expansion of a body resulting from a change in temperature is prevented by some constraint. These constraints may either be externally imposed or self imposed due to the configuration of the body and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas.

C.1.2.10 Buried or Embedded

The buried or embedded environment includes components buried beneath the surface of the ground (in some cases with controlled backfills) or embedded in structural concrete.

The materials of construction having a buried or embedded environment include carbon steel, stainless steel, cast iron, and copper.

C.1.2.10.1 Loss of Material Within the Buried or Embedded Environment

Underground carbon steel piping is covered with a protective coating that is expected to greatly reduce the rates of corrosion occurring on the external surfaces of buried piping. Plant Service Water (PSW), Residual Heat Removal Service Water (RHRSW), and Diesel

Fuel Supply Piping were coated with enamel and wrapped with a fiber wrap saturated in coal tar in accordance with AWWA C203-66 when buried. These coatings are expected to prevent corrosion except in those locations where the coating is breached.

General corrosion is characterized by an electrochemical reaction that proceeds uniformly over an entire surface area. The metal thins down and can eventually fail by either penetration or the lack of cross sectional area to support a load. Wetting due to groundwater is possible for all buried components and therefore general corrosion is a potentially significant aging mechanism for buried carbon steel components.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. This is the basis for sacrificial anodes, galvanizing, cathodic protection systems, etc. Therefore, galvanic corrosion is a potentially significant aging mechanism for carbon steels when groundwater wetting of the components and electrical connections to stainless steel components are simultaneously present.

Crevice corrosion is characterized by a geometrical configuration in which the cathodic reactant can readily gain access by convection and diffusion to the metal surface outside the crevice, whereas access to the layer of stagnant solution within the crevice is far more difficult and can be achieved only by diffusion through the narrow mouth of the crevice. After a brief period of time, the oxygen initially within the crevice becomes depleted and the oxygen reduction corrosion reaction ceases within the crevice. The continued cathodic reduction reaction of oxygen outside of the crevice results in continued anodic dissolution of the metal within the crevice and the buildup of excess unstable cations. The cations in the crevice solution can hydrolyze in water and precipitate as hydroxides creating an excess of hydrogen cations in the crevice solution. The increase in hydrogen ion concentration results in a decrease in pH (i.e., an acid environment). This resultant positive charge imbalance is then necessarily balanced by the migration of negatively charged ions into the crevice, which can accelerate corrosion. Crevice corrosion is potentially significant for all susceptible structural alloys exposed to groundwater within the buried environment.

Pitting can be defined as a limiting case of localized attack in which only small areas of the metal surface are attacked while the remaining area is largely unaffected. The mechanism of pitting is very similar to crevice corrosion, i.e., deaerated, stagnant, low pH and high impurity concentration. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as MnS particles in carbon steels, surface dislocation intersections, defects, etc. determine the site of pitting. Also, the relative probability of identifying a pit of a given depth is a function of area, i.e., the larger the surface area, the greater the probability of finding a pit of a certain depth. Pitting is potentially significant for all susceptible structural alloys exposed to groundwater within the buried environment.

Microbiologically influenced corrosion is not another form of corrosion, per se, but rather it is the influence of viable organisms on well-characterized corrosion mechanisms. In some circumstances, microbial activity does nothing more than establish a localized environment that is conducive to corrosion based solely upon geometric consideration such as the formation of "living crevices." This condition may occur simply as the result of absorption of nutrients such as oxygen creating concentration cells beneath areas of microbial growth. Microbes can also produce metabolites such as organic or mineral acids, ammonia or hydrogen sulfide that are corrosive to several materials. A number of microbes can concentrate halides that result in severe corrosion of iron-based alloys. In still other cases, MIC interferes with the cathodic half reaction under oxygen free conditions resulting in increased anodic dissolution. These bacteria create creviced geometries under tubercles that tend to concentrate aggressive anions in oxygen deficient regions. In the outside environment, MIC is only potentially significant in areas where long term wetting of susceptible surfaces by groundwater occurs.

Selective leaching (also known as dealloying corrosion) of brass components occurs when the more active (anodic) zinc within the matrix is preferentially corroded and the copper portion of the matrix remains. Therefore, selective leaching is a potentially significant aging mechanism within the buried environment.

C.1.2.11 Aging Effects Requiring Management for Insulation Components

C.1.2.11.1 Loss of Material

Intrusion of water and water borne agents applies to insulation located outside and nonembedded fire penetration seal insulating materials. Water may ingress through the protective insulation sheathing and collect in the insulation system. The water may contain agents such as nitrates, sulfates, hydrogen ions, minerals, salts, etc. which can have a deteriorating effect on insulation materials, resulting in loss of material and a subsequent loss of insulation effectiveness.

Wear can occur when there is relative motion or sliding between stationary objects such as pipe supports and walls, and insulation. Insulation material can be rubbed off the pipe, equipment, or penetration seal and reduce its effectiveness. Relative motion can be created by thermal movement, vibration, and dynamic effects such as hydraulic transients. When relative motion occurs, insulating materials may degrade due to wear.

C.1.2.11.2 Cracking

Thermal degradation may be due to elevated temperature degradation or low temperature degradation. Elevated temperature degradation applies to outside insulation used with heat tracing and embedded fire penetration seals. These insulation materials can experience cracking when exposed to high temperatures over a long period of time. Heat aging cracks can reduce insulation effectiveness. Low temperature degradation applies to the diesel CO_2 storage tank insulation only. The refrigeration system for this tank maintains the CO_2 at a constant 0 °F. Insulation materials can experience cracking when exposed to continuously low temperatures over a long period of time. Aging cracks can reduce insulation effectiveness.

Intrusion of water and water borne agents applies to outside insulation and nonembedded fire penetration seal insulating materials. Water may ingress through the protective insulation sheath and collect in the insulation system. Repeated freeze/thaw cycles may cause the insulation material to crack.

C.1.2.11.3 Change in Material Properties

Compaction/settling due to dead weight and/or gravity has been determined to be a significant aging mechanism for insulation. Insulation can experience compaction and/or settling due to its own weight and the weight of protective jackets (outside insulation) or the weight of pipes/conduits (fire penetration seals) over a long period of time. Compaction and/or settling reduces the insulation thickness which can reduce insulation effectiveness.

Compaction/settling due to intrusion of water and water borne agents applies to outside insulation and nonembedded fire penetration seals. Water may ingress through the protective insulation sheath and collect in the insulation system. This may cause the insulation to become soggy resulting in compaction or settling of the insulation material and thus reduce its thickness. Water soaked insulation may also sag and pull away from the piping or equipment being insulated. Reduced thickness or sagging insulation can result in reduced insulation effectiveness.

Thermal degradation may be due to elevated temperature degradation or low temperature degradation. Elevated temperature degradation applies to outside insulation used with heat tracing and embedded fire penetration seals. Insulation material can experience a breakdown in the structural properties which bond adjacent layers of material together when exposed to high temperatures over a long period of time. This heat aging process can result in separation of layers of material for piping and equipment insulation. For fire penetration seals, this heat aging process can result in both separation of layers of material and separation from walls or components. Low temperature degradation applies to the diesel CO_2 storage tank insulation only. The refrigeration system for this tank maintains the CO_2 at a constant 0 °F and the insulation is continuously exposed to this low temperature. Insulation material can experience a breakdown in the structural properties which bond adjacent layers of material together when exposed to low temperatures over a long period of time. This process can result in separation of layers of insulation material. Material separation can reduce insulation effectiveness.

C.1.3 ELECTRICAL AGING EFFECTS

The process to determine aging effects applicable to electrical components begins with an understanding of the aging effects identified in the industry literature. From this set of aging effects, those which require management are determined by examining the component materials, service environments, and operating stresses for each component type. In addition to the review of industry literature, Plant Hatch-specific operating experience was reviewed to provide reasonable assurance that all aging effects were identified for the aging management review.

After defining the various internal and external environments to which a particular component/commodity may be exposed, it is next necessary to discuss the particular aging mechanisms and aging effects that may be present in these environments. Aging effects and aging mechanisms can be defined as follows:

An aging effect may be defined as a change in a system, structure, or component's performance, or change in physical or chemical properties resulting in whole or part from one or more aging mechanisms. Examples for electrical components include change in insulation resistance, change in material properties, cracking, loss of conductivity, and loss of material.

An aging mechanism is any aging process that may result in one or more aging effects. Aging mechanisms for electrical discipline components include: atmospheric oxidation of metals, galvanic corrosion, hydrolytic degradation, photolysis of organic materials, radiolysis of organic materials, thermal degradation of organic materials, thermoxidative degradation, and water treeing.

Electrical component types subject to an aging management review (AMR) are electrical cables, connectors, splices, terminal blocks, Nelson frames, and phase bussing. The identification of the aging effects requiring management for electrical components considered the following list of aging effects, which has been compiled by reviewing available industry literature.

- Loss of Material – Loss of material is a reduction in the material content of a component or structure and may occur evenly over the entire component surface or be confined only to localized areas.
- Cracking – Defects in nonmetallic materials resulting in physical separation, typically beginning at the surface and progressing through the material. Cracking in nonmetallic materials is a primary concern for cable insulation and jacket material.
- Loss of Conductivity – Inability of a component to carry sufficient electrical current.
- Change in Insulation Resistance – A change in an insulator's physical or chemical properties such that the required resistance to current or heat flow is no longer provided.
- Change in Material Properties – Any change in a material which is detrimental to that material's ability to meet its design requirements.

These aging effects can be expected to occur due to the following aging mechanisms depending upon environmental conditions:

- Thermal degradation of organic materials
  - Loss of material
  - Cracking / Embrittlement
  - Change in material properties
  - Change in insulation resistance
- Thermoxidative degradation
  - Loss of material
  - Cracking / Embrittlement
  - Change in material properties
  - Change in insulation resistance
- Radiolysis of organic materials
  - Cracking / Embrittlement
  - Change in insulation resistance
  - Change in material properties
- Water treeing
  - Change in insulation resistance

Three environmental conditions must be evaluated to assess the aging effects associated with nonmetallic materials used in electrical components at Plant Hatch. These are high temperature, radiation, and moisture. A summary of the evaluations of the aging effects associated with these environmental conditions for each electrical component type follows.

High Temperature Aging Effects

High temperatures can result in thermal degradation and thermoxidative degradation of electrical components. The EQ Program has evaluated the effects of high temperatures on electrical components within the scope of the program. Arrhenius methodology is used to analyze thermal test data and calculate qualified lives for the various components in the program. Since electrical cables, connectors, splices, and terminal blocks within the scope of license renewal have already been tested and evaluated for high temperature aging effects by the EQ program, the EQ data and evaluations can be used to determine whether or not aging effects associated with high temperature require management for the components within the scope of license renewal.

Electrical cables, connectors, splices, and terminal blocks within the license renewal scope are located throughout the reactor building, control building, the lower regions of the drywell (primary containment), certain limited areas of the turbine building, and in various other buildings such as the diesel generator building and the intake structure. Allowable temperatures corresponding to a 60-year service life for these component types were compared to the maximum bounding temperatures of the various plant areas. In all cases, the plant temperatures were lower than the allowable 60-year temperatures of the components. From this it is concluded that no aging effects associated with high temperature require management for electrical cables, connectors, terminal blocks, and splices.

The same types of evaluation were performed for Nelson frames and phase bussing. While these component types are not within the scope of the EQ program, the nonmetallic materials associated with these components were evaluated using an industry material database, and 60-year temperatures were determined. These were greater than the applicable plant temperatures in all cases. No aging effects associated with high temperature require management for Nelson frames or phase bussing.

Radiation Aging Effects

A radiation environment can result in radiolysis of organic materials. Aging effects associated with radiation have been evaluated for electrical cables, connectors, splices, and terminal blocks in the EQ Program. Allowable 60-year radiation doses have been determined for these components. Using this data, the allowable 60-year doses for the components within the license renewal scope were determined. These values were compared to the calculated dose associated with each plant area in which the components are located. The allowable dose is greater than the expected dose in all cases. No aging effects associated with radiation require management for cables, connectors, splices, or terminal blocks.

The materials of construction of Nelson frames and the portion of phase bussing in scope have been evaluated for radiation aging effects using industry material data. The allowable dose for these components is greater than the expected dose in all cases. No aging effects associated with radiation require management for Nelson frames and the portion of phase bussing within the license renewal scope.

Aging Effects Related To Moisture

Water penetration into electrical cable insulation can result in reduced dielectric strength due to increased conductivity of the insulation caused by increased ion mobility and concentration. Increased conductivity results in increased leakage current flowing either through or on the surface of the insulation, eventually resulting in permanently degraded dielectric strength. Cables constructed with ethylene propylene rubber insulation have a relatively high resistance to moisture intrusion.

Water treeing is a degradation and long-term failure phenomenon, which has been documented for medium-voltage electrical cable with certain types of polyethylene and ethylene propylene rubber insulation. Water trees occur in hydrophobic polymers used as insulating materials when the materials are exposed to electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth of water trees is unpredictable and erratic. Water treeing is seen most often in cables operated at higher voltages; few occurrences have been documented in cables operated below 15 kV.

C.1.4 CIVIL DISCIPLINE AGING EFFECTS

The process to determine the aging effects applicable to structural components begins with a review of the aging effects identified in industry literature. From this set of aging effects, the Plant Hatch materials, operating environment (internal and external) and operating stresses serve to determine aging effects that need to be managed. Finally, the Plant Hatch-specific operating experience, industry-wide operating experience and CLB are reviewed to identify any additional aging effects that require aging management. This process provides reasonable assurance that the full set of aging effects was established for the aging management review.

To facilitate the identification of aging effects requiring management, the structural components have been grouped as follows:

- Structural Steel and Aluminum Components
- Concrete Components
- Structural Sealants
- Acrylic

Determination of the aging effects requiring management for each of these groups is presented in sections C.1.4.1 through C.1.4.4. The discussions address the applicable aging effects and the associated aging mechanism(s) that may cause the aging effect.

C.1.4.1 Structural Steel and Aluminum Components

The structural steel and aluminum components are grouped into commodities to efficiently perform the aging management reviews described in sections C.2.6.2 through C.2.6.6. The component types that make-up the commodity groups are collectively reviewed. As an aid to the reader, many of the component types included in these reviews are repeated here:

- Primary containment steel component types such as the containment shell plate, headers and downcomers, penetrations, bellows, bracing, supports, restraints, columns and saddles
- Building and structural steel component types such as beams, girders, columns, bracing, hangers, plate, and liner plate
- Miscellaneous structural steel and aluminum component types such as door frames, blow-out panels, tornado vent support frames, plate, sheet metal, penetrations, pipe, tubing, supports, grating, stairs, handrails, and various miscellaneous shapes
- Bolts and anchors such as structural bolts, cast in place bolts, expansion and wedge anchors

The component types are made from carbon steel, low alloy steel, galvanized steel, stainless steel and aluminum. The process for identifying the aging effects that require aging management was applied to the structural steel and aluminum components. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. In addition, sections C.1.2.1 through C.1.2.4 of this appendix further discuss steel in various water environments. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Loss of material due to general corrosion, pitting, crevice corrosion, and MIC.
- Cracking due to fatigue.

Loss of Material

General corrosion is characterized by an electrochemical reaction between a material and its environment. It normally proceeds uniformly, at a slow and predictable rate, over an entire surface area resulting in material dissolution or corrosion product buildup. At ordinary temperatures and neutral or near neutral media, both oxygen and moisture must be present to corrode steel. General corrosion is an applicable aging mechanism for uncoated carbon steels and high-strength low alloy steels. Stainless steel is very resistant to general corrosion. Loss of material by general corrosion is not an applicable aging effect for stainless steel.

Zinc coatings (or galvanizing) protect steel from general corrosion. The corrosion rate of zinc coatings depends on the type of ambient conditions involved. Factors such as the frequency and duration of moisture content, rate of drying, and the extent of industrial pollution have significant impact on the corrosion rate. Galvanized steel that is protected from acids, alkalis and atmosphere/weather is expected to have negligible corrosion rates. While the thickness of galvanizing was not specified for Plant Hatch, it is widely accepted that hot dipped galvanized steel will have a coating thickness of about 2.1 mils. The expected service life of such a coating should be about 50 years in an outside rural environment and over 60 years in an inside environment. However, in the absence of known galvanizing weights or coating thickness, an isolated or localized incidence of a loss of the zinc coating is plausible. Therefore, loss of zinc by general corrosion is an applicable aging effect for galvanized steel.

Pitting is an extremely localized corrosive attack in aqueous environments containing dissolved oxygen and chlorides. It is more common in austenitic (300 series) stainless than in carbon steels and aluminum. When passivity breaks down at a spot on a metal surface, an electrolytic cell is formed with the anode at the minute area of active metal, and the cathode at the considerable area of passive metal. The large electric potential difference between the two areas accounts for considerable flow of current with rapid corrosion at the anode. The anode does not spread because it is surrounded by passive metal, and as the mechanism continues it penetrates deeper into the metal forming a pit. Pitting is an applicable aging mechanism for uncoated structural steel and aluminum exposed to dissolved oxygen and chlorides in aqueous environments. This includes uncoated surfaces that are exposed to stagnant aqueous environments such as water pooling and where wet/dry conditions occur in the outside environment.

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It most frequently occurs in connections, lap joints, splice plates, bolt threads, under bolt heads, crevices adjacent to steel to concrete embedments and is associated with a stagnant solution (an electrolyte). The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. The crevice also retains moisture for a longer time than adjacent external surfaces, allowing a longer duration for corrosion damage to occur. The level of oxygen concentration in the electrolyte when present, is lower in the crevice making it anodic to surrounding areas in this differential oxygen cell and commencing active corrosion. The same cell is formed when the amount of oxygen reaching metal that is covered by rust or other insoluble reaction product is less than the amount that contacts other portions where the permeable coating is thinner or absent. Crevice corrosion is an applicable aging mechanism for structural steel and aluminum components where crevices that are exposed to stagnant solutions may exist.

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. The active (anodic, lower corrosion potential) metal surface suffers accelerated corrosion while the corrosion rate of more noble metal surface (cathodic, higher corrosion potential) decreases. Galvanic corrosion will not occur in a dry environment. An electrolyte must be present and remain liquid. The ratio between surface areas of the metals in contact is of significant importance. Corrosion rates increase when the more noble metal has a greater surface area than the more active metal. Therefore, galvanic corrosion is an applicable aging mechanism for structural steel components exposed to wetted conditions and composed of two or more metals of differing electrochemical potential. Aluminum alloys are anodic to both carbon and stainless steels and would be preferentially corroded. Therefore galvanic attack is an applicable aging mechanism for aluminum alloy components at dissimilar metal welds.

Microbiologically influenced corrosion occurs by the action of microorganisms. Microorganisms are usually classified according to their ability to grow in the presence or absence of oxygen. Aerobic organisms grow in nutrient mediums containing dissolved oxygen. Anaerobic organisms grow most favorably in environments containing little or no oxygen. Selected aerobic organisms produce sulfuric acid by oxidizing sulfur or sulfur-bearing compounds. Selected anaerobic organisms reduce sulfate to sulfide ions, which influences both anodic and cathodic reactions on iron surfaces. These microscopic organisms have been observed to live in media with pH values between 0 and 11, temperatures between 30 °F and 180 °F, and under pressure up to 15,000 psi. MIC is facilitated by stagnant conditions, fouling internal crevices, and contact with untreated water from a natural source. Microorganisms such as iron bacteria are important in their effect on steel as they live by digesting iron and manganese ions into their cells. Iron bacteria flourish in running and stagnant water environments with temperatures of 40 °F to 100 °F and pH environments between 4 and 10. MIC is an applicable aging mechanism for structural steel and aluminum components that are submerged in water or saturated environments (e.g., soils) for long periods of time.

Cracking

Fatigue failure, in structural steel and steel components, is initiated by a plastic deformation in a localized region. A nonuniform stress distribution across a member cross-section may cause concentrated stresses to exceed the yield point within a small area of the cross-section resulting in a small plastic movement and a minute crack. The reduced cross-sectional area aggravates the stress distribution, which causes the crack to progress. After a relatively small number of stress cycles, a final, sudden fracture of the remaining cross-section occurs.

Generally, structural steel and steel components are not prone to fatigue. Loads, for the most part, are applied gradually and remain constant. Dynamic loads such as wind and seismic loads are too infrequent to initiate fatigue cracking. Members subjected to fatigue loading conditions such as crane runways are accounted for by code in their design. In addition, crane use is limited and the number of stress cycles experienced is low in terms of fatigue service life when considering the period of extended operation.

Thermal fatigue is a structural deterioration of material that can occur whenever expansion or contraction of a body resulting from change in temperature is prevented by some constraint. These constraints may be either externally imposed or self imposed due to the configuration of the component and the temperature distribution. If sufficient microstructural damage has been accumulated, crack initiation and growth may occur at the most highly affected areas. A review of the Plant Hatch CLB determined that fatigue is an applicable aging mechanism for certain primary containment, pressure boundary structural steel components.

C.1.4.2 Concrete Structural Components

The concrete structural components are grouped into a commodity to efficiently perform the aging management reviews described in section C.2.6.1. The component types that make-up the commodity group are collectively reviewed. As an aid to reader, many of the component types included in the review are repeated here:

- Masonry block walls
- Equipment foundations
- Floors, sumps and roofs
- Columns, slabs and beams
- Interior and exterior walls (above and below grade)

The component types are composed of concrete, reinforcing steel and grout. The process for identifying the aging effects that require aging management was applied to concrete structural components. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Loss of material due to corrosion of embedded steel.
- Cracking in masonry block walls due to expansion or contraction.

Loss of Material Assessment

Corrosion of embedded steel is an electrochemical process that results in the formation of ferric oxide (rust). The corrosion products have a significantly greater volume than the original metal resulting in tensile stresses and spalling in the surrounding concrete. There are typically two types of embedded steel for concrete: reinforcing steel which is completely covered by concrete and steel which has a surface interface with the concrete such as embed plates or other structural steel members.

The high alkalinity (pH > 12.5) of concrete provides an environment around embedded steel which protects it from corrosion. If the pH is lowered (e.g., to 10 or less), corrosion may occur. However, the corrosion rate is still insignificant until a pH of 4.0 is reached. A reduction in pH can be caused by the leaching of alkaline products through cracks, the entry of acidic materials, or carbonation. Chlorides can be present in constituent materials of the original concrete mix (i.e., cement, aggregates, admixtures, and water), or they may be introduced environmentally. The severity of corrosion is influenced by the properties and type of cement and aggregates as well as the concrete moisture content.

The primary place that corrosion could occur is on the surface of Category I structures where moisture and oxygen may have access to the embedded steel. As discussed in C.1.4.1, embedded steel at the surface of the concrete is susceptible to crevice corrosion cracking. Corrosion products have a volume greater than the original metal. The presence of corrosion products subjects concrete to tensile stress, eventually causing hairline cracking, followed by rust staining and spalling. Exterior concrete components that are exposed to an aggressive environment on an ongoing basis are susceptible to embedded steel corrosion. Therefore, corrosion of embedded steel at the surface of the concrete is an applicable aging mechanism.

The degree to which concrete will provide satisfactory protection for steel reinforcement depends in most instances on the quality of the concrete and the depth of concrete cover over the steel. The permeability of the concrete is also a major factor affecting corrosion resistance. Concrete of low permeability contains less water under a given exposure and is more likely to have lower electrical conductivity and better resistance to corrosion. Such concrete also resists absorption of salts and their penetration into the embedded steel and provides a barrier to oxygen, an essential element of the corrosion process. Low water-to-cement ratios and adequate air entrainment increase resistance to water penetration and thereby provide greater resistance to corrosion.

The concrete structures and structural members at Plant Hatch are designed and constructed in accordance with ACI and ASTM standards that provide a good quality, dense, low permeability concrete that provides adequate concrete cover over the embedded reinforcing steel. As such, corrosion of embedded reinforcing steel is not an applicable aging mechanism for concrete structures and structural members exposed to interior environments and atmosphere/weather. However, if the concrete is degraded by other mechanisms, which reduce the protective cover of the steel reinforcement, corrosion may occur. Aggressive chemical attack is not a concern for the concrete components that are exposed to concentrations of chlorides that are less than 500 ppm, for concentrations of sulfates that are less than 1500 PPM, and for a pH of 5.5 or greater. At Plant Hatch, the ground water and river water chemistry are well within these limits.

Cracking

Expansion or contraction may result in cracking of masonry block walls whenever any restraint is imposed that will prevent the wall from free expansion or contraction. Restraint against expansion generally results in small stresses as compared with the strength of the block wall materials and thus rarely causes degradation of the masonry block wall. Restraints against free contraction are much more likely to cause significant tensile stresses. If these tensile stresses exceed the tensile strength of the unit, the bond strength between the mortar and the unit, or the shearing strength of the horizontal mortar joint, cracks will occur to relieve the stresses.

Expansion or contraction of masonry block walls may be caused by changes in temperature, changes in moisture content of the constituent materials, contraction due to carbonation, and/or movement of adjacent structural components. Therefore, cracking of masonry block walls is an applicable aging effect for block walls within the reactor building, control building, and main stack.

C.1.4.3 Structural Sealants

The structural sealants are grouped into a commodity to efficiently perform the aging management reviews described in section C.2.6.7. The sealant types that make-up the commodity group are collectively reviewed. As an aid to the reader, the sealant types included in the review are repeated here:

- Joint and caulk sealant in the joints between the exterior precast panels for the reactor buildings
- Main control room environmental control system duct gaskets and flex connectors.

The component types are composed of nonmetallic inorganic elastomers, elastomers, and nonasbestos synthetic fibers.

The process for identifying the aging effects was applied to structural sealants. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Material property changes and cracking due to thermal exposure
- Loss of adhesion due to exposure to excessive moisture

Material Property Changes and Cracking

Material property changes may occur in sealants and sealant materials that are continually exposed to temperatures above 95° F. A drying or curing effect causes the more volatile chemicals in the sealant to evaporate. As the material composition changes, the material becomes stiffer and exhibits a temporary increase in strength, but will eventually result in less elastic behavior and an overall loss of strength. Exposed surfaces of the sealants become harder and exhibit brittleness and loss of elasticity. When the materials are subjected to tension or compression forces, in the event of expansion or contraction, cracking may occur. Therefore, thermal exposure is an applicable aging mechanism for the structural sealants.

Loss of Adhesion

Exposure to excessive moisture may cause the sealant to pull away or separate from the surfaces to which it is mated. The quality of the bond is dependent on the ability of the adhesive to adhere to the surface to which it is bonded. Degradation of the bond is caused when a moisture agent, such as water, permeates the surface discontinuities that naturally occur in most materials, and begins to destroy the bond between the sealant and the mating surface. The sealant will begin to exhibit peeling and loss of bonding to the mating surface. Exposure to excessive moisture is an applicable aging mechanism for the structural sealants.

C.1.4.4 Acrylic

The tornado vent assembly domes are made of acrylic, and are evaluated in section C.2.6.8. The acrylic is Plexiglas G cellcast acrylic polymer. The chemical name is polymethyl methacrylate composed of carbon, hydrogen, and oxygen. No fillers are added as part of the forming process and material contains no significant halogens or sulfur. The process for identifying the aging effects was applied to the acrylic. As discussed above, the process considers the materials, operating environments and operating stresses. The Plant Hatch service environments are discussed in section C.1.1 of this appendix. Applying the process resulted in the following list of aging effects and associated aging mechanisms:

- Cracking

Cracking Assessment

Cracking of the acrylic dome on the tornado roof vent assemblies is due to weathering, since the domes are exposed to the outside.

C.1.5 INDUSTRY OPERATING EXPERIENCE REVIEW

The systematic evaluation of environments and materials to identify those aging effects requiring management in the renewal term for the renewal term is presented in appendix C, section C.1. This evaluation was performed using information developed based on available industry knowledge. A review of pertinent generic industry operating experience, as contained in NRC generic communications, was a part of the process for determining aging effects requiring management. The generic communications listed in table C.1.5-1 were evaluated as part of the process, the results of which are contained in this section for the various materials and environments combinations at Plant Hatch.

Table C.1.5-1 Generic Communications Reviewed as Part of the Systematic Evaluation to Determine Aging Effects Requiring Management

Circular	80-007	Problems with HPCI Turbine Oil System
Circular	80-011	Emergency Diesel Generator Lube Oil Cooler Failures
Generic Letter	83-026	Clarification of Surveillance Requirements for Diesel Fuel Impurity Level Tests
Generic Letter	84-011	Inspections of BWR Stainless Steel Piping
Generic Letter	87-005	Potential Degradation of Mark I Drywells
Generic Letter	88-001 S1	NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping
Generic Letter	89-008	Erosion/Corrosion-Induced Pipe Wall Thinning
Generic Letter	89-013	Service Water System Problems Affecting Safety-Related Equipment
Generic Letter	91-013	Essential Service Water System Failures at Multi-Unit Sites
Generic Letter	91-017	Bolting Degradation or Failure in Nuclear Power Plants
IE Bulletin	81-003	Flow Blockage of Cooling Water to Safety System Components by Corbicula SP
Information Notice	79-023	Emergency Diesel Generator Lube Oil Coolers
Information Notice	80-005	Chloride Contamination of Safety-Related Piping and Components
Information Notice	81-021	Potential Loss of Direct Access to Ultimate Heat Sink
Information Notice	81-038	Potentially Significant Equipment Failures Resulting From Contamination of Air-Operated Systems
Information Notice	85-008	Industry Experience On Certain Materials Used In Safety-Related Equipment
Information Notice	85-030	Microbiologically Induced Corrosion of Containment Service Water System
Information Notice	85-034	Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping
Information Notice	85-056	Inadequate Environment Control for Components and Systems in Extended Storage or Lay-up
Information Notice	86-096	Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems
Information Notice	86-099	Degradation of Steel Containments
Information Notice	88-037	Flow Blockage of Cooling Water to Safety System Components
Information Notice	88-082, S1	Torus Shells With Corrosion and Degraded Coatings in BWR Containments

Table C.1.5-1 Generic Communications Reviewed as Part of the Systematic Evaluation to Determine Aging Effects Requiring Management (Continued)

Information Notice	89-007	Failures of Small Diameter Tubing in Control Air, Fuel, Oil, and Lube Oil Systems Render Emergency Diesels Inoperable
Information Notice	89-030	Excessive Drywell Temperatures
Information Notice	90-026	Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety-Feature Systems
Information Notice	91-046	Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems
Information Notice	92-020	Inadequate Local Leak Rate Testing
Information Notice	92-081	Potential Deficiency of Electrical Cables with Bonded Hypalon Jackets
Information Notice	93-033	Potential Deficiency of Certain Class 1E Instrumentation and Control Cables
Information Notice	98-002	Nuclear Power Plant Cold Weather Problems and Protective Measures

C.2 AGING MANAGEMENT REVIEWS

Section C.2 of Appendix C provides an aging management summary for each unique structure, component, or commodity group at Plant Hatch determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management, aging management programs utilized to manage these aging effects, and a demonstration as to how the identified aging management programs manage aging effects requiring management using attribute tables. Section C.1 of the LRA provides discussion of aging effects and environments. Appendix A of the LRA provides descriptions of aging management programs required to manage aging effects requiring management.

C.2.1 AGING MANAGEMENT REVIEWS FOR CLASS 1 MECHANICAL DISCIPLINE COMMODITIES

C.2.1.1 Class 1 Components Environment Description

Class 1 components are subject to an environment of reactor water under normal conditions. The reactor water environment is defined in section C.1.2.1.

C.2.1.1.1 Aging Management Review for the Reactor Pressure Vessel

The reactor pressure vessel (RPV) consists of the following components:

- Shell and closure heads
- Nozzles, Appurtenances, and Penetrations
- Attachments and connecting welds (brackets and lugs)
- RPV head closure studs

The RPV and associated components are constructed from carbon steel, low alloy steel, austenitic stainless steel, and nickel based alloys.

Systems

B11 – Reactor Assembly (2.3.1.1)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC) and fatigue.
- *Loss of fracture toughness* (C.1.2.1.3) due to neutron embrittlement.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Reactor Pressure Vessel (RPV) Monitoring Program* (A.1.17)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking

Reactor Water Chemistry Control serves to manage cracking due to SCC by controlling electrochemical corrosion potential (ECP) in accordance with the recommendations of EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *RPV Monitoring Program* is based upon the implementation of ASME Section XI, NUREG-0619, Generic Letter 88-01 as described in the ISI Program, as well as Boiling Water Reactor Vessel Internals Program (BWRVIP) requirements. The RPV Monitoring Program provides for volumetric, visual, and surface examinations of the RPV to provide adequate assurance that no significant crack initiation and growth has occurred. Additionally, it provides validation that the Reactor Water Chemistry Control Program is adequate to mitigate crack initiation and growth due to stress corrosion cracking within the RPV.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor (CUF) for several bounding locations within Class 1 components to verify that adequate margin against crack initiation and growth due to fatigue is maintained.

The *RPV Monitoring Program* provides for volumetric, visual, and surface examinations of the RPV to provide adequate assurance that no significant crack initiation and growth due to fatigue has occurred.

Management of Loss of Fracture Toughness due to Irradiation Embrittlement

Irradiation embrittlement is only applicable to beltline shell material and beltline weldments where the neutron fluence is greater than 1×10^{17} n/cm^2 for neutrons with energies greater than 1 MeV. Management of this aging effect is accomplished by the *RPV Monitoring Program* which provides guidelines for operation and inspection of the RPV in accordance with Appendices G and H of 10 CFR 50 and the BWRVIP. However, existing analyses at the time of application indicate that operation to 60 years is acceptable. See sections 4.6.1 and 4.6.2 of the LRA.

Review of Operating Experience

A review of the operating experience for both Hatch units indicates that there are no outstanding problems. Routine examinations as part of the ISI program and augmented in-vessel inspections, as well as normal maintenance and refueling activities have not revealed any age related issues for the reactor vessel. There was one instrument penetration that developed a leak attributed to IGSCC. The leak was detected as part of normal drywell outage activities and repaired. Corrosion was detected on the mating surface of the Unit 2 RPV head vent flange and repaired. Finally, during a routine maintenance activity, CRD flange bolts were found to have evidence of pitting. All CRD flange bolts were replaced and are inspected routinely upon disassembly.

Applicability of BWRVIP and Commitments to NRC Safety Evaluation Reports

The BWR Vessel and Internals Program (BWRVIP) developed inspection and evaluation reports for internals components and submitted them to NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed the internals relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of the internals for renewal by concluding the rule provisions have been satisfied including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstrating that these programs will assure the functionality of internals into the renewal term. The initial SERs impose the following requirements on a licensee adopting these reports for the renewal term:

- 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 BWRVIP report to manage the effects of aging on the functionality of the reactor vessel during the period of extended operation. 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 BWRVIP 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 10 CFR 54.21(a)(3) and (c)(1).
- 10 CFR 54.21(d) requires that a FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP report for a component shall ensure that the programs and activities specified as necessary in the BWRVIP document are summarily described in the FSAR supplement.
- 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In the BWRVIP report, the BWRVIP stated that there are no generic changes or additions to technical specifications associated with the component(s) as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP reports shall ensure that the inspection strategy described in the BWRVIP

document does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.

This section evaluates the Hatch RPV attachments, nozzles, and penetrations against the above criteria and establishes the acceptability of those components for the license renewal term. In addition, TLAAs were also considered for the RPV. Those calculations and analyses meeting the criteria for TLAAs are addressed in section 4 of the LRA.

SNC has evaluated the BWRVIP for its applicability to the Hatch Units 1 and 2 design, construction and operating experience. SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch RPV and internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

The applicable portions of the BWRVIP for the RPV implemented at Plant Hatch employs the BWRVIP as documented in the NRC Safety Evaluation Reports (SERs).

Table C.2.1.1-1 RPV BWRVIP Document Applicability[1]

Component	Reference
Shell and Heads	BWRVIP-74 (ref 1)
Nozzles (Including safe ends and thermal sleeves)	BWRVIP-74
Appurtenances	BWRVIP-74 ASME Section XI
Penetrations	BWRVIP-27 (ref 2)
Attachments and Connecting Welds Shroud support weld Jet Pump pad weld Closure studs and support skirt	BWRVIP-38 (ref 3) BWRVIP-41 (ref 4) BWRVIP-48 (ref 5) BWRVIP-74 (ref 1)

Notes:

1. The BWRVIP Documents listed are incorporated by reference into the Hatch LRA. Program commitments residing outside of the BWRVIP are excluded from this table.

Table C.2.1.1-2 Aging Management Program Assessment, RPV: Crack Initiation and Growth due to Stress Corrosion Cracking

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and RPV Monitoring Program provide specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate cracking due to SCC by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The RPV Monitoring Program provides specific acceptance criteria related to cracking within the RPV.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides for inspections and testing of RPV components on a set schedule approved by the NRC.
5. Monitoring and trending for timely corrective actions.	The RPV Monitoring Program provides for compilation of information concerning cracking of RPV components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides water chemistry parameters related to cracking within the RPV due to SCC. The RPV Monitoring Program provides detailed acceptance criteria for the RPV.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, and Reactor Pressure Vessel Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-3 Aging Management Program Assessment, RPV: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program and RPV Monitoring Program provide specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Monitoring the actual CUF with the Component Cyclic or Transient Limit Program will give plant personnel the information needed to provide adequate assurance concerning the continued capability of the RPV to perform its intended function. The RPV Monitoring Program provides specific acceptance criteria related to cracking within the RPV.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides a means for determining the amount of significant crack initiation or growth within the RPV due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of the RPV. The RPV Monitoring Program provides for compilation of data concerning cracking of RPV components.
6. Acceptance criteria are included.	The RPV Monitoring Program and the Component Cyclic or Transient Limit Program provide detailed acceptance criteria related to the cracking of the RPV due to thermal fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Pressure Vessel Monitoring Program, and Component Cyclic or Transient Limit Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-4 Aging Management Program Assessment, RPV: Loss of Fracture Toughness due to Irradiation Embrittlement

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RPV Monitoring Program provides specific limitations and acceptance criteria related to operation and inspection of the RPV.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The RPV Monitoring Program monitors parameters intended to manage loss of fracture toughness within RPV components.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RPV Monitoring Program provides a means for assuring that no loss of fracture toughness within the RPV initiated by irradiation embrittlement has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The RPV Monitoring Program provides for compilation of information concerning loss of fracture toughness of RPV components.
6. Acceptance criteria are included.	The RPV Monitoring Program provides detailed acceptance criteria related to loss of fracture toughness within the RPV due to irradiation embrittlement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Reactor Pressure Vessel Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The RPV Monitoring Program provides a means for collection and analysis of industry wide operating experiences related to the RPV. The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.2 Aging Management Review for the Reactor Pressure Vessel Internals

The reactor pressure vessel internals requiring an aging management review consist of the following components:

- Shroud and repair hardware
- Shroud support
- Core spray spargers and internal piping
- Top guide - Unit 1 only (Unit 2 has wedges and will not lift even with completely cracked holddown assemblies)
- CRD housing and control rod guide tubes
- Jet pump assemblies

The reactor pressure vessel internals (RPV Internals) are constructed from carbon low alloy steel, cast, wrought, and forged austenitic stainless steels, and nickel based alloys.

Systems

B11 – Reactor Assembly (2.3.1.1)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC) and fatigue

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Boiling Water Reactor Vessel Internals Program (BWRVIP)* (A.1.15)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking

Reactor Water Chemistry Control serves to manage cracking due to SCC by controlling electrochemical corrosion potential (ECP) in accordance with the recommendations of EPRI BWR water chemistry guidelines." This can be accomplished through the use of filter / demineralizers which limit halides and other impurities within the feedwater and hydrogen injection which minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* and BWRVIP provide for detailed volumetric, surface, and visual examinations of RPV Internals, thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate stress corrosion cracking within the RPV Internals. ISI Program inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Fatigue

The *ISI Program* and BWRVIP provide for detailed volumetric, surface, and visual examinations of RPV Internals, thereby ensuring that no significant crack initiation and growth due to fatigue has occurred. ISI Program inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

The operating experience for the Hatch internals was reviewed. Over time there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installation of a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the nonsafety related steam dryers. Some have been repaired while others are monitored. Jet pump inspections have resulted in minor indications associated with set-screw gaps, diffuser-to-adapter welds riser pipe welds and tack welds. These are being monitored and reexamined in accordance with the provisions of the BWRVIP. Crack-like indications were also detected in the core shrouds for both units. SNC conservatively decided to installed pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

Applicability of BWRVIP and Commitments to NRC Safety Evaluation Reports

The BWR Vessel and Internals Program (BWRVIP) developed inspection and evaluation reports for internals components and submitted them to NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed the internals relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of the internals for renewal by concluding the rule provisions have been satisfied including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstrating that these programs will assure the functionality of internals into the renewal term. The initial SERs impose the following requirements on a licensee adopting these reports for the renewal term:

- 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 BWRVIP report to manage the effects of aging on the functionality of the reactor vessel during the period of extended operation. 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 BWRVIP 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 10 CFR 54.21(a)(3) and (c)(1).
- 10 CFR 54.21(d) requires that a FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP report for a component(s) shall ensure that the programs and activities specified as necessary in the BWRVIP document are summarily described in the FSAR supplement.
- 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In the BWRVIP report, the BWRVIP stated that there are no generic changes or additions to technical specifications associated with the components as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP reports shall ensure that the inspection strategy described in the BWRVIP document does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal."

This section evaluates the Hatch internals against the above criteria and establishes the acceptability of the internals for the license renewal term. In addition, TLAAs were also considered for the reactor vessel internals. Those calculations and analyses meeting the criteria for TLAAs are addressed in the TLAA section of this application.

SNC has evaluated the BWRVIP for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV internals components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operation parameters; including temperature, pressure, and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. Southern Nuclear has established that the BWRVIP reports bound the Hatch Units 1 and 2 design. SNC has determined the following:

- The components, which require aging management review in accordance with the rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

The BWRVIP for internals implemented at Plant Hatch employs the BWRVIP criteria as documented in the NRC Safety Evaluation Reports (SER).

Table C.2.1.1-5 RPV Internals BWRVIP Document Applicability[1,2]

Component	Reference
Shroud (including repair hardware)	BWRVIP-76 (Ref 6)
Shroud Support	BWRVIP-38 (Ref 3)
Core Spray Piping and Sparger	BWRVIP-18 (Ref 7)
Top Guide - Unit 1	BWRVIP-26 (Ref 8)
Control Rod Guide Tube	BWRVIP-47 (Ref 9)
Jet Pump Assembly	BWRVIP-41 (Ref 4)
CRD Housing	ASME Section XI
Dry Tube	ASME Section XI

Notes:

1. The BWRVIP Documents listed are incorporated by reference into the Hatch LRA. References to ASME Section XI are shown for completeness only and not included within BWRVIP commitments.
2. BWRVIP-76 is the incorporation of BWRVIP-01, BWRVIP-07, and BWRVIP-63 into one document.

Table C.2.1.1-6 Aging management Program Assessment, RPV Internals: Crack Initiation and Growth Due to Stress Corrosion Cracking[1]

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, ISI Program, and Boiling Water Reactor Vessel Internals Programprovide specific limitations and acceptance criteria related to operation and inspection of the RPV Internals.
2. Preventive actions to mitigate or prevent aging degradation.	The Reactor Water Chemistry Control is designed to mitigate cracking due to SCC by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Reactor Water Chemistry Control monitors ECP within the reactor water systems. This parameter is directly linked to mitigation of cracking due to SCC. The ISI Program and BWRVIP provide specific acceptance criteria related to cracking within the RPV Internals.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and BWRVIP provide for inspections and testing of the RPV Internals on a set schedule approved by the NRC.
5. Monitoring and trending for timely corrective actions.	Reactor Water Chemistry Control monitors and trends data to provide adequate assurance the quality of reactor grade water is maintained in accordance with industry standards. The ISI Program and BWRVIP provide for compilation of information concerning cracking of the RPV Internals.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides water chemistry parameters related to cracking within the RPV due to SCC. The ISI Program and BWRVIP provide detailed acceptance criteria for the RPV Internals.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Reactor Water Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The ISI Program and BWRVIP provide confirmation that the current Reactor Water Chemistry Control in place is adequate to mitigate cracking within the RPV Internals during the period of extended operation.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Notes:

1. References to the BWRVIP in this table are shown for completeness only. Actual commitments to BWRVIP documents are contained in Table C.2.1.1-5.

Table C.2.1.1-7 Aging management Program Assessment, RPV Internals Crack Initiation and Growth Due to Fatigue[1]

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The BWRVIP and ISI Program provide specific acceptance criteria related to operation and inspection of the reactor pressure vessel internals.
2. Preventive actions to mitigate or prevent aging degradation.	None
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program and BWRVIP provide for inspections capable of detecting significant crack initiation and growth due to fatigue.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and BWRVIP provide a means for determining that no cracking within the reactor pressure vessel internals due to fatigue has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The ISI Program and BWRVIP monitor parameters linked to crack initiation and growth due to fatigue of RPV Internals.
6. Acceptance criteria are included.	The BWRVIP and ISI Program provide detailed acceptance criteria related to the cracking of the reactor pressure vessel internals due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program provides a method for tracking and resolving deficiencies
8. Confirmation process is included.	The ISI Program and BWRVIP provide confirmation that no significant crack initiation or growth of the reactor pressure vessel internals due to fatigue has occurred or is occurring.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Notes:

1. References to the BWRVIP in this table are shown for completeness only. Actual commitments to BWRVIP documents are contained in Table C.2.1.1-5.

C.2.1.1.3 Aging Management Review for Class 1 Carbon Steel Components Within the Reactor Water Environment

This commodity group includes carbon steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Flow nozzles
- Restricting Orifice

Systems

B21 – Nuclear Boiler System (2.3.1.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, erosion corrosion, and wear and fretting.
- *Cracking* (C.1.2.1.2) due to fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Galvanic Susceptibility Inspections* (A.3.1)
- *Component Cyclic or Transient Limit Program* (A.1.12)
- *Flow Accelerated Corrosion Program (FAC Program)* (A.2.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to general corrosion, galvanic corrosion, pitting, and crevice corrosion by limiting conductivity, concentrations of impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers which limit halides and other impurities within the feedwater, and hydrogen injection, which minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for visual examinations of a representative number of components (such as pump casings and large bore valves) within this commodity group, thereby providing validation that the Reactor Water Chemistry Control Program is adequate to mitigate loss of material. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis to bound any potential loss of material due to galvanic corrosion.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one time examinations of a sentinel population of pipe welds and associated heat affected zones.

Management of Loss of Material due to Wear and Fretting

The *ISI Program* provides for visual examinations of components within this commodity group determined to be susceptible to wear and fretting (such as large bore component flanges), thereby providing validation that any wear or fretting of component mating surfaces is negligible. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material due to Erosion/Corrosion

The *FAC Program* provides for periodic volumetric examination of carbon steel piping components most susceptible to loss of material due to erosion corrosion. Results of inspections are analyzed in order to evaluate the requirements for future inspection locations. The FAC Program elements are based on EPRI recommendations for an effective flow accelerated corrosion program with additional inspections conducted to search for loss of material due to erosion corrosion within piping sections not considered susceptible to "FAC" according to the FAC model.

The *ISI Program* provides for visual examinations of components within this commodity group which may be susceptible to erosion/corrosion (such as pump casings and large bore valve bodies). These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to fatigue is maintained. This program is applicable to Class 1 components larger than NPS 1. No aging management program is required to manage fatigue of Class 1 components NPS 1 and under. Cracking of these components due to fatigue is managed through time limited aging analyses (See section 4.2.2 of the LRA).

The *ISI Program* provides for detailed surface and visual examinations of components within this plant commodity group, thereby ensuring that no significant crack initiation and growth due to thermal fatigue has occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the B21 system. These deficiencies were screened to determine which ones might be potentially age-related. The age related deficiencies identified were determined to be the result of loss of material due to erosion corrosion. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the licensee had implemented an effective program to maintain high energy carbon steel piping systems within acceptable wall thickness limits.

Table C.2.1.1-8 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, and Crevice Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections provide for visual, surface, and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in carbon steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, the ISI Program, Galvanic Susceptibility Inspections, and Treated Water Systems Inspections provide detailed acceptance criteria related to the loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-9 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Wear and Fretting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group susceptible to wear and fretting.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual inspections of components within this plant commodity group that would detect any significant loss of material due to wear and fretting.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the rate of material loss or degradation within components susceptible to wear and fretting.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in carbon steel components.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within mechanical closures.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-10 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Erosion/Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The FAC Program and ISI Program govern aging management of erosion/corrosion related aging for Class 1 carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The FAC Program monitors wall thickness, hydraulic conditions, and process temperatures to estimate potential rates of material loss within susceptible components and systems. The ISI Program inspects surface conditions to provide adequate assurance that no loss of material due to erosion corrosion has occurred within valve bodies and pump casings.
4. The method of detection of the aging effects is described and performed in a timely manner.	The FAC Program provides for periodic inspections of components susceptible to erosion/corrosion and similar mechanisms. The ISI Program provides for periodic visual inspection of valve bodies and pump casings.
5. Monitoring and trending for timely corrective actions.	The FAC Program monitors and trends wall thickness degradation due to erosion/corrosion and similar mechanisms. ISI Program inspections require proper corrective actions be initiated any time an unacceptable condition is noted.
6. Acceptance criteria are included.	The FAC Program and ISI Program provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, FAC Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-11 Aging Management Program Assessment, Class 1 Carbon Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The <u>Component Cyclic or Transient Limit Program</u> and <u>ISI Program</u> govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Monitoring the actual CUF with the Components Cyclic or Transient Limit Program will give plant personnel the information needed to provide adequate assurance concerning the continued capability of Class 1 piping to perform its intended function. The ISI Program provides for inspections of components in this commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining the amount of significant crack initiation or growth within components due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of carbon steel components due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The <u>Corrective Actions Program</u>, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program Provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.4 Aging Management Review for Class 1 Wrought and Forged Stainless Steel Components Within the Reactor Water Environment

This commodity group includes wrought and forged austenitic stainless steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping along with associated welds and weld overlays
- Valve bodies
- Thermowells
- Flow nozzles
- Crack growth monitor
- Restricting orifice

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion and pitting.
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to pitting, crevice corrosion, by limiting conductivity, impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for visual examinations of selected components within this commodity group (such as large bore valves), thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate loss of material due to pitting and crevice corrosion. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Since small bore Class 1 components are exempt from ASME Section XI and Generic Letter 88-01 inspections, a one time inspection of small bore, Class 1, stainless steel piping will be conducted via *Treated Water Systems Piping Inspections*. This activity will conduct appropriate examinations on a sentinel population of small-bore components to validate the adequacy of Reactor Water Chemistry Control.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Reactor Water Chemistry Control serves to manage cracking due to SCC and IGA by controlling electrochemical corrosion potential (ECP) in accordance with EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter / demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for detailed volumetric, surface, and visual examinations of components within this commodity group, thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate cracking due to SCC and IGA. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1 and Generic Letter 88-01 requirements included within the ISI Program.

Since small bore Class 1 components are exempt from ASME Section XI and Generic Letter 88-01 inspections, a one time inspection of small bore, Class 1, stainless steel piping will be conducted via *Treated Water Systems Piping Inspections*. This activity will conduct appropriate examinations on a sentinel population of small-bore components to validate the adequacy of Reactor Water Chemistry Control.

Management of Cracking due to Fatigue

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to thermal fatigue is maintained. This program is applicable to Class 1 components larger than NPS 1. No aging management program is required to manage thermal fatigue of Class 1 components NPS 1 and under. Cracking of these components due to thermal fatigue is managed through time limited aging analyses (See section 4.2.2).

The *ISI Program* provides for detailed volumetric, surface, and visual examinations of components within this plant commodity group, thereby providing adequate assurance that no significant crack initiation and growth due to fatigue has occurred. Inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1 and Generic Letter 88-01 requirements included within the ISI Program.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21 and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found.

While no significant failure trends were found within the prior 5 years, the recirculation system piping has experienced significant age related degradation due to intergranular stress corrosion cracking (IGSCC) of weld heat affected zones. Specifically, the Unit 1 piping components have undergone extensive weld overlay repair and the Unit 2 piping has been replaced with 316NG stainless steel. The primary contributor to these IGSCC failures is dissolved oxygen content. Prior to initiation of hydrogen injection, higher levels of dissolved oxygen produced by radiolysis within the core region created an oxidizing environment conducive to IGSCC. Implementation of hydrogen water chemistry has effectively arrested existing IGSCC induced cracks and has prevented new cracks from forming. Therefore, the current *Reactor Water Chemistry Control* in conjunction with other mitigative activities has proven itself effective in mitigating failures by IGSCC.

Table C.2.1.1-12 Aging Management Program Assessment, Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Loss of Material due to Pitting and Crevice Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, the ISI Program, and the Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program and Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in stainless steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, Treated Water Systems Piping Inspections, and the ISI Program provide detailed acceptance criteria related to the loss of material within stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-13 Aging Management Program Assessment Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting impurities and dissolved oxygen content.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program and Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of information concerning cracking of stainless steel components.
6. Acceptance criteria are included.	Reactor Water Chemistry Control provides detailed acceptance criteria related to the cracking within stainless steel components. The ISI Program and Treated Water Systems Piping Inspections provide acceptance criteria for cracking within selected components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, ISI Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-14 Aging Management Program Assessment, Class 1 Wrought and Forged Stainless Steels Within the Reactor Water Environment: Crack Initiation and Growth due to Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program and ISI Program govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Component Cyclic or Transient Limit Program monitors plant events that could contribute to an increase in CUF, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for tracking the amount of significant crack initiation or growth within stainless steel components due to fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of stainless steels due to fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.5 Aging Management Review for Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment

This commodity group includes cast austenitic stainless steel components located within the Class 1 boundary and exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Pump casings and covers
- Valve bodies

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion, pitting, and wear and fretting.
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and fatigue.
- *Loss of fracture toughness* (C.1.2.1.3) due to thermal embrittlement

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Component Cyclic or Transient Limit Program* (A.1.12)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting and Crevice Corrosion

Reactor Water Chemistry Control serves to manage loss of material due to pitting and crevice corrosion by limiting conductivity, concentrations of impurities, and dissolved oxygen per EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *ISI Program* provides for detailed examinations of large bore components within this commodity group (such as pump casings and valve bodies), thereby providing validation that Reactor Water Chemistry Control is adequate to mitigate loss of material due to pitting and crevice corrosion. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material due to Wear and Fretting

The *ISI Program* provides for detailed visual examinations of components within this commodity group determined to be susceptible to wear and fretting (such as large bore component flanges), thereby providing validation that any wear or fretting of component mating surfaces is negligible. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Because this not an aggressive aging effect, *Reactor Water Chemistry Control* serves to manage cracking due to SCC and IGA by controlling electrochemical corrosion potential (ECP) in accordance with the EPRI BWR water chemistry guidelines. This is accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

Management of Cracking due to Fatigue

Plant Hatch is committed to upgrading its Reactor Recirculation Pump shafts and covers to a later design to minimize the potential for thermal cycling and cracking due to thermal fatigue within the recirculation pump covers and integral heat exchangers.

Cracking of Byron Jackson recirculation pump covers has been observed in many plants since the early 1980's. This cracking is due to thermal cycling that occurs where process water and seal injection water mix. In response to this concern, Plant Hatch changed out the Unit 1 and 2 recirculation pump rotating assemblies and covers to an upgraded design in 1990 and 1991, respectively. Subsequently, Borg Warner / International Products determined that the new designs were still susceptible to cracking due to thermal cycling. To resolve this problem, Plant Hatch has committed to again, prior to entering the renewal period, replace the covers with the latest design, which incorporates a new heat exchanger design. Testing on this new design has not revealed any cracking due to thermal cycling.

The *Component Cyclic or Transient Limit Program* at Plant Hatch monitors thermal cycles and periodically recalculates the cumulative usage factor for several bounding locations within Class 1 components to verify that adequate margin against cracking due to fatigue is maintained. Also, see section 4.2.2 of the application.

The *ISI Program* provides for surface and visual examinations of components within this plant commodity group, thereby ensuring that no significant crack initiation and growth due to fatigue has occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Fracture Toughness Due to Thermal Embrittlement

The *ISI Program* provides for surface and visual examinations of components within this commodity group, thereby providing assurance that cracking of components as a result of loss of fracture toughness has not occurred. These inspections are accomplished in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found.

Table C.2.1.1-15 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Pitting and Crevice Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and the ISI Program govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity impurities and dissolved oxygen.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual, surface, and volumetric inspections of components within this plant commodity group.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within cast stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in cast stainless steel components.
6.	Acceptance criteria are included.	Reactor Water Chemistry Control and the ISI Program provide detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, ISI Program, and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-16 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Wear and Fretting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group susceptible to wear and fretting.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the rate of material loss or degradation within components susceptible to wear and fretting.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in stainless steel components.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within mechanical closures.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides adequate assurance that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-17 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control governs aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting impurities and dissolved oxygen content.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	Reactor Water Chemistry Control sufficiently mitigates the aging effect such that this attribute is not required.
4.	The method of detection of the aging effects is described and performed in a timely manner.	Reactor Water Chemistry Control sufficiently mitigates the aging effect such that this attribute is not required.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6.	Acceptance criteria are included.	Reactor Water Chemistry Control provides detailed acceptance criteria related to the cracking of stainless steels due to IGA and SCC.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventative actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-18 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to Thermal Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Component Cyclic or Transient Limit Program, and ISI Program govern aging management for cracking in the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program mitigates cracking by monitoring the events that determine the actual CUF for Class 1 components. The Component Cyclic or Transient Limit Program enables prediction of potentially hazardous fatigue through the comparison of the actual CUF with the allowable CUF.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Component Cyclic or Transient Limit Program monitors plant events that could contribute to an increase in CUF, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining the amount of significant crack initiation or growth within cast stainless steel components due to thermal fatigue that has occurred or is occurring. The Component Cyclic or Transient Limit Program requires trending of the actual CUF in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program provides for trending of total CUF, thereby providing a method to evaluate what corrective actions need to be implemented prior to significant degradation of components. The ISI Program provides for compilation of data concerning cracking of Class 1 components.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program and ISI Program provide detailed acceptance criteria related to the cracking of cast stainless steels due to thermal fatigue.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Component Cyclic or Transient Limit Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-19 Aging Management Program Assessment, Class 1 Cast Austenitic Stainless Steel Components Within the Reactor Water Environment: Loss of Fracture Toughness due to Thermal Embrittlement

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program includes the Class 1 components within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for periodic visual, surface, and volumetric inspections of Class 1 system components.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for determining that no loss of fracture toughness within cast stainless steel components due to thermal embrittlement has occurred or is occurring.
5. Monitoring and trending for timely corrective actions.	The ISI Program compiles data concerning inspection results for Class 1 components.
6. Acceptance criteria are included.	The ISI Program provides detailed acceptance criteria related to the loss of fracture toughness within stainless steels due to thermal embrittlement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.1.1.6 Aging Management Review for Class 1 Pressure Boundary Bolting

This commodity group includes Class 1 Pressure Boundary Bolting. This bolting is fabricated from low alloy carbon steel.

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- B31 – Reactor Recirculation (2.3.2.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.7.1) due to pitting and crevice corrosion.
- *Loss of preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Torque Activities* (A.1.11)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Preload

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within Class 1 fasteners. These torque activities meet the intent of EPRI degradation and failure of bolting in nuclear power plants that was generally endorsed by the NRC in NUREG 1339, "Resolution of GSI 29."

The *ISI Program* provides for volumetric and surface inspections of certain large diameter fasteners and visual inspection of bolted closure integrity via operating pressure testing. These inspections provide validation that improper preload has not caused a failure of the bolting. These inspections are conducted in accordance with ASME Section XI, Table IWB-2500-1.

Management of Loss of Material

The *ISI Program* provides for visual, surface, and volumetric inspections of Class 1 fasteners. These inspections are adequate to detect any significant loss of material due to corrosion within the fasteners. These inspections are conducted in accordance with ASME Section XI, Table IWB-2500-1.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21 and B31 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope B21 and B31 components, applicable to this plant commodity group, were found. However, several instances of leaking bolted closures were found during pressure testing conducted prior to Drywell closure. These leaks were minor and in the majority of cases may be attributed to the thermal effects associated with cool-down of the Class 1 systems for outages. In all cases, these leaks were corrected in accordance with Plant Hatch's implementation of ASME Section XI within the ISI Program. Activities performed in accordance with vendor service information letters also contribute to the overall reduction of these leaks. Operating experience with CRD flange bolts indicates numerous instances of pitting and crevice corrosion. These conditions were discovered during ISI Program Inspections. All fasteners demonstrating evidence of corrosion were replaced.

Table C.2.1.1-20 Aging Management Program Assessment, Class 1 Pressure Boundary Bolting: Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities and ISI Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The ISI Program provides for visual and volumetric inspections of components within this plant commodity group.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program provides a means for evaluating the adequacy of current Torque Activities in preventing loss of preload within Class 1 fasteners during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of information concerning loss of preload within Class 1 fasteners.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement. The ISI Program provides acceptance criteria for acceptable pressure test results.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Torque Activities, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.1.1-21 Aging Management Program Assessment, Class 1 Pressure Boundary Bolting: Loss of Material due to Crevice Corrosion and Pitting

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	Periodic inspections of Class 1 fasteners conducted in accordance with the ISI program are adequate to detect significant loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	The ISI Program provides for compilation of data concerning loss of material in Class 1 fasteners.
6. Acceptance criteria are included.	The ISI Program provides acceptance criteria for loss of material within Class 1 fasteners.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent reoccurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrective and preventative actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2 AGING MANAGEMENT REVIEWS FOR NON-CLASS 1 MECHANICAL DISCIPLINE COMMODITIES

C.2.2.1 Non-Class 1 Components Reactor Water Environment Description

Components within section C.2.2.1 are subject to an environment of reactor water under normal conditions. The reactor water environment is defined in section C.1.2.1.

C.2.2.1.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Reactor Water Environment

This commodity group includes carbon steel exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Steam traps
- Strainers
- Preheater
- Condenser shell

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N61 – Main Condenser (2.3.5.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion.
- *Cracking* (C.1.2.1.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Flow Accelerated Corrosion Program (FAC Program)* (A.2.2)

- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management in the renewal term identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

Reactor Water Chemistry Control serves to manage loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion and MIC by limiting conductivity, impurities, and dissolved oxygen per the recommendations EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Loss of Material due to Erosion Corrosion

The *FAC Program* provides for periodic volumetric examination of carbon steel piping components most susceptible to loss of material due to erosion corrosion. Results of inspections are analyzed in order to evaluate the requirements for future inspection locations. The FAC Program elements are based on EPRI recommendations for an effective flow accelerated corrosion program with additional inspections conducted to search for loss of material due to erosion corrosion within piping sections not considered susceptible to "FAC" according to the FAC model.

The *Treated Water Systems Piping Inspections* provide for one-time examination of carbon steel piping components most susceptible to loss of material due to erosion-corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the applicable system. These deficiencies were screened to determine which ones might be potentially age-related. Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system. This experience validates the conclusion that erosion corrosion can occur in areas not identified by the FAC model. The *FAC Program* and *Treated Water Systems Piping Inspections* will specifically target these suspect areas for increased inspections such that future loss of component function is minimized. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the licensee had implemented an effective program to maintain high energy carbon steel piping systems within acceptable wall thickness limits.

Table C.2.2.1-1 Aging Management Program Assessment, Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Reactor Water Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections, and the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, the Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.1-2 Aging Management Program Assessment: Carbon Steel Components Within the Reactor Water Environment: Loss of Material due to Erosion Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The FAC Program and Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the FAC Program provides for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The FAC Program and Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5. Monitoring and trending for timely corrective actions.	The FAC Program monitors and trends wall thickness degradation due to erosion corrosion and similar mechanisms.
6. Acceptance criteria are included.	The FAC Program and Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, FAC Program, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program ensures that corrosion rates within erosion corrosion susceptible components are adequately identified and trended.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.1.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Reactor Water Environment

This commodity group includes wrought and forged austenitic stainless steel exposed to an internal environment of Reactor Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Thermowells
- Restricting orifices
- Preheater
- Steam Trap
- Strainer

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N32 – Electro-Hydraulic Control (2.3.5.1)
- N61 – Main Condenser (2.3.5.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.1.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.1.2) due to stress corrosion cracking (SCC), intergranular attack (IGA), and thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Reactor Water Chemistry Control* (A.1.1)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

Reactor Water Chemistry Control serves to manage loss of material due to pitting, crevice corrosion, or MIC by limiting conductivity, impurities and dissolved oxygen per the recommendations of the EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Treated Water Systems Piping Inspections* serves to validate the adequacy of reactor water chemistry control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Reactor Water Chemistry Control serves to manage cracking due to stress corrosion cracking and intergranular attack by controlling electrochemical corrosion potential in accordance with the recommendations of the EPRI BWR water chemistry guidelines. This can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. Reactor water quality is continuously monitored and corrective actions are taken in the event that any limits are exceeded.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating cracking within stainless steel piping components by performing one-time examinations of a sentinel population of pipe welds and associated heat affected zones.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the B21, E41, E51, N32, and N61 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.1-3 Aging Management Program Assessment, Stainless Steel Components Within the Reactor Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control and the Treated Water Systems Piping Inspections govern aging management for the commodities included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Treated Water Systems Piping Inspections, and Reactor Water Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.1-4 Aging Management Program Assessment, Stainless Steel Components Within the Reactor Water Environment: Crack Initiation and Growth due to IGA and SCC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Reactor Water Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, impurities, and dissolved oxygen.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Reactor Water Chemistry Control standards in preventing cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the cracking of stainless steels due to IGA and SCC.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Reactor Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2 Non-Class 1 Components Demineralized Water Environment Description

Components within section C.2.2.2 are subject to an internal environment of demineralized water under normal conditions. The demineralized water environment is defined in section C.1.2.2.

C.2.2.2.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Demineralized Water Environment

This commodity group includes carbon steel components and exposed to an internal environment of Demineralized Water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Pump casings
- Accumulators
- Expansion Tank
- Thermowells

Systems

- C11 – Control Rod Drive (2.3.4.1)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)

Aging Effects Requiring Management

Loss of material (C.1.2.2.1) due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion.

Cracking (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, MIC, and Crevice Corrosion

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to manage loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of impurities, total organic carbon, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating the loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Management of Loss of Material due to Erosion Corrosion

The *Treated Water Systems Piping Inspections* provide for one-time examination of carbon steel piping components most susceptible to loss of material due to erosion-corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the C11, E41, E51, R43, and T23 systems. These deficiencies were screened to determine which ones might be potentially age-related. Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system.

Table C.2.2.2-1 Aging Management Program Assessment, Carbon Steel Components Within the Demineralized Water Environment: Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control, the Treated Water Systems Piping Inspections, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.2-2 Aging Management Program Assessment, Carbon Steel Components Within the Demineralized Water Environment: Loss of Material due to Erosion/Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6.	Acceptance criteria are included.	The Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Demineralized Water Environment

This commodity group includes stainless steel and cast austenetic stainless steel components exposed to an internal environment of demineralized water. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- Thermowells
- Restricting orifices
- Flex Hose

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- C11 – Control Rod Drive (2.3.4.1)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P11 – Condensate Transfer and Storage (2.3.4.5)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and MIC.
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of detrimental impurities, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material within stainless steels by performing appropriate examinations of a sentinel population of the susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.2-3 Aging Management Program Assessment, Stainless Steel Components Within the Demineralized Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this postion.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.2.3 Aging Management Review for Condensate Storage Tanks

This commodity group includes the Unit 1 and Unit 2 condensate storage tanks (CSTs). The Unit 1 tank is constructed of Type 6061-T6 aluminum alloy structural shapes and pipe and Type 5454-O aluminum alloy plate. Nozzle flanges are constructed from ASTM A181 Gr. 1 galvanized carbon steel. The Unit 2 tank is fabricated from wrought and forged austenitic stainless steels.

Systems

P11 – Condensate Transfer and Storage (2.3.4.5)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to galvanic corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Condensate Storage Tank Inspections* (A.3.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Galvanic Corrosion, Pitting, Crevice Corrosion, and MIC

The *Demineralized Water and Condensate Storage Tank Chemistry Control* serves to mitigate loss of material due to galvanic corrosion, pitting, crevice corrosion, or MIC by limiting concentrations of impurities and conductivity within the condensate storage tanks. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and Condensate Storage Tank Chemistry Control implements EPRI BWR water chemistry guidelines.

The *CST Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material. This activity provides for a one time internal inspection of both CSTs including creviced areas and dissimilar metal connections. Inspections conducted are similar to VT-1 examinations.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.2-4 Aging Management Program Assessment: Loss of Material Due to Galvanic Corrosion, MIC, Pitting, and Crevice Corrosion Within the Unit 1 and 2 Condensate Storage Tanks

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and CST Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The CST Inspections provide for visual examination of CST internal surfaces.
4. The method of detection of the aging effects is described and performed in a timely manner.	The CST Inspections provide a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within the Unit 1 and 2 CSTs during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Demineralized Water and Condensate Storage Tank Chemistry Control and CST Inspections provide detailed acceptance criteria related to the loss of material within the Unit 1 and 2 CSTs.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and CST Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.3 Non-Class 1 Components Suppression Pool Water Environment Description

Components within section C.2.2.3 are subject to an environment of suppression pool water under normal conditions. The suppression pool water environment is defined in section C.1.2.2.

C.2.2.3.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Suppression Pool Environment

This commodity group consists of carbon steel commodities with an internal environment of suppression pool water or submerged within the suppression pool. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Pump casings
- Thermowells
- Blind flange

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- T23 – Primary Containment (2.4.3)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and erosion corrosion.
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Suppression Pool Chemistry Control* (A.1.7)
- *Protective Coatings Program* (A.2.3)

- *Torus Submerged Components Inspection Program* (A.3.7)
- *Treated Water Systems Piping Inspections* (A.3.2)
- *Galvanic Susceptibility Inspections* (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, MIC, and Erosion/Corrosion

Suppression Pool Chemistry Control establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. Suppression Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

For components submerged within the suppression pool:

The *Torus Submerged Components Inspection Program* performs periodic inspections of piping and other components within this commodity group which are submerged within the suppression pool to assure that the necessary quality, operability, and safety limits of the systems' intended functions are not compromised by the loss of material. Inspections conducted are similar to VT-1 examinations.

For corrosion of external surfaces, the *Protective Coatings Program* conducts an underwater inspection of the protective coatings of underwater piping included in this commodity group which is submerged within the suppression pool and requires that coatings be repaired if found defective. The Protective Coatings Program is based on the recommendations of ANSI and ASTM coating standards for the nuclear power industry.

For other components (such as piping connected to the suppression pool):

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Suppression Pool Chemistry Control in mitigating the loss of material within small bore carbon steel piping by performing appropriate examinations of a sentinel population of susceptible locations within components that are not submerged.

The *Galvanic Susceptibility Inspections* provides for appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A core spray jockey pump check valve experienced general corrosion to the point where the valve was replaced. The condition was identified as the result of the valve's disc being stuck in position. Thus, no loss of pressure boundary occurred.

RHR check valve internals were identified to have severe loss of material due to cavitation, pitting and erosion. This loss of material was not in the valve's body. The valve was repaired with plans made to replace the valve at the next outage.

Loop A of the RHR minimum flow piping developed a through wall leak. The leak was caused by a loss of material described as general wall degradation with one small distinguishable pit. A small portion of pipe containing the through wall leak was cut out of the line and evaluated for determination of the failure mechanism. It was reported that the hole initiated as a result of MIC and was then completed through ordinary inorganic corrosion. No MIC organisms were found in the cut sample of pipe or in any of several water samples taken from the RHR torus water chamber.

Further root cause analysis of this failure was conducted by Plant Hatch. Additional RHR piping components and a section of core spray minimum flow piping were analyzed. The results indicated that the RHR pipe wall thickness degradation was cause by ancient MIC intrusion of the minimum flow line and the carbon steel surfaces being immersed in stagnant, deoxygenated water. It has been concluded that this MIC intrusion was the result of the length of time it took to construct the plant and how pipe lay-up procedures were administered. The core spray minimum flow piping was reported to have general wall thinning on the bottom half of the entire twenty foot horizontal run of pipe and there was pitting on both sides of the pipe approximately halfway up the wall of the pipe. This damage was indicative of a partially filled piping system exposed to flow and/or standing water.

The corrective action consisted of replacing all pipe and several valves in the immediate vicinity of the through wall leak on RHR piping. It is assumed that the core spray piping removed for analysis was also replaced with new piping. The RHR issue was closed with no further actions required based on the evaluation of the results.

The results of the analysis of the damage to the RHR and core spray minimum flow lines are indicative of the aging mechanisms and the resulting aging effects identified above. Thus, the recommendations to perform internal inspection of the piping systems is substantiated.

Table C.2.2.3-1 Aging Management Program Assessment, Carbon Steel Components Submerged Within the Suppression Pool: Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, Erosion/Corrosion, and MIC.

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program, Torus Submerged Components Inspection Program, and Suppression Pool Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities. The Protective Coatings Program minimizes loss of material by maintaining the applied surface coatings.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections, and the Torus Submerged Components Inspection Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program performs visual inspections of the protective coating for deterioration (blistering, peeling, etc.). The Torus Submerged Components Inspection Program provides for periodic visual inspection of component surfaces.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program requires evaluation, and documentation of the visual inspections of the coating program. The Torus Submerged Components Inspection Program provides for compilation of data and identification of trends concerning significant loss of material in submerged components.
6. Acceptance criteria are included.	The Protective Coatings Program requires qualified coating specialists to evaluate visual inspection results of the internal surface protective coatings. Suppression Pool Chemistry Control establishes limits for impurities and conductivity. The TAIP provides detailed acceptance criteria related to the loss of material.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, Protective Coatings Program, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-2 Aging Management Program Assessment, Carbon Steel Components Within the Suppression Pool Water Environment (but not submerged in the suppression pool): Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	The Suppression Pool Chemistry Control is designed to mitigate age-related degradation by limiting conductivity, and impurities.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections, and the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections and Galvanic Susceptibility Inspections provide a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this postion.
6.	Acceptance criteria are included.	The Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within carbon steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-3 Aging Management Program Assessment, Carbon Steel Components Within the Suppression Pool Water Environment: Loss of Material Due to Erosion/Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Treated Water Systems Piping Inspections govern aging management of erosion corrosion related aging for carbon steel components.
2. Preventive actions to mitigate or prevent aging degradation.	Due to the monitoring and trending activities and corrective actions, preventive actions are not specified for this commodity.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for periodic inspections of components susceptible to erosion corrosion and similar mechanisms.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	The Treated Water Systems Piping Inspections provide detailed acceptance criteria for loss of material within carbon steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.3.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Suppression Pool Environment

This group consists of wrought/forged stainless steels and cast austenitic stainless steels with an internal environment of treated water and an external environment of inside or submerged in the suppression pool. Component types included in this commodity group include:

- Strainers
- Piping
- Valve Bodies
- Restricting Orifices
- Tubing
- Conductivity Element
- Thermowell

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to SCC, IGA and thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Suppression Pool Chemistry Control* (A.1.7)
- *Torus Submerged Components Inspection Program* (A.3.7)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Due to Crevice Corrosion, Pitting, and MIC

Suppression Pool Chemistry Control establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. Suppression Pool Chemistry Control implements EPRI BWR water chemistry guidelines.

For Components Submerged with the Suppression Pool:

The *Torus Submerged Components Inspection Program* provides for periodic inspections of the HPCI and RCIC torus suction strainers and piping. This inspection is similar to VT-1 and adequate to detect large scale degradation of components located within the torus, thereby providing indications as to the adequacy of the chemistry program.

For Other Components (Such as Piping Connected to the Suppression Pool):

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Reactor Water Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to SCC and IGA

Cracking due to SCC and IGA applies only to SS components exposed to steam exhaust from SRVs, the HPCI turbine exhaust steam, or the RCIC turbine exhaust steam. *Suppression Pool Chemistry Control* establishes the suppression pool water quality and chemistry acceptance criteria, and limits impurities, providing a degree of mitigation of these corrosion mechanisms. The Suppression Pool Chemistry Control implements EPRI BWR water chemistry guidelines.

The *Torus Submerged Components Inspection Program* performs periodic inspections of piping within the suppression pool. This inspection is similar to VT-1 and adequate to detect large scale degradation of components located within the torus, thereby providing indications as to the adequacy of the chemistry program.

Management of Cracking Due To Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written on these systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of the in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.3-4 Aging Management Program Assessment, Stainless Steel Components Submerged Within the Suppression Pool: Loss of Material Due To Crevice Corrosion, Pitting, And MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Suppression Pool Chemistry Control and Torus Submerged Components Inspection Program govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Torus Submerged Components Inspection Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Torus Submerged Components Inspection Program provides a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	The Torus Submerged Components Inspection Program provides for compilation of data and identification of trends concerning significant loss of material in submerged components.
6.	Acceptance criteria are included.	Suppression Pool Chemistry Control and the Torus Submerged Components Inspection Program provide detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-5 Aging Management Program Assessment, Stainless Steel Components Within the Suppression Pool Environment (but not submerged in the suppression pool): Loss of Material Due To Crevice Corrosion, Pitting, And MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Suppression Pool Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6.	Acceptance criteria are included.	Suppression Pool Chemistry Control provides detailed acceptance criteria related to the loss of material within stainless steels. The Treated Water Systems Piping Inspections provides acceptance criteria for loss of material within stainless steel components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.3-6 Aging Management Program Assessment, Stainless Steel Components Submerged Within the Suppression Pool: Cracking Due to SCC and IGA

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control and Torus Submerged Components Inspection Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by controlling fluid purity and composition.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Torus Submerged Components Inspection Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torus Submerged Components Inspection Program provides a means for evaluating the adequacy of current Suppression Pool Chemistry Control standards in mitigating cracking within stainless steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The Torus Submerged Components Inspection Program provides for compilation of information concerning degradation of stainless steel components.
6. Acceptance criteria are included.	Suppression Pool Chemistry Control provides detailed acceptance criteria related to the loss of material within stainless steels. The Torus Submerged Components Inspection Program provides acceptance criteria for degradation of stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, and Torus Submerged Components Inspection Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.4 Non-Class 1 Components Borated Water Environment Description

Components within section C.2.2.4 are subject to an environment of borated water under normal conditions. The borated water environment is described in section C.1.2.2.

C.2.2.4.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Borated Water Environment

This commodity group includes carbon steel components exposed to an internal environment of borated water and includes only the standby liquid control system ASME Section VIII accumulators. The inner surfaces of these accumulators are coated with a phenolic resin.

Systems

C41 – Standby Liquid Control (2.3.3.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to general corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Pitting, Crevice Corrosion, and MIC

The *Protective Coatings Program* provides for periodic inspection of the phenolic resin coating on the interior surfaces of the accumulator. Provided this coating remains intact, no aging of the accumulator surfaces is expected due to the excellent protective properties provided by the coating material.

Demineralized Water and Condensate Storage Tank Chemistry Control serves to mitigate loss of material within the standby liquid control system accumulators by minimizing the contaminants to which the phenolic resin liner is exposed.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable system. These deficiencies were screened to determine which ones might be potentially age-related. No significant age-related failures of in-scope components, applicable to this plant commodity group, were found. However, isolated instances of foreign material intrusion were noted and corrected via the *Corrective Actions Program*.

Table C.2.2.4-1 Aging Management Program Assessment, Carbon Steel Components Within the Borated Water Environment: Loss of Material due to General Corrosion, Pitting, Crevice Corrosion, and MIC.

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program and Demineralized Water and Condensate Storage Tank Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities. The Protective Coatings Program minimizes loss of material by maintaining the applied inner surface coating.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program provides a means to perform visual inspection of the accumulator's internal protective coating for deterioration (blistering, peeling, etc.).
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program requires evaluation, and documentation of the visual inspections of the applied coating.
6. Acceptance criteria are included.	The Protective Coatings Program requires qualified coating specialists to evaluate visual inspection results of the internal surface protective coatings. Demineralized Water and Condensate Storage Tank Chemistry Control provides detailed acceptance criteria related to the loss of material.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides a means for control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides a means for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.4.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Borated Water Environment

This commodity group includes stainless steel components exposed to an internal environment of borated water. The following component types are included within this evaluation:

- Storage tank
- Piping
- Valve bodies
- Thermowells
- Pump casing

Systems

C41 – Standby Liquid Control (2.3.3.1)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.2.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Demineralized Water and Condensate Storage Tank Chemistry Control* (A.1.6)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and MIC

Demineralized Water and Condensate Storage Tank Chemistry Control serves to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting detrimental impurities, and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded. Demineralized Water and

Condensate Storage Tank Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Demineralized Water and Condensate Storage Tank Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found. However, isolated instances of foriegn material intrusion were noted and corrected via the Corrective Actions Program.

Table C.2.2.4-2 Aging Management Program Assessment, Stainless Steel Components Within the Borated Water Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	The Demineralized Water and Condensate Storage Tank Chemistry Control is designed to mitigate age-related degradation by limiting conductivity and impurities.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Demineralized Water and Condensate Storage Tank Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6.	Acceptance criteria are included.	The Demineralized Water and Condensate Storage Tank Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Demineralized Water and Condensate Storage Tank Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5 Non-Class 1 Components Closed Cooling Water Environment Description

Closed cooling water is used within the reactor building closed cooling water (RBCCW) system and primary containment chilled water (PCCW) system. A description of closed cooling water is provided in section C.1.2.3.

C.2.2.5.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Closed Cooling Water Environment

This commodity group includes carbon steel components exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Heat exchanger shells.

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Primary Containment Chilled Water (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, erosion/corrosion, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic Corrosion, Pitting, Crevice Corrosion, MIC, and Erosion Corrosion

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The Treated Water Systems Piping Inspections serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within carbon steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. Minimal age-related deficiencies of the in-scope P42 and P64 components were found. Failures related to general corrosion of carbon steel valve bodies exposed to condensation and leakage. Insulated and uninsulated external surfaces are addressed in section C.2.4.1.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-1 Aging Management Program Assessment, Carbon Steel Components Within the Closed Cooling Water Environment: Loss of Material Due to General Corrosion, Galvanic Corrosion, Erosion corrosion, Crevice Corrosion, Pitting, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Closed Cooling Water Chemistry Control standards in mitigating loss of material within carbon steel components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Closed Cooling Water Environment

This commodity group includes stainless steel components exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- Thermowells
- Piping
- Valve bodies
- Flexible connectors
- Flow elements

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Primary Containment Chilled Water (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Crevice Corrosion, Pitting, and MIC

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within stainless steel piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related deficiencies of the in-scope P42 and P64 components, applicable to this plant commodity group, were found.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-2 Aging Management Program Assessment, Stainless Steel Components Within the Closed Cooling Water Environment: Loss of Material Due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provides a means for evaluating the adequacy of current Closed Cooling Water Chemistry Control standards in mitigating loss of material within stainless steel components during the period of extended operation.
5.	Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6.	Acceptance criteria are included.	Closed Cooling Water Chemistry Control and the Treated Water Systems Piping Inspections provide detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.5.3 Aging Management Review for Non-Class 1 Copper Alloy Components Within the Closed Cooling Water Environment

This commodity group includes copper alloys exposed to an internal environment of closed cooling water. The following component types are included within this evaluation:

- End caps
- Relief valve bases
- Piping
- Temperature probes

Systems

- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P64 – Reactor Building Chilled Water System (2.3.4.10)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.3.1) due to selective leaching and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.3.2) due to thermal fatigue.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Closed Cooling Water Chemistry Control* (A.1.2)
- *Treated Water Systems Piping Inspections* (A.3.2)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Selective Leaching and Microbiologically Influenced Corrosion

Closed Cooling Water Chemistry Control establishes and maintains closed cooling water chemistry in accordance with EPRI closed cooling water chemistry guidelines. Closed cooling water is pH adjusted into the basic range and corrosion inhibitors are added to promote an adherent protective oxide layer and minimize corrosion. Biocides are added to minimize microbiologically influenced corrosion. Levels of detrimental impurities and microbiological organisms are monitored and trended. Corrosion coupons are utilized to provide indications of general corrosion rates.

The *Treated Water Systems Piping Inspections* serve to validate the adequacy of Closed Cooling Water Chemistry Control in mitigating loss of material within copper alloy piping components by performing one-time examinations of a sentinel population of susceptible locations.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the P42 and P64 systems. These deficiencies were screened to determine which ones might be potentially age-related. Minimal age-related deficiencies of the in-scope P42 and P64 components were found.

The closed cooling water chemistry program has extensive operating history demonstrating quality improvements made based on past problems. The Hatch Chemistry Program description contains a discussion of this history.

Closed cooling water (CCW) system chemistry at Plant Hatch has become very complex over the years. Originally there were fewer systems to analyze and not many chemical analyses were performed. Now there are 11 systems and 14 different analyses (plus coupons on RBCCW). Significant changes in the sampling and analysis program have been made based on internally identified deficiencies.

Table C.2.2.5-3 Aging Management Program Assessment, Copper Alloy Components Within the Closed Cooling Water Environment: Loss of Material Due to Selective Leaching and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Closed Cooling Water Chemistry Control and Treated Water Systems Piping Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Closed Cooling Water Chemistry Control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Treated Water Systems Piping Inspections provide for visual, surface, and volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Treated Water Systems Piping Inspections provide for detection of loss of material in brass components.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	Closed Cooling Water Chemistry Control and the Treated Water Systems Piping Inspections provide detailed acceptance criteria related to loss of material in brass components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Closed Cooling Water Chemistry Control, and Treated Water Systems Piping Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6 Non-Class 1 Components River Water Environment Description

River water consists of water taken directly from the Altamaha River for use as cooling water for various systems. See section C.1.2.4 for a description of the river water environment.

C.2.2.6.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the River Water Environment

This commodity group includes carbon steel components exposed to an internal environment of river water. The following component types are included within this evaluation:

- Piping
- Valve bodies
- Strainer bodies
- Discharge venturies
- Sight glass bodies
- Thermowells
- Pump discharge columns
- Pump discharge heads

Systems

- W33 – Traveling Water Screen, Trash Racks (2.3.4.16)
- P41 – Plant Service Water (2.3.4.7)
- E11 – Residual Heat Removal (2.3.3.2)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1) due to general corrosion, galvanic corrosion, erosion corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and fouling.
- *Cracking* (C.1.2.4.2) due to thermal fatigue.
- *Flow blockage* (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)

- Structural Monitoring Program (A.2.5)
- Galvanic Susceptibility Inspections (A.3.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material and Flow Blockage

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *Galvanic Susceptibility Inspections* provides for a one-time examination of carbon steel to stainless steel dissimilar metal welds to evaluate the extent of loss of material due to galvanic corrosion. Inspections will be performed on a worst case basis in order to bound any potential loss of material due to galvanic corrosion.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that 15 deficiencies on E11 and 155 deficiencies on P41 systems were found.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-1 Aging Management Program Assessment, Carbon Steel Components Within the River Water Environment: Loss of Material Due to General Corrosion, Galvanic Corrosion, Crevice Corrosion, Erosion Corrosion MIC, Pitting, and Fouling

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and Galvanic Susceptibility Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the Structural Monitoring Program serve to minimize particulate intrusion into service water systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections; the Galvanic Susceptibility Inspections provide for visual, surface, or volumetric inspections; and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program and Galvanic Susceptibility Inspections provide for periodic inspections of carbon steel components.
5.	Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in carbon steel components.
6.	Acceptance criteria are included.	The PSW and RHRSW Inspection Program, Galvanic Susceptibility Inspections, Structural Monitoring Program, and PSW and RHRSW Chemistry Control provide acceptance criteria related to loss of material in carbon steel components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Structural Monitoring Program, PSW and RHRSW Chemistry Control, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-2 Aging Management Program Assessment, Carbon Steel Components Within the River Water Environment: Flow Blockage Due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program, govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Structural Monitoring Program, PSW and RHRSW Chemistry Control, and Galvanic Susceptibility Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the River Water Environment

This commodity group includes stainless steel and cast austenitic stainless steel components with an internal environment of river water. The following component types are included within this evaluation:

- Piping
- Tubing
- Restricting orifices
- Thermowells
- Strainer baskets
- Flexible connectors
- Valve bodies
- Pump bowl assemblies
- Site glass body

Systems

- E11 – Residual Heat Removal System (2.3.3.2)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1) due to crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and fouling.
- *Cracking* (C.1.2.4.2) due thermal fatigue;
- *Flow blockage* (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

Management of Cracking due to Thermal Fatigue:

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that 15 deficiencies on E11 and 155 deficiencies on P41 systems were found. These deficiencies were screened to determine which ones might be potentially age-related. No age related failures found.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-3 Aging Management Program Assessment, Stainless Steel Components Within the River Water Environment: Loss of Material Due to Crevice Corrosion, MIC, Pitting, and Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and Structural Monitoring Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the Structural Monitoring Program serve to minimize silt and debris intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for periodic inspections of stainless steel components.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in stainless steel components.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to loss of material in stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-4 Aging Management Program Assessment, Stainless Steel Components within the River Water Environment: Flow Blockage Due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Inspection Program, Structural Monitoring Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on compound surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, the Structural Monitoring Program, and the PSW and RHRSW Chemistry Control provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.3 Aging Management Review for Non-Class 1 Copper Alloys Within the River Water Environment

This commodity group includes copper alloy components with an internal environment of river water. The following component types are included within this evaluation:

- Instrumentation tubing
- Valves.

Systems

- E11 – Residual Heat Removal (2.3.3.2)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- Loss of material (C.1.2.4.1) due to selective leaching, galvanic corrosion, microbiologically influenced corrosion (MIC), fouling, and erosion corrosion
- Cracking (C.1.2.4.2) due to thermal fatigue
- Flow Blockage (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1. or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program performs systematic and periodic inspection of plant service water and residual heat removal system components to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition monitoring database mentioned in section 3.0 showed that no age-related failures, relative to this plant commodity group, were noted in the past five years.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-5 Aging Management Program Assessment, Copper Alloys Within the River Water Environment: Loss of Material due to Selective Leaching, Galvanic Corrosion, Crevice Corrosion, Pitting, MIC, Erosion Corrosion, and Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, Structural Monitoring Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Chemical additions conducted in accordance with PSW and RHRSW Chemistry Control serve to inhibit growth of microorganisms. Inspections of the intake pits conducted in accordance with the PSW and RHRSW Inspection Program and Structural Monitoring Program serve to minimize silt and debris intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for periodic inspections of copper alloys.
5. Monitoring and trending is included for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for trending of data related to loss of material in copper alloys.
6. Acceptance criteria are included	The PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to loss of material within copper alloys.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management programs, including past corrective actions resulting in program enhancements or additional programs are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-6 Aging Management Program Assessment, Copper and Alloys Within the River Water Environment: Flow Blockage Due to Fouling

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Structural Monitoring Program, PSW and RHRSW Inspection Program, and PSW and RHRSW Chemistry Control govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	The PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup and silt dispersant to minimize buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. The PSW and RHRSW Inspection Program examines inscope components for evidence of flow blockage. These inspections minimize particulate intrusion into service water systems.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5.	Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and Structural Monitoring Program provide for monitoring and trending of inspection data.
6.	Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, the PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.6.4 Aging Management Review for Non-Class 1 Gray Cast Iron Components Within the River Water Environment

This commodity group includes gray cast iron components with an internal environment of river water. The following component types are included within this evaluation:

- Strainers

Systems

P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- Loss of material (C.1.2.4.1) due to crevice corrosion, pitting, general corrosion, microbiologically influenced corrosion (MIC), selective leaching, erosion corrosion, galvanic corrosion, and fouling.
- Cracking (C.1.2.4.2) due to thermal fatigue.
- Flow blockage (C.1.2.4.3) due to fouling.

A complete discussion of aging effect determination is found in section C.1 or by following the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *PSW and RHRSW Chemistry Control* (A.1.4)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material and Flow Blockage

PSW and RHRSW Chemistry Control Program provides for treatment with sodium hypochlorite and sodium bromide. Both sodium hypochlorite and sodium bromide are batch added (shock treatment) to the PSW Systems as required. These additions are intended to minimize MIC and macroorganism intrusion within service water systems.

The *PSW and RHRSW Inspection Program* addresses loss of material and flow blockage and implements Plant Hatch's commitment with regard to Generic Letter 89-13. This program outlines the steps necessary to perform systematic and periodic inspection of plant service water and residual heat removal system piping to assure that the necessary quality, operability, safety, and safety limits of the open cycle service water systems are maintained. The following two major tasks are covered by the inspection:

- Inspection of piping for wall degradation
- Inspection of piping for flow blockage

The *Structural Monitoring Program* provides for inspections of the underwater/wetted surfaces of the suction pit for the PSW pumps (including the standby diesel generator service water pump) and the RHRSW pumps located in the intake structure. Additionally, this inspection provides for removal of excessive silt at the intake structure, thereby minimizing silt intrusion into service water systems.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that approximately 155 deficiencies had been written on the P41 system. These deficiencies were screened to determine which ones might be potentially age related. No age related failures were found for the in-scope components covered by this AMR.

It is generally observed that while chemical treatment helps prevent some new problems, the rate of chemical addition is limited by factors other than those the chemicals are intended to combat. Due to the aggressive nature of the river water, chemical treatment of the PSW and RHRSW systems has been increased over the years to the extent allowable. Because these are open cycle systems, and the chemically treated water finds its way back to the river, NPDES restrictions on discharge actually limit the amount of chemicals that can be added.

The results of a review of the Nuclear Plant Reliability Data System (NPRDS) indicate that there have been many plant service water system failures. What is significant about the NPRDS search is the obvious decreasing trend in raw water system failures since about 1991. It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems.

NRC Inspection Report 95-06 addressed follow up items associated with the Service Water System Operational Performance Inspection (i.e., implementation of Generic Letter 89-13). The report concluded that the licensee:

- implemented effective measures in upgrading the service water biological monitoring program,
- enhanced the overall effectiveness of the service water pipe degradation RT program, and
- implemented PSW pump column examinations that would provide adequate assurance that the pumps would not experience significant degradation before corrective actions could be implemented.

Table C.2.2.6-7 Aging Management Program Assessment, Gray Cast Iron Components Within the River Water Environment Loss of Material Due to Crevice, Pitting, General and Galvanic Corrosion, Selective leaching, MIC, Erosion Corrosion and Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program providesfor monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.6-8 Aging Management Program Assessment, Gray Cast Iron Components Within the River Water Environment Flow Blockage due to Fouling

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	PSW and RHRSW Chemistry Control, PSW and RHRSW Inspection Program, and Structural Monitoring Program, govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	PSW and RHRSW Chemistry Control provides for injection of biocides to reduce organic slime buildup and silt dispersant to minimize buildup on component surfaces. The Structural Monitoring Program provides for inspection of the intake pits. These inspections minimize particulate intrusion into service water systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The PSW and RHRSW Inspection Program provides for timely inspections of components within this plant commodity group.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program and the Structural Monitoring Program provide for monitoring and trending of inspection data.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program provide acceptance criteria related to flow blockage in service water systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, the PSW and RHRSW Inspection Program, PSW and RHRSW Chemistry Control, and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.7 Non-Class 1 Components Fuel Oil Environment Description

Components within section C.2.2.7 are subject to an environment of fuel oil under normal conditions. The fuel oil environment is described in section C.1.2.5.

C.2.2.7.1 Aging Management Review for Non-Class 1 Carbon Steel Components Within the Fuel Oil Environment

This commodity group includes carbon steel exposed to an internal environment of fuel oil. The following component types are included within this evaluation:

- Large and small bore piping
- Valve bodies
- EDG transfer pump
- EDG day tanks
- EDG storage tanks
- EDG transfer pump discharge head

Systems

Y52 – Fuel Oil (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.5.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC.
- *Cracking* (C.1.2.5.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Fuel oil is also tested for proper viscosity and specific gravity, thereby detecting any significant degradation of the fuel oil within the storage tank. Acceptance criteria for fuels oil quality is established by Applicable ASTM standards (see Appendix A.1.3).

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Deficiencies related to the diesel fuel oil supply system were limited to five instances of unacceptable sediment and water levels within the EDG Storage Tanks. Acceptable levels were regained promptly via the *Corrective Actions Program*.

One deficiency related to diesel fuel oil testing was noted. The back up sample results for total particulate did not agree with the primary sample. Chemistry procedures were revised to prevent recurrence.

The Nuclear Plant Reliability Data System (NPRDS) was used to chronicle information on plant operating experiences. The results of the NPRDS search demonstrate the extremely low incidence of failure of components exposed to fuel oil. Further, the search did not identify any incidents of corrosion in these systems.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. *Diesel Fuel Oil Testing* provides management of this concern at Plant Hatch as described above.

Table C.2.2.7-1 Aging Management Program Assessment, Carbon Steel Components Within the Fuel Oil Environment: Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of EDG Fuel Oil Supply System components.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
6. Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to the loss of material within carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Diesel Fuel Oil Testing provides for analyses of significant events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.7.2 Aging Management Review for Non-Class 1 Stainless Steel Components Within the Fuel Oil Environment

This commodity group includes stainless steel components exposed to an internal environment of fuel oil. The following component types are included within this evaluation:

- Piping
- Flexible hose
- Strainer baskets
- Valve bodies

Systems

Y52 – Fuel Oil (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.5.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.2.5.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Galvanic corrosion, Pitting, Crevice Corrosion, and MIC

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Fuel oil is also tested for proper viscosity and specific gravity, thereby detecting any significant degradation of the fuel oil within the storage tank. Acceptance criteria for fuels oil quality is established by applicable ASTM standards (see Appendix A.1.3).

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related.

One deficiency related to diesel fuel oil testing was noted. The back up sample results for total particulate did not agree with the primary sample. Chemistry procedures were revised to prevent recurrence.

The Nuclear Plant Reliability Data System (NPRDS) was used to chronicle information on plant operating experiences. The results of the NPRDS search demonstrate the extremely low incidence of failure of components exposed to fuel oil. Further, the search did not identify any incidents of corrosion in these systems.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. Diesel Fuel Oil Testing provides management of this concern at Plant Hatch as described above.

Table C.2.2.7-2 Aging Management Program Assessment, Stainless Steel Components Within the Fuel Oil Environment: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing provides aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of EDG Fuel Oil Supply System components.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
5.	Monitoring and trending for timely corrective actions.	The testing of diesel fuel oil is sufficient such that this attribute of aging management is not required.
6.	Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to the loss of material within stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	Diesel Fuel Oil Testing provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assume that corrective actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.8 Non-Class 1 Components Dry Compressed Gas Environment Description

Components evaluated within this section have an internal environment of dried gases. See section C.1.2.6 for a description of the dried gas environment.

C.2.2.8.1 Aging Management Review for Non-Class 1 Carbon Steel Components in the Dry Compressed Gas Environment

This commodity group includes carbon steel components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Accumulator
- Piping
- Flanges
- Filter housings
- Valve bodies
- Regulator

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None Required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.8.2 Aging Management Review for Non-Class 1 Stainless Steel Components in the Dry Compressed Gas Environment

This commodity group includes stainless steel components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Air Receiver
- Piping
- Flexible hoses
- Rupture discs
- Valve bodies
- Vaporizers
- Pressure buildup coils
- Gas accumulators
- Nitrogen storage tank
- Filter housings

These components are constructed from stainless steel.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.8.3 Aging Management Review for Non-Class 1 Copper Alloy Components in the Dry Compressed Gas Environment

This commodity group includes copper alloy components exposed to an internal environment of dried gas. Component types included in this commodity group include:

- Tubing
- Valve bodies

These components are constructed from copper alloys: copper, brass, and bronze.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

None required.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

Operating experience related to cracking of these components due to thermal fatigue is incorporated into the design assumptions of the ASME codes to which the components were designed. The operating experience for Plant hatch does not indicate a failure due to this mechanism.

C.2.2.9 Humid and Wetted Gases Environment Evaluation

The gases internal to these components are humid or wet, containing sufficient entrained moisture to enable pooling of liquid at low or especially cool locations. The humid gas environment is described in <u>section C.1.2.6</u>.

C.2.2.9.1 Aging Management Review for Non-Class 1 Carbon Steel and Cast Iron Components in the Humid or Wetted Gases Environment

This commodity group includes carbon steel and cast iron components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping and ductwork
- Flexible Connectors
- Filter housings
- Valve bodies
- Flanges
- Diesel fuel oil storage tank man-way shell
- HPCI pump turbine pressure boundary components
- RCIC pump turbine pressure boundary components
- Louvers
- Thermowells
- Nitrogen tank jacket
- Strainer
- Steam trap

Systems

- <u>B21 – Nuclear Boiler</u> (2.3.1.2)
- <u>C11 – Control Rod Drive</u> (2.3.4.1)
- <u>E11 – Residual Heat Removal</u> (2.3.3.2)
- <u>E41 – High Pressure Coolant Injection</u> (2.3.3.4)
- <u>E51 – Reactor Core Isolation Cooling</u> (2.3.3.5)
- <u>R43 – Emergency Diesel Generator</u> (2.3.4.12)
- <u>T23 – Primary Containment</u> (2.4.3)
- <u>T46 – Standby Gas Treatment</u> (2.3.3.6)
- <u>T48 – Primary Containment Purge and Inerting</u> (2.3.3.7)
- <u>T49 – Post-LOCA Hydrogen Recombiners</u> (2.3.3.8)
- <u>X41 – Outside Structures HVAC</u> (2.3.4.17)

- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, selective leaching, pitting, crevice corrosion, galvanic corrosion, and microbiologically influenced corrosion (MIC)
- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to general Surface, Pitting, Crevice, Galvanic, and Microbiologically Influenced Corrosion

Corrosion mechanisms will be detected for these components through a *Gas Systems Component Inspections*. This activity will involve appropriate inspections of a representative sample of the most likely component locations.

The *Passive Component Inspection Activities* provides for inspections, similar to VT-1, of component surfaces anytime an applicable component is opened for periodic maintenance or repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-1 Aging Management Program Assessment, Carbon Steel and Cast Iron Components Containing Humid or Wetted Gases: Loss of Material due to Pitting, Crevice, Galvanic, and Microbiologically Influenced Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6. Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in carbon steels.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Passive Component Inspection Activities, and Gas Systems Component Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.2 Aging Management Review for Non-Class 1 Stainless Steel Components Containing Humid or Wetted Gases

This commodity group includes stainless steel components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping
- Valve bodies
- Strainers
- Restricting orifices
- Steam traps
- Flexible connectors
- Rupture discs
- Thermowells
- Accumulators
- Radiation elements

These components are constructed from stainless steel.

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P33 – Post-Accident Sampling (2.3.4.6)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T23 – Primary Containment (2.4.3)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- T48 – Primary Containment Purge and Inerting System (2.3.3.7)
- T49 – Post-LOCA Hydrogen Recombiners (2.3.3.8)
- X41 – Outside Structures HVAC (2.3.4.17)
- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- Loss of Material (C.1.2.6.1) due to pitting, crevice corrosion, and microbiologically influenced corrosion (MIC).
- Cracking (C.1.2.6.2) due to thermal fatigue, stress corrosion cracking (SCC) and intergranular attack (IGA).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Pitting, Crevice Corrosion, and Microbiologically Influenced Corrosion

Corrosion mechanisms will be detected for these components through a one-time *Gas Systems Component Inspection*. This activity will involve inspections of a representative sample of the most likely component locations subject to humid or wetted gases.

The *Passive Component Inspection Activities* provides for periodic visual examinations, similar to VT-1, of passive component interior surfaces subject to wetted gases. This program will identify and find any significant aging effects occurring within components in this plant commodity group.

Management of Cracking due to Stress Corrosion Cracking and Intergranular Attack

Interior cracking mechanisms will be detected for these components through the *Passive Components Inspection Activities* and the one-time *Gas Systems Component Inspections*. These activities will involve appropriate inspections of a representative sample of the component locations where pooling of liquid is most likely.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-2 Aging Management Program Assessment, Stainless Steel Components Containing Humid or Wetted Gases: Loss of Material due to Pitting, Crevice Corrosion, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5.	Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6.	Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.9-3 Aging Management Program Assessment, Stainless Steel Components Containing Humid or Wetted Gases: Crack Initiation and Growth Due to IGA and SCC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Gas Systems Component Inspections and Passive Component Inspection Activities govern aging management for the components within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The inspections used in Gas Systems Component Inspections and Passive Component Inspection Activities are adequate to identify cracking in gas system stainless steel prior to significant degradation.
5.	Monitoring and trending for timely corrective actions.	The Gas Systems Component Inspections Activities and Passive Component Inspection Activities provide for monitoring and trending of degradation in gas system components.
6.	Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for SCC and IGA in stainless steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.3 Aging Management Review for Non-Class 1 Copper Alloy Components Containing Humid or Wetted Gases

This commodity group includes copper alloy components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping and tubing
- Valve bodies

These components are constructed from copper or brass.

Systems

- C11 – Control Rod Drive (2.3.4.1)
- R43 – Emergency Diesel Generator (2.3.4.12)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- X41 – Outside Structures HVAC (2.3.4.17)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- Loss of Material (C.1.2.6.1) due to selective leaching, pitting, crevice corrosion, MIC, and galvanic corrosion.
- Cracking (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material due to Selective Leaching, Pitting, Crevice Corrosion, MIC, and Galvanic Corrosion

Evidence of interior corrosion mechanisms will be detected for these components through a one-time *Gas Systems Component Inspections*. This activity will involve inspections of a representative sample of the most likely component locations.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the C11, R43, T41, T46, X41, and Z41 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-4 Aging Management Program Assessment, Copper Alloy Components Containing Humid or Wetted Gases: Loss of Material due to Selective leaching or due to Pitting, Crevice Corrosion, and MIC

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5. Monitoring and trending for timely corrective actions.	Since corrosion in these systems is expected to be minimal, monitoring and trending are not necessary. The one-time inspections will confirm this position.
6. Acceptance criteria are included.	The Gas Systems Component Inspections include acceptance criteria for corrosion in copper alloys.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Gas Systems Component Inspections ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.9.4 Aging Management Review for Non-Class 1 Galvanized Carbon Steel and Aluminum Components Containing Humid or Wetted Gases

This commodity group includes galvanized carbon steel and aluminum components exposed to an internal environment of humid or wet gas. Component types included in this commodity group include:

- Piping
- Ductwork
- Filter housing
- Duct silencer
- Duct heater

Systems

- R43 – Emergency Diesel Generator (2.3.4.12)
- T41 – Reactor Building HVAC (2.3.4.15)
- T46 – Standby Gas Treatment (2.3.3.6)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC. For this section, this aging effect applies to the R43 piping for the emergency diesel generator exhausts, the Z41 aluminum duct heater, and Z41 ductwork mounted outside the control building.
- *Cracking* (C.1.2.6.2) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Thermal Fatigue

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Management of Loss of Material due to General Surface and Galvanic Corrosion

Evidence of corrosion mechanisms will be detected for these components through *Gas Systems Component Inspections*. This activity will involve inspections of a representative sample of the most likely component locations subject to humid or wetted gases.

The *Passive Component Inspection Activities* provides for inspections, similar to VT-1, of the emergency diesel generator exhausts and ductwork on the control building roof anytime an applicable component is opened for periodic maintenance or repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Review of Operating Experience

A review of condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the R43, T41, T46, and Z41 systems. These deficiencies were screened to determine which ones might be potentially age-related. No age-related failures due to loss of material or cracking of in-scope components, applicable to this plant commodity group, were found.

Table C.2.2.9-5 Aging Management Program Assessment, Galvanized Carbon Steel and Aluminum Components Containing Humid or Wetted Gases: Loss of Material due to General Surface, Galvanic Corrosion, Crevice Corrosion, Pitting, and MIC

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Passive Component Inspection Activities and Gas Systems Component Inspections govern aging management for the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and Gas Systems Component Inspections provide for periodic inspections of gas system components. Since corrosion in these systems is expected to be minimal, these inspections are adequate to detect loss of material in a timely manner.
5.	Monitoring and trending for timely corrective actions.	The Passive Component Inspection Activities provide for compilation of data and identification of trends concerning significant loss of material in gas system components.
6.	Acceptance criteria are included.	The Gas Systems Component Inspections and Passive Component Inspection Activities include acceptance criteria for corrosion in galvanized carbon steels.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.10 Non-Class 1 Pressure Boundary Bolting Evaluation

Pressure Boundary Bolting within section C.2.2.10 are subject to inside and outside environments at Plant Hatch. Only bolting pertaining to piping connections are evaluated by this section. Bolting supplied by vendors as part of valves, pumps, strainers, etc. are not subject to an aging management review. Section C.1.2.7 of the LRA includes an analysis of aging effect determinations for bolting materials at Plant Hatch.

C.2.2.10.1 Aging Management Review for Non-Class 1 Bolting Materials

This commodity group includes carbon steel pressure boundary bolting. This bolting is fabricated from carbon and low alloy carbon steel fabricated to the requirements of ASTM A-307 (Grade B), ASME SA 194 (Grade 2H), and ASME SA 193 (Grade B7).

Systems

- B21 – Nuclear Boiler (2.3.1.2)
- C11 – Control Rod Drive (2.3.4.1)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- N61 – Main Condenser (2.3.5.2)
- P41 – Plant Service Water (2.3.4.7)
- P42 – Reactor Building Closed Cooling Water (2.3.4.8)
- P52 – Instrument Air (2.3.4.9)
- P64 – Primary Containment Chill Water (2.3.4.10)
- P70 – Drywell Pneumatic (2.3.4.11)
- T23 – Primary Containment (2.4.3)
- T41 – Reactor Building HVAC (2.3.4.15)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- T49 – Post LOCA Hydrogen Removal (2.3.3.8)
- W33 – Traveling Water Screens, Trash Racks (2.3.4.16)
- X41 – Outside Structures HVAC (2.3.4.17)
- X43 – Fire Protection (2.3.4.18)
- Y52 – Fuel Oil (2.3.4.19)
- Z41 – Control Room HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.7.1) due to general corrosion of carbon steel fasteners in the inside environment and general corrosion, pitting, crevice corrosion, and MIC in the outside environment.
- *Loss of Preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *Torque Activities* (A.1.11)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-loosening

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of guidelines for preload within non-Class 1 fasteners. These torque activities meet the intent of EPRI guidelines for degradation and failure of bolting in nuclear power plants that were generally endorsed by the NRC in NUREG 1339, "Resolution of GSI 29."

Management of Loss of Material due to General Corrosion

Since some fasteners may be susceptible to general corrosion, the *Protective Coatings Program* provides for periodic inspection of component external surfaces, including fasteners. This program will also provide for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces).

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Numerous instances of bolted joint failure due to loss of preload were noted during regular system walk-downs and *ISI Program* mandated pressure testing. Many instances of degradation due to general corrosion were also noted during regular system surveillance activities. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.2.10-1 Aging Management Program Assessment for Non-Class 1 Carbon Steel Bolting Materials Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Torque Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.10-2 Table Aging Management Program Assessment for Non-Class 1 Carbon Steel Bolting Materials Loss of Material due to General Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program is designed to mitigate age-related degradation by specifying recommended grades of protective coatings, and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program provides for periodic inspection of components within this commodity group to ensure no significant degradation due to general corrosion has occurred.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included.	The Protective Coatings Program provides acceptance criteria for applied coatings systems.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.10.2 Aging Management Review for Non-Class 1 Stainless Steel Bolting Materials

This commodity group includes stainless steel pressure boundary bolting.

Systems

- C41 – Standby Liquid Control (2.3.3.1)
- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P11 – Condensate Transfer and Storage (2.3.4.5)
- P52 – Instrument Air (2.3.4.9)
- P70 – Drywell Pneumatic (2.3.4.11)
- T48 – Primary Containment Purge and Inerting (2.3.3.7)
- X41 – Outside Structures HVAC (2.3.4.17)

Aging Effects Requiring Management

- *Loss of preload* (C.1.2.7.2) due to embedment, gasket creep, thermal effects, and self-loosening.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *Torque Activities* (A.1.11)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Management of Loss of Preload

Torque Activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. These torque activities meet the intent of EPRI guidelines for degradation of bolting in nuclear power plants.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Numerous instances of bolted joint failure due to loss of preload were noted during regular system walk-downs and *ISI Program* mandated pressure testing. Many instances of degradation due to general corrosion were also noted during regular system surveillance activities. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.2.10-3 Aging Management Program Assessment for Non-Class 1 Stainless Steel Bolting Materials Loss of Preload due to Embedment, Gasket Creep, Thermal Effects, and Self-Loosening

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Torque Activities governs aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Torque Activities are designed to mitigate age-related degradation by controlling initial preload within bolted connections.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	The Torque Activities sufficiently mitigate loss of preload such that this attribute of aging management is not required.
6. Acceptance criteria are included.	The Torque Activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Torque Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.2.11 Non-Class 1 Heat Exchanger Evaluation

The residual heat removal system heat exchangers are fabricated from several different materials and are exposed to multiple fluid environments. Therefore, these heat exchangers are evaluated in a separate commodity group.

C.2.2.11.1 Aging Management Review for Residual Heat Removal Heat Exchangers

The residual heat removal system heat exchangers provide a method for removing heat from the reactor pressure vessel or suppression pool. These heat exchangers include the following components:

- Tubes – stainless steel
- Shell, Shell Nozzles, and Shell Internals – carbon steel
- Channel Assembly (including channel head, water box, and partition plate) – carbon steel
- Tube Sheet – carbon steel with stainless steel cladding on raw water side surfaces and carbon steel on torus water side
- Impingement Plate – stainless steel

Systems

- E11 – Residual Heat Removal (2.3.3.3)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2 and C.1.2.4.2) due to stress corrosion cracking and intergranular attack of stainless steel components and vibration induced fatigue.
- *Loss of Material* (C.1.2.1.1 and C.1.2.4.1) due to general corrosion, galvanic corrosion crevice corrosion, pitting, MIC, and fouling.
- *Loss of Heat Exchanger Performance* (C.1.2.4.4) due to corrosion product buildup, silting, and macroorganism intrusion.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Programs To Manage Aging Effects:

- *RHR Heat Exchanger Augmented Inspection and Testing Program* (A.3.6)
- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Suppression Pool Chemistry Control* (A.1.7)
- *Plant Service Water and RHR Service Water Chemistry Control* (A.1.4)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Cracking due to Stress Corrosion Cracking, Intergranular Attack, and Vibration Induced Cracking

The RHR Heat Exchanger Augmented Inspection and Testing Program provides for the following combination of inspections and tests as applicable to manage Cracking due to Stress Corrosion, Intergranular Attack, and Vibration Induced Fatigue.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the Plant Service Water and RHR Service Water Inspection Program.
- Eddy Current tests are performed at scheduled intervals and whenever leaks are suspected in tubes and/or tube sheets.
- Leak Testing is performed to detect leaks in tubes and/or tube sheet whenever leaks are suspected.

The Inservice Inspection Program provides volumetric and surface examinations of the RHR Heat Exchanger shell circumferential welds, shell head circumferential welds, and nozzle to shell welds in accordance with ASME Section XI, 1989, Table IWC 2500-1 code.

The program is implemented to detect any flaws and cracking in these welds and in ½ inch of the base material from the toe of the weld. Therefore, by performing this program, cracking of the pressure retaining weld and half (1/2) inch of the base material is managed.

The Suppression Pool Chemistry Control serves to minimize SCC and IGA for shell side stainless steel surfaces. This program provides for low limits on halogen content and conductivity, thereby providing control of SCC and IGA for shell side surfaces; i.e., impingement plate and outer surface of the tubes.

Management of Loss of Material

Carbon steel components may experience loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion, erosion corrosion, silting and corrosion product buildup, debris intrusion, and MIC.

Stainless steel components and cladding may experience loss of material due to crevice corrosion, pitting, silting and corrosion product buildup, debris intrusion, and MIC.

The Suppression Pool Chemistry Control serves to minimize loss of material for shell side surfaces. This program provides for low limits on halogen content and conductivity, thereby providing mitigation of corrosion on these surfaces.

The Plant Service Water and RHR Service Water Chemistry Control provides for addition of biocides in order to lower the potential for MIC, and MAC within raw water system components. These additions serve to reduce the potential for significant loss of material due to corrosion within the RHR Heat Exchangers.

The *RHR Heat Exchanger Augmented Inspection and Testing Program* provides for the following combination of inspections and tests as applicable to manage loss of material.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the *Plant Service Water and RHR Service Water Inspection Program*.
- Eddy Current tests are performed at scheduled interval and whenever leaks are suspected in tubes and/or tube sheets.
- Leak Testing is performed to detect leaks in tubes and/or tube sheet whenever leaks are suspected.

The *Inservice Inspection Program* provides for volumetric and surface examinations of the RHR Heat Exchanger shell circumferential welds, shell head circumferential welds and nozzle to shell welds in accordance with ASME Section XI, 1989, Table IWC 2500-1 Code.

The program is implemented to detect any flaws and loss of material in these welds and in ½ inch of the base material from the toe of the weld. Therefore, by performing this program, cracking of the pressure retaining weld and half (1/2) inch of the base material is managed.

The *Structural Monitoring Program*, by preventing build up of foreign material in the intake structure, prevents macroorganisms or silt to be carried to Heat Exchanger Components, thereby preventing formation of crevices that can cause loss of material due to crevice corrosion.

Management of Loss of Heat Exchanger Performance due to Fouling

The *RHR Heat Exchanger Augmented Inspection and Testing Program* provides for the following combination of inspections and tests as applicable to manage loss of thermal performance due to fouling.

- Visual inspections are performed at scheduled intervals of the internal surfaces of the Heat Exchanger Channel and Shell sides. These inspections are performed in accordance with the Plant Service Water and RHR Service Water Inspection Program.
- Eddy Current tests are performed at scheduled interval.

The *Suppression Pool Chemistry Control* provides for low limits on halogen content and conductivity and, thereby controls corrosion product build up in the shell side.

The *Plant Service Water and RHR Service Water Chemistry Control* provides for addition of biocides in order to control microbiological and macrobiological species to avoid fouling.

The Structural Monitoring Program, by preventing build up of foreign material in the intake structure, prevents macroorganisms or silt to be carried to heat exchanger components, and thereby, prevents fouling.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 revealed one significant event for RHR Heat Exchangers. During 1996, a sample taken from a RHRSW drain valve contained the presence of nuclides. A root cause investigation and subsequent helium leak test and eddy current testing performed on the 1E11-B001 RHR heat exchanger identified possible leakage in 9 heat exchanger tubes. Subsequent inspection of the tube bundle revealed that, other than the leaking tubes, the tube bundle was in good condition and suitable for continued service. Dents were noted at the tube to tube support connections and may be indicative of tube vibration. However, no exact cause for the tube leakage was identified. No tube leaks for other RHR heat exchangers occurred during the five-year period under consideration.

Table C.2.2.11-1 Aging Management Program Assessment Cracking due to SCC and IGA of Stainless Steel Components With RHR Heat Exchangers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RHR Heat Exchanger Augmented Inspection and Testing Program, Suppression Pool Chemistry Control, and Inservice Inspection Program govern aging management for the RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The scheduled inspections required by the RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program are sufficient to detect cracking within stainless steel heat exchanger components prior to loss of intended function.
5. Monitoring and trending for timely corrective actions.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program provide for trending of degradation within RHR heat exchangers.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, RHR Heat Exchanger Augmented Inspection and Testing Program, ISI Program provide specific acceptance criteria related to cracking of stainless steel components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-2 Aging Management Program Assessment Cracking Within RHR Heat Exchangers due to Vibration Fatigue

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program govern aging management for the RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Inservice Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program inspections are designed to provide timely detection of degradation of RHR heat exchangers.
5. Monitoring and trending for timely corrective actions.	The ISI Program and RHR Heat Exchanger Augmented Inspection and Testing Program provide for monitoring and trending of RHR heat exchanger conditions. The Corrective Actions Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included.	The ISI Program and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to cracking within RHR heat exchangers.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-3 Aging Management Program Assessment Loss of Material Within RHR Heat Exchangers

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and ISI Program encompass aging management for the RHR heat exchangers.
2.	Preventive actions to mitigate or prevent aging degradation.	The Suppression Pool Chemistry Control and PSW and RHRSW Chemistry Control provides for chemical monitoring and additions designed to mitigate loss of material within the RHR heat exchangers. The Structural Monitoring Program minimizes loss of material by reducing fouling rates
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, and the Structural Monitoring Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program and ISI Program inspections are designed to provide timely detection of degradation of RHR heat exchangers.
5.	Monitoring and trending for timely corrective actions.	The ISI Program, RHR Heat Exchanger Augmented Inspection and Testing Program, and Structural Monitoring Program provide for monitoring and trending of RHR heat exchanger condition.
6.	Acceptance criteria are included.	The Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, ISI Program, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to loss of material within RHR heat exchangers.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, ISI Program, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a process for identifying deficient conditions and ensuring proper corrective action is taken.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.2.11-4 Aging Management Program Assessment Loss of Heat Exchanger Performance Within RHR Heat Exchangers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program govern aging management within RHR heat exchangers.
2. Preventive actions to mitigate or prevent aging degradation.	Suppression Pool Chemistry Control and PSW and RHRSW Chemistry Control provides for chemical monitoring and additions designed to minimize fouling within the RHR heat exchangers. The Structural Monitoring Program minimizes particulate intrusion into the heat exchanger components, and thereby reduces fouling rates.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the RHR Heat Exchanger Augmented Inspection and Testing Program provides for visual inspections or eddy current testing, and the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The RHR Heat Exchanger Augmented Inspection and Testing Program is designed to provide timely detection of degradation of RHR heat exchangers thermal performance.
5. Monitoring and trending for timely corrective actions.	The RHR Heat Exchanger Augmented Inspection and Testing Program and the Structural Monitoring Program provide for monitoring and trending of data concerning RHR heat exchanger condition.
6. Acceptance criteria are included.	The Suppression Pool Chemistry Control, PSW and RHRSW Chemistry Control, Structural Monitoring Program, and RHR Heat Exchanger Augmented Inspection and Testing Program provide detailed acceptance criteria related to loss of performance within RHR heat exchangers.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, RHR Heat Exchanger Augmented Inspection and Testing Program, PSW and RHRSW Chemistry Control, Suppression Pool Chemistry Control, and Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3 AGING MANAGEMENT REVIEWS FOR FIRE PROTECTION SYSTEM COMPONENTS

The demonstration of aging management for fire protection system components is presented based on the component function within the fire protection system.

- Water Based Fire Suppression Systems
- Fire Protection Diesel Fuel Oil Supply System
- Compressed Gas Based Fire Suppression Systems
- Fire Barriers for Preventing Fire Propagation

Aging management for fire protection systems is accomplished by *Fire Protection Activities*, the *Protective Coatings Program*, and *Diesel Fuel Oil Testing* as described in Appendix A of the LRA.

C.2.3.1 Evaluation of Water Based Fire Suppression Systems

Water based fire suppression systems contain both air (for those dry pipe system components downstream of the multimatic isolation valve) and well water drawn from deep draft wells on site and passed through mechanical filters. See the well water description for more information. The system consists of many general component types.

Components are fabricated from stainless steels, carbon steels, galvanized steels, ceramics copper alloys, cast irons, aluminum alloys, and lead alloys.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.4.1 and C.1.2.6.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), selective leaching, and fouling.
- *Cracking* (C.1.2.4.2 and C.1.2.6.2) due to SCC, IGA, and thermal fatigue.
- *Flow Blockage* (C.1.2.4.3) due to fouling.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management

Fire Protection Activities provide for aging management of water based fire suppression system components. Fire Protection Activities require flushing of the header loop on a regular basis to remove corrosion product buildup and ensure adequate flow through the system. The diesel fire pumps are visually inspected and operationally tested on a regular schedule. The fire water storage tank internal surfaces are periodically inspected. Sprinkler nozzles are visually inspected and air flow tested on a regular schedule. Valves are cycled to verify functionality. These tests, inspections, and routine maintenance ensure that water based fire suppression system components are able to maintain their intended functions throughout the period of extended operation.

The *Protective Coatings Program* provides for prevention of corrosion within the fire water storage tank by maintaining sufficient coating on the internal surfaces of the storage tank. Results of Fire Protection Activities inspections on the tank are utilized to identify coating reapplication requirements.

Cracking due to thermal fatigue has been analyzed and the analysis is a TLAA. See section 4.2.3 for a discussion of the TLAA.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written on fire protection system components. Deficiencies included leaking piping (mostly within buried sections), deterioration of coatings within the fire water storage tank, and fouling of lines due to corrosion product buildup. All of these deficiencies were identified during testing and inspection required by the Fire Protection Activities or during normal walkdown activities. Due to the design features of the system, including excess capacity and loop design, none of these failures was judged to constitute a loss of intended function.

Table C.2.3.1-1 Aging Management Program Assessment, Aging Effects Requiring Management for Water Based Fire Suppression System Components

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities and Protective Coatings Program govern aging management for water based fire suppression system components.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides for mitigation of corrosion within the fire water storage tank. The Fire Protection Activities prevent or mitigate loss of material by utilizing system flushes to remove undesirable material from the system. Inspection and testing of water based fire suppression systems conducted in accordance with the Fire Protection Activities is sufficient to detect degradation prior to any loss of intended function.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections and performance testing of water based fire suppression system components. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provides for proper corrective actions any time degradation of water based fire suppression system component is detected. The Protective Coatings Program ensures resolution of deficiencies in a timely manner.
6. Acceptance criteria are included.	The Fire Protection Activities and the Protective Coatings Program provide specific acceptance criteria related to degradation of water based fire suppression system components and coatings.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Fire Protection Activities, and the Protective Coatings Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.2 Evaluation of Fire Protection Diesel Fuel Oil Supply System

Fuel oil supply to the fire protection system diesel driven fire pumps includes the fuel oil storage tank, piping, valves, and strainer baskets.

Components are fabricated from stainless steels, carbon steels, copper alloys, and cast irons.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- Loss of material (C.1.2.5.1 and C.1.2.6.1) due to general corrosion, galvanic corrosion, pitting, crevice corrosion, and MIC.
- Cracking (C.1.2.5.2 and C.1.2.6.2) due to thermal fatigue, SCC, and IGA.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Diesel Fuel Oil Testing* (A.1.3)
- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management

Diesel Fuel Oil Testing provides for sampling and analysis of fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to assure that no significant buildup of contaminants exists. If excessive contamination does occur, the program provides for draining and cleaning of the tank as required to reestablish and maintain acceptable contaminant levels. Acceptance criteria for fuels oil quality is established by applicable ASTM standards. See Appendix A.1.3.

Fire Protection Activities provide for visual inspections and performance testing of the fire protection diesel fuel oil supply system. These inspections and tests are conducted on a regular basis and are adequate to detect degradation of system components prior to loss of intended function. Regular performance testing prevents degradation of fuel oil within the supply lines connecting the storage tank and diesel engine.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on fire protection diesel fuel oil system components. These deficiencies related to excessive sedimentation and water within the fire pump diesel fuel oil storage tanks. These deficiencies and subsequent corrective actions were detected and managed by *Diesel Fuel Oil Testing*.

Information Notice 91-46 indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. The *Diesel Fuel Oil Testing* and *Fire Protection Activities* provide management of this concern at Plant Hatch as described above.

Table C.2.3.2-1 Aging Management Program Assessment, Aging Effects Requiring Management for Fire Protection Diesel Fuel Oil Supply System Components

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Diesel Fuel Oil Testing and Fire Protection Activities govern aging management for the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Diesel Fuel Oil Testing is designed to mitigate age-related degradation of fire protection diesel fuel oil supply system components by detecting and preventing the introduction of contaminated oil into plant systems.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Fire Protection Activities provides for visual inspections and performance testing of fire protection diesel fuel oil system components.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide a means for evaluating the effectiveness of current diesel fuel oil testing standards in preventing aging degradation within fire protection diesel fuel oil supply system components during the period of extended operation.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for compilation of data concerning aging of fire protection diesel fuel oil system components.
6. Acceptance criteria are included.	Diesel Fuel Oil Testing provides detailed acceptance criteria related to aging of fire protection diesel fuel oil system components. The Fire Protection Activities provides acceptance criteria for visual inspections and/or performance testing of fire protection diesel fuel oil system components.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Diesel Fuel Oil Testing, and Fire Protection Activities ensures corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.3 Evaluation of Compressed Gas Based Fire Suppression Systems

Compressed gas fire suppression systems consist of CO_2 and halon-based systems. High-pressure bottles and refrigerated liquid CO_2 storage tanks are used as compressed gas supplies. Components upstream of the pressure isolation valve are exposed to dry compressed gases or refrigerated liquefied gases under normal conditions. Components downstream of the isolation valve are exposed to humid air under normal conditions. Components include valves, piping, nozzles, and storage tanks. See C.1.2.6 for a description of gas environments.

Components are fabricated from carbon steels, galvanized steels, copper alloys, aluminum alloys, cast irons and insulating materials such as polystyrene foam, urethane foam, and isocyanurate.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.6.1) due to general corrosion, galvanic corrosion, selective leaching, pitting, crevice corrosion, wear, and intrusion of water born agents.
- *Cracking* (C.1.2.6.2) due to IGA, SCC, and thermal fatigue.
- *Change in Material Properties* (C.1.2.11.3) due to compaction and settling, intrusion of water borne agents, thermal effects, and material separation within insulating materials.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Aging Effects Requiring Management for Metallic and Insulation Components

Fire Protection Activities provide for visual inspections and performance testing of compressed gas fire suppression systems. These inspections and tests are conducted on a regular basis and are adequate to detect degradation of compressed gas fire suppression system components prior to loss of intended function.

Fire Protection Activities also manage aging of insulation products by providing regular, focused inspections of insulation installed on the CO_2 storage tanks. These inspections are adequate to detect degradation of tank insulation prior to a loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on compressed gas systems. All of these deficiencies related to exterior corrosion of piping components in areas of coating degradation. External components aging effects and associated aging management programs are addressed in section C.2.4 of the LRA. No deficiencies related to aging of component internals or insulation were identified.

Table C.2.3.3-1 Aging Management Program Assessment, Aging Effects Requiring Management for Compressed Gas Fire Suppression System Components

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management of compressed gas fire suppression system components on a periodic basis.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degredation.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Fire Protection Activities provides for specific inspections and performance testing of compressed gas fire suppression systems.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provides for timely inspections and performance testing of compressed gas fire suppression system components.
5.	Monitoring and trending for timely corrective actions.	The Fire Protection Activities provides for proper corrective actions any time degradation of a compressed gas fire suppression system component is detected. The Corrective Actions Program ensures resolution of deficiencies in a timely manner.
6.	Acceptance criteria are included.	The Fire Protection Activities provides specific acceptance criteria related to degradation of compressed gas fire suppression system components.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and the Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program provides a means to assure that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4 Evaluation of Fire Barriers for Preventing Fire Propagation

C.2.3.4.1 Fire Penetration Seals

Fire penetration seals are assemblies fabricated from combinations of the following materials:

- Carbon steel
- Concrete
- Silicon rubber foam
- Fiber material (fiberglass and rockwool)
- Ceramics (ceraboard)

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.11.1 and C.1.4.1) due to general corrosion, crevice corrosion, and pitting of carbon steel sleeves and wear or fretting of fiber and ceramic materials.
- *Change in Material Properties* (C.1.2.11.3 and C.1.4.2) within concrete due to elevated temperature degradation, compaction and settling, and deformation and material separation of fiber, ceramic, and foam materials.
- *Cracking* (C.1.2.11.2 and C.1.4.1) of carbon steel sleeves due to fatigue, and of fiber, ceramic, and foam materials due to thermal degradation.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Degradation of Fire Penetration Seals

Fire Protection Activities provide for visual inspections of fire penetration seals. These inspections occur at regular intervals and are adequate to detect degradation of fire penetration seals prior to any loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on fire penetration seals. These deficiencies were screened to determine which ones might be potentially age-related. All of the failures involved only minor degradation of the seal. None of these failures was determined to be significant since no loss of intended function occurred.

Table C.2.3.4-1 Aging Management Program Assessment, Aging Effects Requiring Management for Fire Penetration Seals

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management for fire penetration seals.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections of fire penetration seals.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for proper corrective actions any time degradation of a fire penetration seal is detected.
6. Acceptance criteria are included.	The Fire Protection Activities provide specific acceptance criteria related to degradation of fire penetration seals.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4.2 Cable Tray Fire Barriers

Cable tray fire barriers consist of Kaowool insulation (or an equivalent material) wrapped around safe shutdown required cable trays and the galvanized steel straps and fasteners used to affix the insulation to the trays.

Systems

- X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.11.1) due to general corrosion and galvanic corrosion of galvanized steel fastening components and wear or fretting of insulation.
- *Change in Material Properties* (C.1.2.11.3) of insulation materials due to compaction and settling and thermal degradation.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Degradation of Fire Protection Insulation

Fire Protection Activities provide for visual inspections of fire protection insulation materials installed on cable trays. These inspections occur at regular intervals and are adequate to detect degradation of fire penetration seals prior to any loss of intended function.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that no deficiencies were determined to be age-related.

Generic Letter 92-08, "Thermo-Lag Fire Barriers," was issued by the NRC in December 1992 when it was discovered that Thermo-Lag 330-1 fire barrier material did not meet NRC requirements as evidenced by failure of the material to pass fire exposure tests. In response, Southern Nuclear indicated that Thermo-Lag would not be relied upon as a fire barrier material at Plant Hatch.

Table C.2.3.4-2 Aging Management Program Assessment, Aging Effects Requiring Management for Cable Tray Fire Barriers

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	The Fire Protection Activities govern aging management for cable tray fire barrier materials on a periodic basis.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular structure, component or commodity intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities provide for timely inspections of cable tray fire barrier materials.
5. Monitoring and trending for timely corrective actions.	The Fire Protection Activities provide for proper corrective actions any time degradation of a fire penetration seal is detected.
6. Acceptance criteria are included.	The Fire Protection Activities provide specific acceptance criteria related to degradation of cable tray fire barrier materials.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Fire Protection Activities ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.3.4.3 Fire Doors

Fire doors are metal assemblies fabricated with nonmetallic insulating internals:

Systems:

X43 – Fire Protection (2.3.4.18)

Aging Effects Requiring Management:

- *Loss of Material* (C.1.2.8.1 and C.1.2.9.1) due to general corrosion of carbon steel structural materials and associated bolts and fasteners.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Applicable Aging Management Programs:

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fire Protection Activities* (A.2.1)

Management of Loss of Material due to General Corrosion

Fire Protection Activities provide for visual inspections of fire doors. These inspections occur at regular intervals and are adequate to detect corrosion of fire doors prior to any loss of fire barrier function.

Review of Operating Experience:

A review of the condition reporting database mentioned in section 3.0 showed that approximately 1100 deficiencies had been written on the in-scope fire doors. These deficiencies were screened to determine which ones might be potentially age related. These deficiencies primarily involved problems with active components (e.g., door knobs, closers, etc.) due to mechanical use. No deficiencies resulted from identified age related degradation of the fire doors.

Table C.2.3.4-3 Aging Management Program Assessment for Fire Doors: Loss of Material due to General Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity (SCC) for the identified aging effect.	The <u>Fire Protection Activities</u> include fire rated doors in the Category I buildings, and the Category II Turbine building, Radwaste building west wall, and Fire Pump House.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular SCC function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Fire Protection Activities require regular inspection and surveillance of fire doors to detect possible degradation and prevent a loss of fire barrier function.
5. Monitoring and trending is included for timely corrective actions.	The Fire Protection Activities provide for routine fire door surveillance to detect degradation and assure timely corrective or mitigative actions to prevent a loss of fire rating.
6. Acceptance criteria are included.	The Fire Protection Activities include acceptance criteria for fire doors against which corrective action is evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The <u>Corrective Actions Program</u> and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

C.2.4 AGING MANAGEMENT REVIEWS FOR MECHANICAL COMPONENT EXTERNAL SURFACES

Component external surfaces may be exposed to three general environment types:

- Inside (C.1.2.8)
- Outside (C.1.2.9)
- Buried or Embedded (C.1.2.10)

See section C.1 or use the above links for external environment definitions.

C.2.4.1 Aging Management Review for Commodity External Surfaces Exposed to an Inside Environment

This evaluation applies to the external surfaces of all inscope mechanical process components located within a controlled building environment at Plant Hatch (reactor building, turbine building, diesel generator building, control building, and intake structure). Components are fabricated from stainless steel, carbon steel, copper alloys (bronze, brass, pure copper), galvanized steel, and cast iron. This section applies only to the normal inside environment where minimal wetting and wet/dry cycling is expected to occur. See section C.1.2.8 for a discussion of the aging effects that may result for the materials in these environments.

Systems

Many systems within the scope of license renewal have systems, structures, or components located within the inside environment. The aging management review for external aging effects is not system dependent.

Aging Effects Requiring Management

- Loss of material (C.1.2.8) due to general corrosion in areas where the external surface is less than 200 °F.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Fire Protection Activities* (A.2.1)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior Surfaces of In Scope Components

The *Protective Coatings Program* provides a means for preventing or mitigating loss of material that would otherwise result from contact of the base metal with the environment. Additionally, this program provides instructions on surface cleaning and preparation of component surfaces (specific acceptance criteria is provided for each type of cleaning method including hand cleaning, solvent cleaning, and near white blasting), mixing and thinning of paints, paint application, and inspection and testing of coatings (acceptance criteria is based on the paint manufacturer's recommendations for dry film thickness and a visual examination).

The *Fire Protection Activities* provide for regular walkdowns of fire suppression systems, thereby providing a method for identifying and correcting significant degradation of component surfaces or coatings.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors. These deficiencies related to corrosion of carbon steel and low alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting due to packing leakage had occurred. No aging effects were found that had not been previously identified.

Table C.2.4.1-1 Aging Management Program Assessment, External Surfaces of Inside Commodities: Loss of Material due to Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program and Fire Protection Activities govern aging management the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program and Fire Protection Activities provide for periodic inspections designed to detect degradation of component exterior surfaces.
5. Monitoring and trending for timely corrective actions.	The Protective Coatings Program and Fire Protection Activities provide trending of data to ensure proper corrective actions.
6. Acceptance criteria are included.	The Protective Coatings Program and Fire Protection Activities include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Protective Coatings Program, and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.2 Aging Management Review for Commodity External Surfaces exposed to an Outside Environment

This evaluation applies to the external surfaces of all inscope mechanical process components not located within a controlled building environment at Plant Hatch (excluding buried components). Components are fabricated from stainless steel, carbon steel, copper alloys (bronze, brass, pure copper), galvanized steel, aluminum alloy, and cast iron. See section C.1.2.9 for a discussion of the aging effects that may result for the materials in these environments.

Systems

Many systems within the scope of license renewal have systems, structures, or components located in an outside environment. The aging management review for external aging effects is not system dependent.

Aging Effects Requiring Management

- *Loss of material* (C.1.2.9) due to general corrosion, selective leaching, pitting, crevice corrosion, and galvanic corrosion in areas where the external surface is less than 200 °F and the potential for significant wetting or pooling of water exists.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Gas Systems Component Inspections* (A.3.3)
- *Protective Coatings Program* (A.2.3)
- *Fire Protection Activities* (A.2.1)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior Surfaces of In Scope Components

The *Protective Coatings Program* provides a means for preventing or mitigating loss of material that would otherwise result from contact of the base metal with the environment. Additionally, this program provides instructions on surface cleaning and preparation of component surfaces (specific acceptance criteria is provided for each type of cleaning method including hand cleaning, solvent cleaning, and near white blasting), mixing and thinning of paints, paint application, and inspection and testing of coatings (acceptance criteria is based on the paint manufacturer's recommendations for dry film thickness and a visual examination).

The *Fire Protection Activities* provide for regular walkdowns of fire suppression systems, thereby providing a method for identifying and correcting significant degradation of component surfaces or coatings.

The *Passive Component Inspection Activities* will require southern Nuclear to inspect the normally in accessible surfaces of in-scope components such as externally located ductwork (X41, Z41) located on the roof of the reactor building, diesel generator building and intake structure during maintenance activities

The *Gas Systems Component Inspections* one-time inspection will include a representative sample of the surfaces to demonstrate the lack of detrimental aging effects.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors. These deficiencies related to corrosion of carbon steel and low alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting due to packing leakage had occurred. No aging effects were found that had not been previously identified.

Table C.2.4.2-1 Aging Management Program Assessment, External Surfaces of Outside Commodities: Loss of Material due to Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Protective Coatings Program, Gas Systems Component Inspections, Passive Component Inspection Activities, and Fire Protection Activities govern aging management the components included within this plant commodity group.
2.	Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3.	Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Fire Protection Activities provide for visual inspection or performance testing; the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections; the Passive Components Inspection Activities provide for visual or surface inspections; and the Protective Coatings Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program, Passive Component Inspection Activities, Gas Systems Component Inspections, and Fire Protection Activities provide for periodic inspections designed to detect degradation of component exterior surfaces.
5.	Monitoring and trending for timely corrective actions.	The Protective Coatings Program, Passive Component Inspection Activities, and Fire Protection Activities provide trending of data to ensure proper corrective actions.
6.	Acceptance criteria are included.	The Protective Coatings Program, Gas Systems Component Inspection, Passive Component Inspection Activities, and Fire Protection Activities include acceptance criteria against which corrective action will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, Protective Coatings Program, Gas Systems Component Inspection, Passive Component Inspection Activities, and Fire Protection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.3 Aging Management Review for Commodity External Surfaces exposed to a Buried or Embedded Environment

This evaluation applies to the external surfaces of all inscope mechanical process components that are buried or embedded. Buried and embedded components are fabricated from the following materials: stainless steel, carbon steel, and copper.

Systems

- E11 – Residual Heat Removal (2.3.3.2)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)
- T46 – Standby Gas Treatment (2.3.3.6)
- Y52 – Fuel Oil Supply (2.3.4.19)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.10.1) due to general corrosion, galvanic corrosion, selective leaching, pitting, crevice corrosion, and microbiologically influenced corrosion (MIC).

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Passive Component Inspection Activities* (A.3.5)
- *PSW and RHRSW Inspection Program* (A.1.13)
- *Inservice Inspection Program* (A.1.9)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material Occurring on the Exterior surfaces of Buried In Scope Components

The *Protective Coatings Program* provides a method to ensure protective coatings are correctly applied. Underground piping is covered with a protective coating that is expected to greatly reduce the rates of corrosion occurring on the external surfaces of buried piping. Plant service water, residual heat removal service water, standby gas treatment, HPCI, RCIC, and diesel fuel supply piping were coated with enamel and wrapped with a fiber wrap saturated in coal tar in accordance with AWWA C203-66 when buried. These coatings are expected to prevent corrosion except in those small areas where the coating is breached due to wear.

The *Fire Protection Activities* provides for regular operation and performance testing of fire suppression systems, including water based suppression systems, compressed gas based suppression systems, and fire pump diesel fuel oil supply system. Loss of performance or inventory due to significant leakage of underground piping could be detected by this program.

The *PSW and RHRSW Inspection Program* includes provisions for cleaning, priming, coating, and wrapping underground pipelines within the P41 and E11 systems whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping.

The *Passive Component Inspection Activities* serves to validate the adequacy of the piping coatings in mitigating loss of material by performing inspections of component surfaces anytime an applicable component is unearthed for repair. This information is carefully evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

For PSW and RHRSW piping, the *ISI Program* performs leakage tests that determine the rate of pressure loss or change in flow between the ends of buried piping such that leakage can be determined.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that many deficiencies were written that related to component exteriors for buried piping segments. Failures of buried components due to corrosion in areas where gaps in the existing coating have occurred during the life of the plant. No failures have been identified where the coating had been properly installed. However, there is some concern over the continued viability of the coating over the extended life of the plant. Programs have been added to address that concern.

Table C.2.4.3-1 Aging Management Program Assessment, External Surfaces of Buried Commodities: Loss of Material due to Corrosion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The PSW and RHRSW Inspection Program, ISI Program, Passive Component Inspection Activities, and Protective Coatings Program include the commodities under consideration in this evaluation.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides for coating of underground piping to mitigate or prevent corrosion.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections; the Passive Components Inspection Activities provide for visual or surface inspections; the Protective Coatings Program provides for visual inspections; and the PSW and RHRSW Inspection Program provides for visual, surface, or volumetric inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Passive Component Inspection Activities and PSW and RHRSW Inspection Program provide for inspection of buried component surfaces whenever they become accessible. The ISI Program provides tests that detect aging degradation.
5. Monitoring and trending for timely corrective actions.	The PSW and RHRSW Inspection Program, Passive Component Inspection Activities, and ISI Program provide trending of data to ensure proper corrective actions.
6. Acceptance criteria are included.	The PSW and RHRSW Inspection Program, Passive Component Inspection Activities, ISI Program, and Protective Coatings Program include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program, PSW and RHRSW Inspection Program, Passive Component Inspection Activities, ISI Program, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.4 Evaluation of Plant Insulation Commodities

This commodity group includes insulation and associated jacketing for in-scope components installed on ECCS, plant service water and RHR service water system components.

Thermal insulation serves to maintain design calculation limits, provided freeze protection, and prevent overheating of ECCS diagonals and HPCI pump rooms. The metallic jackets and fasteners serve to protect the insulation from environmental attack and fix the insulation in place.

C.2.4.4.1 Aging Management Review for Insulation

This commodity group includes insulation, L36 (2.3.4.3), installed on inscope ECCS, plant service water and RHR service water system components.

Systems

Insulation evaluated is installed on the following systems:

- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.11.1) due to wear and intrusion of water borne agents.
- *Cracking* (C.1.2.11.2) due to thermal effects and intrusion of water borne agents.
- *Change in Material Properties* (C.1.2.11.3) due to compaction and settling, material separation, intrusion of water and water-borne agents, and thermal effects.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Equipment and Piping Insulation Monitoring Program* (A.2.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking, and Change in Material Properties

No reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant Hatch will occur slowly and would be adequately managed by a focused inspection program. The *Equipment and Piping Insulation Monitoring Program* meets this requirement by providing periodic visual inspections of insulation components.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the L36 system. These deficiencies were screened to determine which ones might be potentially age-related. Several deficiencies were related to damaged, torn, or missing insulation. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system. Only one record that related to generally deteriorated insulation was discovered. This deterioration was confined to a small area and was not determined to significantly affect the thermal performance of the insulated system.

Table C.2.4.4-1 Aging Management Program Assessment, Insulation: Deterioration of Insulation due to Loss of Material, Cracking, and Change in Material Properties

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Equipment and Piping Insulation Monitoring Program governs aging management for the components under consideration in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Equipment and Piping Insulation Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Equipment and Piping Insulation Monitoring Program provides timely tests/inspections for detecting degradation.
5. Monitoring and trending for timely corrective actions.	The Equipment and Piping Insulation Monitoring Program provides for timely corrective actions upon discovery of unacceptable conditions.
6. Acceptance criteria are included.	The Equipment and Piping Insulation Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Equipment and Piping Insulation Monitoring Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.4.4.2 Aging Management Review for Insulation Jacketing

This commodity group includes metal jacketing and fasteners for insulation installed on Class 2 and 3 components. The in-scope insulation jacketing components are installed on ECCS, plant service water and RHR service water system components. Jackets and fasteners are fabricated from stainless steel, galvanized steel and aluminum alloys. These components are part of the L36 system (2.3.4.3).

Systems

Insulation jacketing is installed on the following systems:

- E11 – Residual Heat Removal (2.3.3.2)
- E21 – Core Spray (2.3.3.3)
- E41 – High Pressure Coolant Injection (2.3.3.4)
- E51 – Reactor Core Isolation Cooling (2.3.3.5)
- P41 – Plant Service Water (2.3.4.7)

Aging Effects Requiring Management

- *Loss of material* (C.1.2.8 and C.1.2.9) due to general corrosion, galvanic corrosion; pitting, crevice corrosion, and MIC.
- *Cracking* (C.1.2.8 and C.1.2.9) due to thermal fatigue.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Equipment and Piping Insulation Monitoring Program* (A.2.4)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking within insulation Metallic Jacketing Materials

No reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant Hatch will occur slowly and would be adequately managed by a focused inspection program. The *Equipment and*

Piping Insulation Monitoring Program meets this requirement by providing regular, focused inspections of insulation components.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that several deficiencies were written on the L36 system. These deficiencies were screened to determine which ones might be potentially age-related. Several deficiencies were related to damaged, torn, or missing jacketing. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system.

Table C.2.4.4-2 Aging Management Program Assessment, Insulation Jacketing: Deterioration of Insulation Jacketing due to Loss of Material and Cracking

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Equipment and Piping Insulation Monitoring Program governs aging management for the components under consideration in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	For degradation of components within this plant commodity group, the Equipment and Piping Insulation Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Equipment and Piping Insulation Monitoring Program provides timely tests/inspections for detecting degradation.
5. Monitoring and trending for timely corrective actions.	The Equipment and Piping Insulation Monitoring Program provides for timely corrective actions upon discovery of unacceptable conditions.
6. Acceptance criteria are included.	The Equipment and Piping Insulation Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Corrective Actions Program and Equipment and Piping Insulation Monitoring Program ensure corrective action will be accomplished, including root cause determination and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.5 AGING MANAGEMENT REVIEWS FOR ELECTRICAL DISCIPLINE COMMODITIES

C.2.5.1 Aging Management Review for Phase Bussing

This commodity group includes phase bussing with an internal environment of "Self Heating" and an external environment of "Inside" (excluding containment). The commodity is associated with the bus between 4160/600 volt station auxiliary transformer CD and 600V buses C and D.

Systems

- S11 – Power Transformers (2.5.13)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 122 deficiencies had been written on the S11 system. These deficiencies were conservatively screened to determine which ones might be potentially age-related. No age-related failures of the in-scope phase bussing components were found.

C.2.5.2 Aging Management Review for Nelson Frames

This commodity group includes Nelson Electric Multi-Cable Transit Frames (Nelson Frame) located in the walls and floors of the reactor building with an external environment of "Inside" (excluding containment). Some are located in the wall between the reactor building and turbine building. Some are located in the wall between the reactor building and control building. Others are located between floors of the reactor building. Floor mounted frames are mounted on concrete pedestals. Reactor building electrical penetrations allow cables to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

Systems

- T54 – Reactor Building Penetrations (2.4.7)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that no deficiencies had been written on the T54 system. No age-related failures of the in-scope Nelson Frame components were found.

C.2.5.3 Aging Management Review for Electrical Splices, Connectors, and Terminal Blocks

This commodity group includes electrical splices, connectors, and terminal blocks with an external environment of "inside" or "outside." The commodities are located throughout the plant, in the drywell, and in outdoor pits.

Systems

Plant-wide.

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that numerous deficiencies had been written on electrical splices, connectors, and terminal blocks. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-four failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, or involving equipment which is not in scope.

C.2.5.4 Aging Management Review for Insulated Electrical Cable Outside Containment

This commodity group includes insulated electrical cable located at Plant Hatch with an external environment of "Inside" and "Outside." Some cables could be exposed to submergence. This evaluation includes low and medium voltage cable and I & C cable.

Systems

Plant-wide.

Aging Effects Requiring Management

- Change in Insulation Resistance (C.1.3) due to water treeing or water intrusion in submerged cables only.

Comparing the elevations of the conduits in the pull boxes with the pull box water levels, it was determined that conduits containing safety-related circuits are exposed to moisture for some period of time between pull box inspections. This is detrimental to the insulated cable in the duct runs.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Wetted Cable Activity* (A.1.16).

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

The outdoor pull boxes are checked for water level quarterly and drained if necessary.

Megger testing is performed on the feeder cable back to the switchgear for RHRSW and PSW pump motors along with the leads from the surge pack to the motor.

Megger testing is performed on the feeder cables back to the switchgear for core spray and RHR pump motors along with the leads to the motor. Megger testing is not performed on transformer feeder cables.

Megger testing provides evidence of gross cable insulation deficiencies. Corrective actions are taken if megger readings are unacceptable.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 753 deficiencies had been written on electrical cable. These results were obtained in two ways. First, a review of the deficiencies for all systems was performed in order to obtain all that pertained to cable. Then, a printout of the deficiency database was run using keyword "cable." Both processes yielded virtually the same results. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-eight cable failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, involving wiring in complex active assemblies, or involving equipment which is not in scope.

Davis-Besse experienced the failure of a 5 kV power cable on October 2, 1999. The failed cable had a neoprene jacket and was run partially underground in PVC conduit. Neoprene is one of the least tolerant jacket materials with respect to moisture absorption. Neoprene jacketed cables are not used in outdoor duct runs at Plant Hatch.

Table C.2.5.4-1 Aging Management Program Assessment, Change in Insulation Resistance Due to Water Immersion

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Wetted Cable Activity governs aging management for the component within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Wetted Cable Activity requires quarterly draining of pull boxes if sufficient amounts of water are detected.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Wetted Cable Activities provide for visual inspections or performance testing.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Wetted Cable Activity specifies that the method of detection of cable insulation damage is by megger testing. The frequency of performance is based on repetitive task intervals.
5. Monitoring and trending are included for timely corrective actions.	The Wetted Cable Activity monitors and trends data to ensure the proper performance of the associated system equipment.
6. Acceptance criteria are included.	The Wetted Cable Activity provides detailed acceptance criteria related to pull box water levels and megger testing.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Wetted Cable Activity ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and are adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.5.5 Aging Management Review for Insulated Electrical Cable – Containment

This commodity group includes instrumentation and control cable for the neutron monitoring system, and installed communication equipment, with an external environment of "inside." These cables are located in the drywell. Radiation detectors are replaced on a neutronics depletion schedule. Part of the cable is replaced with the detector. The cable that is replaced goes from the detector to a junction box outside the subpile room. The cable being addressed in this AMR summary is the portion from the subpile room junction boxes to the electrical penetration assemblies.

Systems

- C71 – Reactor Protection System (2.5.4) (C51 – neutron monitoring system cables only)
- R51 – Installed Communication Equipment (2.5.12)

Aging Effects Requiring Management

None.

Aging Management Programs

None required.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 showed that approximately 753 deficiencies had been written on electrical cable. These results were obtained in two ways. First, a review of the deficiencies for all systems was performed in order to obtain all that pertained to cable. Then, a printout of the deficiency database was run using keyword "cable." Both processes yielded virtually the same results. These deficiencies were conservatively screened to determine which ones might be potentially age-related. Twenty-eight cable failures were found which could potentially be age-related. After further review, all of the failures were dismissed as either being event driven, involving EQ components, involving wiring in complex active assemblies, or involving equipment which is not in scope.

C.2.6 AGING MANAGEMENT REVIEWS FOR CIVIL DISCIPLINE COMMODITIES

C.2.6.1 Aging Management Review for Concrete Structures

This commodity group includes concrete components (i.e., walls, beams, slabs, columns, floors, roof, underground duct runs and pull boxes, foundations including those for equipment) and masonry block walls in several Class 1 structures listed below.

Systems

- T23 – Primary Containment (2.4.3)
- T24 – Fuel Storage (2.4.4)

- T29 – Reactor Building (2.4.5)
- U29 – Turbine Building (2.4.8)
- W35 – Intake Structure (2.4.9)
- Y29 – Yard Structures (2.4.10)
- Y32 – Main Stack (2.4.11)
- Y39 – Diesel Generator Building (2.4.12)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- *Loss of Material* (C.1.4.2) Cracking and Spalling due to corrosion of embedded steel
- *Cracking* (C.1.4.2) in masonry block walls (applicable to reactor and control buildings, and main stack only)

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Protective Coatings Program* (A.2.3)
- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material, Cracking, and Spalling due to Corrosion of Embedded Steel, and Cracking in Masonry Block Walls

The *Structural Monitoring Program* (SMP) inspection process assesses the ongoing overall conditions of the listed structures, and identifies any ongoing degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

The *Protective Coatings Program* provides for the prevention and mitigation for corrosion of embedded steel at the surface of the concrete.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified three concrete related deficiencies; one each was written on the T23, T29, and W35 functions. These deficiencies were screened to determine which ones might be potentially age related. No age-related deficiencies or failures of the in-scope T23, T24, T29, U29, W35, Y29, Y32, Y39, and Z29 components were found.

The ground water chemistry has been reviewed since the late 1960's for pH, chloride, and sulfate concentrations. No known conditions exist which would modify the ground water chemistry from that which has existed since the plant was constructed. Also, based on a discussion with personnel of Watershed Planning and Monitoring Program branch of the Georgia Environmental Protection Division, it is unlikely that pH, sulfates, and chlorides in the water of the Altamaha River would change appreciably. The more recent information indicates values that are considered well within acceptable limits to prevent aggressive chemical attack on concrete structures. The temperature range and atmospheric pollution are within the ranges used in the original design and construction of the plant.

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a "base-line" condition of the subject buildings and structures. Areas within the scope of the Maintenance Rule were visually inspected and photographs were made to document notable degrees of degradation. Specific items and areas included in the inspections were the roof, settlement around the building, outer concrete walls and penetrations, interior concrete columns, beams, floors, walls, interior steel superstructure columns, girders and beams, foundations, anchor bolts, and equipment slabs. Specific items and areas also included in the inspection of the sealants were the outer precast concrete wall panels and the CST transfer pump wall joints. All inspected areas were found "Acceptable-no further evaluation required." Condition surveys were conducted in April 1997 and November 1997. The inspection reports concluded the same findings as previous reports. Previous results of settlement surveys, and associated calculations, were also reviewed and all structures were found to be within acceptable settlement limits.

NRC I&E Bulletin No. 80-11 identified several masonry block walls that needed to be investigated for possible inadequate structural strength. SNC identified such walls and provided modifications to meet the requirements of this bulletin. Plant Hatch found no age-related degradation in the masonry block walls. The NRC concluded that Hatch had appropriately complied with requirements of the Bulletin and no further work was required beyond normal inspections and evaluations which were committed to in response to the Bulletin. NRC also revisited Plant Hatch several years later and assured themselves of proper maintenance of the block walls per the requirements of I&E Bulletin 80-11.

Table C.2.6.1-1 Aging Management Program Assessment, Concrete Structures: Loss of Material, Cracking and Spalling due to Corrosion of Embedded Steel in Concrete

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program, under the Maintenance Rule, includes the concrete components within the scope of aging management review. The Protective Coatings Program includes the embedded steel at the surface of the concrete.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program provides preventive actions that mitigate or prevent corrosion of embedded steel at the concrete surface.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	The aging effects requiring management for the concrete components in Class I structures and the turbine building are readily detectable by visual inspection. The Structural Monitoring Program performs visual inspections, which are evaluated to determine the structural impact of any degradation noted.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program inspects the Class 1 structures on a 5-cycle schedule, except for the Intake Structure and the Condenser Bay in the Turbine Building which are inspected during every cycle.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and evaluation to assure timely, corrective, or mitigative actions. The SMP records the results for evaluation purposes, and attempts to rectify them before the next inspection.
6. Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with Structural Monitoring Program inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Table C.2.6.1-2 Aging Management Program Assessment, Concrete Structures: Cracking in Masonry Block Walls in Reactor and Control Buildings, and in Main Stack

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program, under the Maintenance Rule, includes the masonry block walls located in the Reactor and Control Buildings and in the Main Stack.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	The aging effects requiring management for the masonry block walls identified in item 1 above are readily detectable by visual inspection. The Structural Monitoring Program performs visual inspections, which are evaluated to determine the structural impact of any degradation noted.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program inspects the Reactor and Control Buildings and the Main Stack on a 5-cycle schedule.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and evaluation to assure timely, corrective or mitigative actions. The Structural Monitoring Program records the results for evaluation purposes, and attempts to rectify them before the next inspection.
6. Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with Structural Monitoring Program inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.2 Aging Management Review for Steel Primary Containment and Internals

This commodity group includes steel commodities for primary containment, primary containment penetrations, and containment internal structures. The materials of construction for the drywell shell, torus, penetrations and internal structures consist of a variety of carbon steels and stainless steels. Carbon steels are galvanized or coated with an inorganic zinc primer and epoxy topcoat.

Systems

- T23 – Primary Containment (2.4.3)
- T52 – Drywell Penetrations (2.4.6)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to general corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC).
- *Cracking* (C.1.4.1) due to fatigue of the torus.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Inservice Inspection Program (ISI Program)* (A.1.9)
- *Primary Containment Leak Rate Testing Program* (A.1.14)
- *Component Cyclic or Transient Limit Program* (A.1.12)
- *Protective Coatings Program* (A.2.3)
- *Suppression Pool Chemistry Control* (A.1.7)
- *Passive Component Inspection Activities* (A.3.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

Primary Containment Leak Rate Testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections are conducted in accordance with 10 CFR 50, Appendix J.

The *Protective Coatings Program* provides for periodic inspection of structural component surfaces, including fasteners and associated service level I coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The *ISI Program* provides for visual inspections of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Suppression Pool Chemistry Control limits detrimental impurities and conductivity within the suppression pool and thereby mitigates aging. Suppression Pool Chemistry Control implements the EPRI guidance on BWR water chemistry for auxiliary systems.

The *Passive Component Inspection Activities* serve to validate the adequacy of the drywell floor and equipment sump discharge piping sections to perform a primary containment function by performing inspections, similar to VT-1, of component internal surfaces anytime an applicable component is opened for periodic maintenance or repair. This information is evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

Management of Cracking due to Fatigue of the Torus

The *Component Cyclic or Transient Limit Program* is designed to track cyclic and transient occurrences, including the limiting location for the torus, to ensure that reactor coolant pressure boundary components will remain within the ASME Code Section III limits.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 62 deficiencies had been written on the T23 and T52 systems. These deficiencies were screened to determine which ones might be potentially age-related. Ten of the deficiencies resulted from age-related degradation of the in-scope components due to minor corrosion. There were no component functional failures. These deficiencies were discovered during required visual inspections and pressure testing. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.2-1 Aging Management Program Assessment, Steel Commodities for Primary Containment and Internals: Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and Microbiologically Influenced Corrosion (MIC)

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The ISI Program, Protective Coatings Program, Primary Containment Leak Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control, include visual inspections and testing of primary containment and specifically includes corrosion as a monitored aging effect.
2. Preventive actions to mitigate or prevent aging degradation.	The Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements. Suppression Pool Chemistry Control is designed to mitigate age related degradation by limiting conductivity and impurities.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Inservice Inspection Program provides for visual, surface, or volumetric inspections, the Passive Components Inspection Activities provide for visual or surface inspections, the Primary Containment Leakage Rate Testing Program provides for visual inspections and performance testing, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The ISI Program, Passive Component Inspection Activities, and Protective Coatings Program require visual inspections of the primary containment and internals on a regular scheduled basis. Leak rate testing is also performed on a regular scheduled basis via the Primary Containment Leakage Rate Testing Program.
5. Monitoring and trending is included for timely corrective actions.	The ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, and Passive Component Inspection Activities require the monitoring of degradation and utilize the Corrective Action Program to implement timely corrective action.
6. Acceptance criteria are included	The ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control establish acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, ISI Program, Protective Coatings Program, Primary Containment Leakage Rate Testing Program, Passive Component Inspection Activities, and Suppression Pool Chemistry Control ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

Table C.2.6.2-2 Aging Management Program Assessment, Steel Commodities for Primary Containment and Internals: Cracking Due to Fatigue of the Torus

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity (SCC) for the identified aging effect.	The Component Cyclic or Transient Limit Program tracks the SRV discharges to the torus and provides specific limitations and acceptance criteria related to the CUF of the torus.
2. Preventive actions to mitigate or prevent aging degradation.	The Component Cyclic or Transient Limit Program is designed to prevent unacceptable fatigue leading to cracking of the torus.
3. Parameters monitored or inspected are linked to the degradation of the particular SCC intended function.	The Component Cyclic or Transient Limit Program monitors the CUF of the torus. The CUF is directly linked to prevention of cracking due to fatigue. The program provides specific acceptance criteria related to a CUF<1.0 for the torus.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Component Cyclic or Transient Limit Program provides for monitoring of the torus CUF once per operating cycle.
5. Monitoring and trending for timely corrective actions.	The Component Cyclic or Transient Limit Program monitors and trends torus CUF data to ensure that a CUF<1.0 is maintained at all times.
6. Acceptance criteria are included.	The Component Cyclic or Transient Limit Program provides, via monitoring of the CUF of the torus, detailed acceptance criteria to prevent fatigue cracking of the torus.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	The Component Cyclic or Transient Limit Program provides for tracking of the torus CUF and the Corrective Actions Program provides a method for tracking and resolving deficiencies.
8. Confirmation process is included.	The Corrective Actions Program provides a means to ensure that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs and activities. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities in order to prevent future occurrences.

C.2.6.3 Aging Management Review for Steel Structures in Seismic Category I Buildings, the Turbine Building and Category I Yard Structures

This commodity group includes steel and nonferrous commodities for Seismic Category I buildings and structures and select Category II buildings and structures important to the safety of Category I structures. This includes the reactor buildings, control building, river intake structure, diesel generator building, main stack, condensate storage tank foundations and containment walls, liquid nitrogen storage tank foundations, service water valve boxes, turbine building, Fire protection pump house foundation, and an exterior portion of the radwaste buildings. The materials of construction consist of carbon steels, stainless steels, and copper alloy. Carbon steels are coated with an inorganic zinc primer and epoxy topcoat or galvanizing.

Systems

- F15 – Refueling Equipment (2.3.4.2)
- L48 – Access Doors (2.3.4.4)
- T24 – Fuel Storage (2.4.4)
- T29 – Reactor Building (2.4.5)
- T31 – Cranes, Hoists, and ElevatorsSec2.pdf (2.3.4.13)
- T38 – Tornado Vents System (2.3.4.14)
- T54 – Reactor Building Penetrations (2.4.7)
- U29 – Turbine Building (2.4.8)
- W33 – Traveling Water Screens/Trash Racks System (2.3.4.16)
- W35 – Intake Structure (2.4.9)
- Y29 – Yard Structures (2.4.10)
- Y32 – Main Stack (2.4.11)
- Y39 – Diesel Generator Building (2.4.12)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- *Loss of Material* (C.1.4.1) due to general corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC) of carbon steel and of submerged stainless steel components.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Structural Monitoring Program* (A.2.5)
- *Protective Coatings Program* (A.2.3)
- *Overhead Crane and Refueling Platform Inspections* (A.1.10)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

The *Structural Monitoring Program* provides for the visual inspection of structural components on a scheduled basis. The SMP will inspect structural components for loss of material due to general corrosion.

The *Protective Coatings Program* provides for inspection of structural component surfaces, including fasteners. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The *Overhead and Refueling Platform Crane Inspection Program* provides for the visual inspection and testing of the reactor building overhead cranes and crane rail supports, and refueling platform to assure safe operation of the cranes.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 40 deficiencies had been written on the systems listed above. These deficiencies were screened to determine which ones might be potentially age-related. Four of the deficiencies resulted from age-related degradation due to corrosion of the in-scope components. There were no component functional failures. These deficiencies were discovered during visual inspections and routine surveillances. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a "base-line" condition of the subject buildings and structures. Areas within the scope of the Maintenance Rule were visually inspected and photographs were made to document notable degrees of degradation. Specific items and areas included in the inspections were penetrations steel, interior steel superstructure columns, girders and beams, anchor bolts, and embedded steel in walls, floors, and equipment slabs. Also included in the inspections were structural steel and miscellaneous steel, bolts, and anchors located outside in the applicable structures in the scope of the Structural Monitoring Program. All inspected areas were found "Acceptable- no further evaluation required." Condition surveys were conducted in April 1997 and November 1997. The inspection reports concluded the same findings as previous reports. Previous results of settlement surveys, and associated calculations, were also reviewed and all structures were found to be within acceptable settlement limits.

Table C.2.6.3-1 Aging Management Program Assessment for Steel Structures, Loss of Material Due to General Corrosion

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program and Protective Coatings Program includes all of the Class 1 buildings and the Turbine building and specifically includes corrosion as a monitored aging effect. The Overhead Crane and Refueling Platform Inspections require frequent inspection of load bearing steel components for corrosion.
2.	Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, the Overhead Crane and Refueling Platform Inspection provides for visual inspections or performance testing, and the Protective Coatings Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the Turbine building on a regular scheduled basis based on historical performance. Overhead Crane and Refueling Platform Inspections require frequent visual inspections. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions. The SMP requires inspection of the subject buildings and structures on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6.	Acceptance criteria are included	The Structural Monitoring Program, Overhead Crane and Refueling Platform Inspections, and Protective Coatings Program include acceptance criteria against which corrective actions related to corrosion are evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program, Overhead Crane and Refueling Platform Inspections, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental effects.

Table C.2.6.3-2 Aging Management Program Assessment for Steel Structures, Loss of Material Due to Crevice Corrosion, Pitting, and Microbiologically Influenced Corrosion (MIC)

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program and Protective Coatings Program includes all of the Class 1 buildings and the Turbine building and specifically includes corrosion as a monitored aging effect.
2. Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program provides preventive actions that mitigate or prevent loss of material due to corrosion by maintaining the applied surface coatings.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, and the Protective Coatings Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the Turbine building on a regular scheduled basis based on historical performance The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions. The SMP requires inspection of the subject buildings and structures on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6. Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective actions related to corrosion are evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structural Monitoring Program, and Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental effects.

C.2.6.4 Aging Management Review for Component Supports

This commodity group includes steel and aluminum commodities for select Seismic Category I and Seismic Category II/I components and component supports. This includes:

- Supports for piping, ducts and tubing
- Cable trays, conduits and supports for cable trays and conduits
- Electrical panels and supports
- Instrument racks and supports

The materials of construction consist of a variety of carbon steels, stainless steels and aluminum. Carbon steels are coated with an inorganic zinc primer and epoxy topcoat or galvanizing.

Systems

- H11 – Main Control Room Panels (2.5.8)
- H21 – In-plant Auxiliary Control Panels (2.5.9)
- L35 – Piping Specialties (2.4.1)
- R33 – Conduits, Raceways, and Trays (2.4.2)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to general corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC) of carbon steel and of submerged stainless steel components.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Structural Monitoring Program* (A.2.5)
- *Protective Coatings Program* (A.2.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to General Corrosion, Crevice Corrosion, Pitting, and MIC

The *Structural Monitoring Program* provides for the visual inspection of component supports on a scheduled basis. The SMP inspects component supports made of carbon steel for loss of material due to general corrosion.

The *Protective Coatings Program* provides for periodic inspection of structural component surfaces, including fasteners. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that approximately 200 deficiencies had been written on the H11, H21, L35, and R33 systems which involved the subject components and supports. These deficiencies were screened to determine which ones might be potentially age-related. Twenty-three deficiencies resulted from age-related degradation of the in-scope components. These deficiencies were discovered during visual inspections and routine surveillances. The deficiencies were due to corrosion of support base plates or other carbon steel component subjected to standing water. There were no component functional failures. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.4-1 Aging Management Program Assessment for Component Supports: Loss of Material Due to General Corrosion, Crevice Corrosion, Pitting and Microbiologically Influenced Corrosion (MIC)

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes visual inspections of safety-related and Seismic II/I components and component supports for corrosion. The Protective Coatings Program applies to all structures and components which are susceptible to and experience corrosion.
2.	Preventive actions to mitigate or prevent aging degradation.	Protective Coatings Program minimizes age related degradation by specifying recommended grades of protective coating and surface preparation requirements.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections, and the Protective Coatings Program provides for visual inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspections of in-scope components and component supports on a regular scheduled basis. The Protective Coatings Program provides for periodic inspections of components in this commodity group.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a regular scheduled basis. The Protective Coatings Program provides for monitoring and trending of deficiencies.
6.	Acceptance criteria are included	The Structural Monitoring Program and Protective Coatings Program include acceptance criteria against which corrective action related to corrosion will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, the Structural Monitoring Program, and the Protective Coatings Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events. It requires that reasonable actions be taken to enhance programs and activities to prevent recurrence of detrimental effects.

C.2.6.5 Aging Management Review for Spent Fuel Pool Liner, Components, and Racks

This commodity group includes:

- Spent fuel pool liner, plugs, gates, storage racks, bolting, and miscellaneous steel inside the spent fuel pool.

The material of construction is stainless steel. All these components are exposed to an environment of demineralized water.

Systems

- T24 – Fuel Storage (2.4.4)

Aging Effects Requiring Management

- *Loss of Material* (C.1.2.2.1) due to crevice corrosion, pitting, and microbiologically influenced corrosion (MIC)

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fuel Pool Chemistry Control* (A.1.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to crevice corrosion, pitting, MIC

Fuel Pool Chemistry Control provides for mitigation of loss of material within the fuel pool by limiting detrimental impurities and conductivity. Fuel pool water quality is monitored on a weekly basis and corrective actions are taken in the event that limits are exceeded. Fuel Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that no deficiency was written on the T24 system related to loss of material due to crevice corrosion, pitting, or MIC.

Table C.2.6.5-1 Aging Management Program Assessment, SFP Liner, Components & Racks: Loss of Material due to MIC, Pitting and Crevice Corrosion in the Stainless Steel Liner & Components located in the Spent Fuel Pool and Refueling Canal

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Fuel Pool Chemistry Control governs the components included in this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	Fuel Pool Chemistry Control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Also, this program accomplishes timely monitoring and goal setting for degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	Due to chemistry controls, this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	Due to chemistry controls, this attribute of aging management is not required.
5. Monitoring and trending is included for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included	Fuel Pool Chemistry Control provides detailed acceptance criteria to insure proper orientation of the demineralizers within the SFP.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	Fuel Pool Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies, and includes root cause determination.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls are present for the program or procedures.	The Corrective Actions Program provides for the control of plant procedures and records associated with the chemical sampling inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.6 Aging Management Review for Aluminum

This commodity group includes aluminum used at Plant Hatch in various environments as listed below:

- Aluminum countersunk head rivet for fuel/control rod handling in the reactor building
- Aluminum seismic restraints for the fuel storage racks in the spent fuel pool
- Aluminum storage rack components in the new fuel storage vault
- Aluminum cover plates and clip angles in the pull boxes (yard structures)
- Aluminum support frame for tornado relief vents
- Aluminum blowout panels and fasteners in the steam chase walls between the reactor building and turbine building

The aluminum seismic restraints for the fuel storage racks in the spent fuel pool are exposed to an environment of demineralized water. The countersunk head rivet in the fuel/control rod handling platform, storage rack components in the new fuel storage vault and aluminum blowout panels and fasteners in the steam chase are exposed to air. The predominant environment for the pull boxes is outside, which indicates the structures are exposed to normal outside weather conditions. The aluminum support frames for tornado relief vents are exposed to an inside environment as well as an outside environment (atmosphere).

Systems

- F15 – Refueling Equipment (2.3.4.2)
- T24 – Fuel Storage (2.4.4)
- T29 – Reactor Building (2.4.5)
- T38 – Tornado Relief Vents (2.3.4.14)
- Y29 – Yard Structures (2.4.10)
- Z29 – Control Building (2.4.13)

Aging Effects Requiring Management

- Loss of Material (C.1.4.1) due to galvanic corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion (MIC), applicable only to the aluminum seismic restraints for the fuel storage racks in the spent fuel pool demineralized water.

This aging effect is applicable to the spent fuel pool seismic restraints.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Fuel Pool Chemistry Control* (A.1.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Material due to Galvanic corrosion, Crevice Corrosion, Pitting, and MIC

Fuel Pool Chemistry Control provides for mitigation of loss of material within the fuel pool by limiting detrimental impurities and conductivity. Fuel pool water quality is monitored on a weekly basis and corrective actions are taken in the event that limits are exceeded. Fuel Pool Chemistry Control implements the guidance of EPRI BWR water chemistry guidelines.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that no deficiency was written on the F15, T24, T29, T38, Y29, and Z29 systems related to loss of material due to galvanic corrosion, pitting, and MIC.

Table C.2.6.6-1 Aging Management Program Assessment, Aluminum: Loss of Material Due to Galvanic corrosion, MIC, Pitting and Crevice Corrosion of Aluminum components within the Spent Fuel Pool

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	Fuel Pool Chemistry Control governs aging management of the Aluminum components within the spent fuel pool.
2. Preventive actions to mitigate or prevent aging degradation.	Fuel Pool Chemistry Control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Also, this program accomplishes timely monitoring and goal setting for degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	Due to chemistry controls, this attribute of aging management is not required.
4. The method of detection of the aging effects is described and performed in a timely manner.	Due to chemistry controls, this attribute of aging management is not required.
5. Monitoring and trending for timely corrective actions.	Due to chemistry controls, this attribute of aging management is not required.
6. Acceptance criteria are included.	Fuel Pool Chemistry Control provides detailed acceptance criteria to insure proper orientation of the demineralizers within the SFP.
7. Corrective actions, including root cause determination and prevention of recurrence, are included.	Fuel Pool Chemistry Control provides for analyses of significant chemistry events, along with corrective actions to prevent future occurrences. The Corrective Actions Program provides a method for tracking and resolving deficiencies, and includes root cause determination.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with the chemical sampling inspections.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.7 Aging Management Review for Structural Sealants

This commodity group includes sealants and seal materials which are utilized in safety-related structures and components, are required for structural integrity of safety-related structures, and perform these functions without moving parts or change in configuration and properties. These sealants are typically not replaced based on qualified life or specified time period and are subject to aging. This includes:

- Joint seal and caulk sealant in the joint between the reactor building exterior precast panels.
- Main control room environmental control system (MCRECS) duct flange gaskets and flex connectors.

Systems

- T29 – Reactor Building (2.4.5)
- Z41 – Control Building HVAC (2.3.4.20)

Aging Effects Requiring Management

- *Material property changes and cracking* (C.1.4.3) due to thermal exposure for reactor building joint seal and caulk sealant and the MCRECS duct flange gaskets and flex connectors.
- *Loss of Adhesion* (C.1.4.3) due to exposure to excessive moisture for reactor building joint seal and caulk sealant.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage aging effects requiring management are as follows:

- *Passive Component Inspection Activities* (A.3.5)
- *Structural Monitoring Program* (A.2.5)
- *Gas Systems Component Inspections* (A.3.3)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links.

Demonstration of Aging Management

What follows is a demonstration that the aging effects requiring management identified will be adequately managed during the period of extended operation.

Management of Loss of Adhesion, Material Property Changes, and Cracking

The Structural Monitoring Program provides for the visual inspection of reactor building joint seal and caulk sealant on a scheduled basis.

The *Gas Systems Component Inspections* provides for a one time visual inspection of a representative sample of systems with dry and wetted gas internal environments to provide objective evidence that the aging effects for systems with gases as internal environments are being adequately managed for MCRECS duct flange gaskets and flex connectors.

The *Passive Component Inspection Activities* provides for the detailed visual inspection of internals of selected plant equipment, including HVAC ducts, and the collection, trending, and reporting of aging related degradation for MCRECS duct flange gaskets and flex connectors.

Review of Operating Experience

A review of the condition reporting database, discussed in section 3.0, identified that a relatively small number of deficiencies had been written on sealants important to the function of structures for the systems listed above. These deficiencies were screened to determine which ones might be potentially age-related. There were two deficiencies identified which resulted from age-related degradation of the in-scope components. These deficiencies were due to deterioration of a portion of the sealant (caulk) and backing rod in the joint between the reactor building exterior precast panels. No deficiencies were found to be associated with the control room duct gasket or flex connector material. The deficiencies were discovered during visual inspections and routine surveillances. The *Corrective Actions Program* was utilized to correct/repair these deficiencies.

Table C.2.6.7-1 Aging Management Program Assessment, Structural Sealants: Material Property Changes and Cracking due to Thermal Exposure

Attributes		Aging Management Program/Procedure
1.	Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the Class 1 buildings and turbine building and addresses structural integrity. The Passive Component Inspection Activities includes the MCRECS ductwork. The Gas Systems Component Inspections include systems exposed to internal gas environments.
2.	Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3.	Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Passive Components Inspection Activities provide for visual or surface inspections, the Structural Monitoring Program provides for visual inspections, and the Gas Systems Component Inspections provide for visual, surface, or volumetric inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the turbine building on a regular basis. The Passive Component Inspection Activities and Gas Systems Component Inspections include the MCRECS duct flex connectors and duct flange gaskets.
5.	Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis. The Passive Component Inspection Activities occurs on a frequency that is consistent with other component inspections.
6.	Acceptance criteria are included	The Structural Monitoring Program, Gas Systems Component Inspections, and Passive Component Inspection Activities include acceptance criteria against which corrective action will be evaluated.
7.	Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program, Structuring Monitoring Program, Gas Systems Component Inspections, and Passive Component Inspection Activities ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8.	Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9.	Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides control of plant procedures and records.
10.	Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent the recurrence of detrimental aging effects.

Table C.2.6.7-2 Aging Management Program Assessment, Structural Sealants: Loss of Adhesion due to Exposure to Excessive Moisture

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the reactor building exterior precast panel joint seals and caulk sealant.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the Class 1 buildings and the turbine building on a regular basis.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis.
6. Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.6.8 Aging Management Review for Tornado Relief Vent Assemblies

This commodity group includes tornado relief vent assemblies that are utilized in safety-related structures, and are required for containment and structural integrity of safety-related structures. Though these components are considered active assemblies, they are considered in-scope for structural integrity purposes. These vents are typically not replaced based on qualified life or specified time period and are subject to aging. This commodity group includes:

- Acrylic dome

Systems

- T38 – Tornado Vent System (2.3.4.14)

Aging Effects Requiring Management

- *Cracking* (C.1.4.4) due to weathering of acrylic material.

A complete discussion of the applicable aging effect determinations may be found in section C.1 of the LRA or by using the above links.

Aging Management Programs

Aging management programs determined to manage applicable aging effects are as follows:

- *Structural Monitoring Program* (A.2.5)

A complete discussion of the applicable aging management programs may be found in Appendix A of the LRA or by using the above links. What follows is a demonstration that the applicable aging effects identified will be adequately managed during the period of extended operation.

Demonstration of Aging Management

The *Structural Monitoring Program* provides for periodic visual inspections of the tornado vent assemblies for cracking due to weathering.

Review of Operating Experience

Only one deficiency written on tornado vents important to the intended function was identified as resulting from age-related degradation of the in-scope components. This deficiency was due to cracking of the dome material due to weathering. The deficiency was discovered during visual inspections and routine surveillance. The *Corrective Actions Program* was utilized to correct/repair this deficiency. There was no functional failure of the tornado roof vent system or secondary containment.

The tornado relief vent assemblies have been replaced once to repair degraded domes in December 1993. The vents were replaced on the Control and Turbine building roofs. Additional vent domes were added to the Reactor Building roof on top of existing vent domes.

Table C.2.6.8-1 Aging Management Program Assessment, Tornado Relief Vents: Cracking

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific Structure, component or commodity for the identified aging effect.	The Structural Monitoring Program includes the tornado vents on the Reactor building.
2. Preventive actions to mitigate or prevent aging degradation.	No program is required to prevent or mitigate aging degradation.
3. Parameters monitored or inspected are linked to the degradation of the particular function.	For degradation of components within this plant commodity group, the Structural Monitoring Program provides for visual inspections.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Structural Monitoring Program requires visual inspection of the reactor building in which the tornado vents are located, on a periodic basis.
5. Monitoring and trending is included for timely corrective actions.	The Structural Monitoring Program provides for monitoring and trending to assure timely corrective or mitigative actions on a scheduled basis.
6. Acceptance criteria are included	The Structural Monitoring Program includes acceptance criteria against which corrective action will be evaluated.
7. Corrective actions, including root cause determination and prevention of recurrence are included.	The Corrective Actions Program and the Structural Monitoring Program ensure corrective action will be accomplished, including root cause determinations and actions to prevent recurrence.
8. Confirmation process is included.	The Corrective Actions Program assures that corrective and preventive actions are accomplished and adequate.
9. Administrative controls should provide a formal review and approval process.	The Corrective Actions Program provides for the control of plant procedures and records associated with aging management programs. These controls include a formal review and approval process.
10. Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.	The Corrective Actions Program provides for evaluation of aging affects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

C.2.7 REFERENCES

C.2.7.1 Documents Incorporated by Reference into the Hatch LRA.

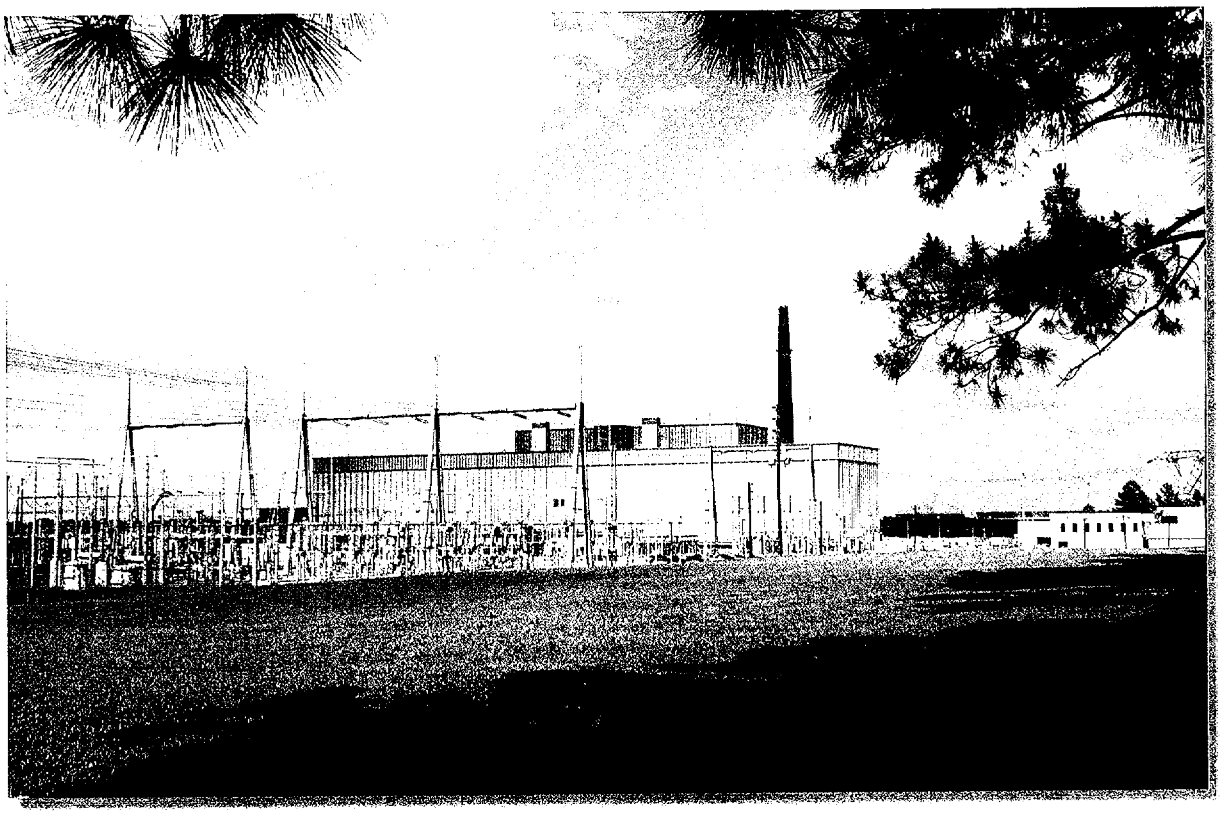
1. (BWRVIP-74), "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," Electric Power Research Institute (EPRI) TR-113596, September 1999.
2. (BWRVIP-27), "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," EPRI TR-107286, April 1997.
3. (BWRVIP-38), "BWR Shroud Support Inspection and Flaw Evaluation Guidelines," EPRI TR-108823, September 1997.
4. (BWRVIP-41), "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," EPRI TR-108728, October 1997.
5. (BWRVIP-48), "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," EPRI TR-108724, February 1998.
6. (BWRVIP-76), "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," EPRI TR114232, November 1999.
7. (BWRVIP-18), "BWR Core Spray Internals and Flaw Evaluation Guidelines," EPRI TR-106740, July 1996.
8. (BWRVIP-26), "BWR Top Guide Inspection and Flaw Evaluation Guidelines," EPRI TR-107285, December 1996.
9. (BWRVIP-47), "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," EPRI TR-108727, December 1997.

C.2.7.2 General References

- (BWRVIP 29), "BWR Water Chemistry Guidelines," EPRI TR-103515-R1, December 1996.
- EPRI TR-106092 "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Coolant Systems," September 1997.
- EPRI NSAC/202-L, "Recommendations for an Effective Flow-Accelerated Corrosion Program."
- EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines," October 1997.
- EPRI NP-5461, "Component Life Estimation: LWR Structural Materials Degradation Mechanisms," September 1987.
- ASME Boiler and Pressure Vessel Code, 1989 Edition, July 1989.
- Generic Letter 88-01 "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," 1988.
- NRC NUREG 0619 "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking, resolution of Generic Technical Activity A 10," November 1980.
- Appendix G to Part 50 of Title 10 of the Code of Federal Regulations, "Fracture Toughness Requirements," December 1995.

- Appendix H to Part 50 of Title 10 of the Code of Federal Regulations, "Reactor Vessel Material Surveillance Program Requirements," December 1995.
- Part 54 of Title 10 of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," May 1995.
- (BWRVIP-01), "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," Revision 2, EPRI TR-107079, October 1996.
- (BWRVIP-07), "Guidelines for Reinspection of BWR Core Shrouds," EPRI TR 105747, February 1996.
- (BWRVIP-63), "BWR Vessel and Internals Program Shroud Vertical Weld Inspection and Evaluation Guidelines," June 1999.
- NRC Generic Letter 91-17 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," October 1991.
- EPRI NP-5769 "Degradation and Failure of Bolting in Nuclear Power Plants," Vols. 1 and 2, Project 2520-7, 1988.
- NUREG 1339 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," 1990.
- Generic Letter 89-13 with Supplement 1 "Service Water System Problems Affecting Safety-Related Equipment," 1990.
- AWWA C203 (American Water Works Association) "AWWA Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines - Enamel and Tape – Hot Applied," 1966 Edition.
- Edwin I. Hatch Nuclear Plant Units 1 and 1 Environmental Qualification Central File.
- NRC I. E. Bulletin 80-11 "Masonry Wall Design," May 1980.
- NRC Information Notice 92-20 "Inadequate Local Leak Rate Testing," March 1992.
- NRC Information Notice 91-46 "Degradation of Emergency Diesel Generator Fuel Oil Deliver Systems," July 1991.
- NRC Generic Letter 92-08 "Thermo-Lag 330-1 Fire Barriers," December 1992.

Edwin I. Hatch Nuclear Plant
License Renewal Application



Volume 2

SOUTHERN COMPANY
Energy to Serve Your World®

Appendix D

Applicant's Environmental Report – Operating License Renewal Stage Edwin I. Hatch Nuclear Plant

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

LIST OF TABLES

TABLE OF CONTENTS (CONTINUED)

LIST OF FIGURES

ACRONYMS

AEC	Atomic Energy Commission
BTU	British Thermal Unit
CFR	Code of Federal Regulations
DOE	U.S. Department of Energy
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
EPD	Environmental Protection Division
FES	Final Environmental Statement
GADNR	Georgia Department of Natural Resources
GEIS	Generic Environmental Impact Statement
GPC	Georgia Power Company
HNP	Edwin I. Hatch Nuclear Plant
IPE	Independent Plant Examination
kV	kilovolt
MW	Megawatt
NEPA	National Environmental Policy Act
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
SAMA	Severe Accident Mitigation Alternative
SMITTR	Surveillance, On-line Monitoring, Inspections, Testing, Trending, and Recordkeeping
SNC	Southern Nuclear Operating Company

1.0 INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act and implementing NRC regulations. Southern Nuclear Operating Company (SNC) operates the Edwin I. Hatch Nuclear Plant (HNP) Units 1 and 2 pursuant to NRC Operating Licenses DPR-57 and NPF-5, respectively. HNP Unit 1 began commercial operation December 31, 1975, and is licensed to operate through August 6, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed to operate through June 13, 2018. SNC has prepared this environmental report in connection with its application to NRC, as provided for by NRC regulation, to renew the HNP licenses.

The purpose and need for the proposed action, HNP license renewal, as stated by NRC is as follows:

> 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. (Volume 61 Number 251 Federal Register [FR] pages 28467 - 28496, at page 28472)

The renewed operating licenses would allow for 20 additional years of plant operation beyond the current HNP licensed operation period of 40 years.

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

The NRC regulations, at 10 CFR 51.53(c)[1], require that an applicant for renewal of a license to operate a nuclear power plant submit with its application a separate document entitled "Applicant's Environmental Report - Operating License Renewal Stage." In determining the information to include in the HNP Environmental Report, SNC has relied on the regulatory language and the following supporting documents that provide insight into the regulatory requirements:

- NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," May 1996
- NUREG-1440, "Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses," May 1996
- NUREG-1529, "Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response," May 1996
- DG-4005, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," Draft, July 1998

It is SNC's understanding that NRC will use this environmental report as input in preparing a supplemental environmental impact statement (EIS) for HNP license renewal. SNC has

1. Title 10, Code of Federal Regulations, Part 51, Section 51.53(c).

organized this environmental report to reflect NRC EIS format guidance.[2] Therefore, the environmental report format should facilitate NRC review and EIS preparation. Table 1-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In turn, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

1.3 HATCH NUCLEAR PLANT LICENSEE AND OWNERSHIP

The HNP is co-owned by Georgia Power Company (GPC), Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the city of Dalton, Georgia. GPC built HNP and had sole responsibility for the operation of the plant through March 21, 1997. Pursuant to an application dated September 18, 1992, the NRC issued an operating license amendment on March 17, 1997, effective March 22, 1997, designating SNC as the exclusive operating licensee of HNP. As the sole operating licensee, SNC is responsible for the planning, design, licensing, operation, maintenance, repair, modification, license renewal, and retirement and decommissioning of HNP pursuant to a Nuclear Operating Agreement between SNC and GPC (Reference 1). Southern Company, based in Atlanta, Georgia, is the parent company of five electric utilities (Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric) as well as Southern Nuclear Operating Company (SNC), which provides services to Southern Company's nuclear power plants.

2. 10 CFR 51, Subpart A, Attachment A, as adopted by reference at 10 CFR 51.70(b).

Table 1-1. Environmental report responses to license renewal environmental regulatory requirements.

Regulatory requirement	Responsive environmental report section		Support sections
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)	2.1	Proposed Action	
10 CFR 51.53(c)(2)	2.1.7	Modifications	
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	3.2	Alternatives	2.2
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)	1.1	Purpose of and Need for Action	
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	3.3.1	Unavoidable Adverse Impacts	3.1
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	3.4	Short-Term Use Versus Long-Term Productivity	3.1
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	3.3.2	Irreversible or Irretrievable Resource Commitments	3.3.1
10 CFR 51.53(c)(3)(ii)(A)	3.1.2	Water Use	2.1.4, Attachment B
10 CFR 51.53(c)(3)(ii)(C)	3.1.3	Groundwater Use	2.1.5
10 CFR 51.53(c)(3)(ii)(E)	3.1.4	Terrestrial Resources	2.1.7
10 CFR 51.53(c)(3)(ii)(E)	3.1.5	Threatened and Endangered Species	2.1.7, Attachment C
10 CFR 51.53(c)(3)(ii)(F)	3.1.6	Air Quality	2.1.7
10 CFR 51.53(c)(3)(ii)(G)	3.1.7	Microbial Organisms	2.1.3, Attachment E
10 CFR 51.53(c)(3)(ii)(H)	3.1.8	Electric Shock	2.1.6
10 CFR 51.53(c)(3)(ii)(I)	3.1.9	Housing Impacts	2.1.7, 2.1.8
10 CFR 51.53(c)(3)(ii)(I)	3.1.10	Public Services, Public Utilities	2.1.7, 2.1.8, 3.1.3
10 CFR 51.53(c)(3)(ii)(I)	3.1.11	Public Services, Education	2.1.7, 2.1.8
10 CFR 51.53(c)(3)(ii)(I)	3.1.12	Offsite Land Use, Refurbishment	2.1.7, 2.1.8
10 CFR 51.53(c)(3)(ii)(I)	3.1.13	Offsite Land Use, License Renewal Term	2.1.8
10 CFR 51.53(c)(3)(ii)(J)	3.1.14	Public Services, Transportation	2.1.7, 2.1.8
10 CFR 51.53(c)(3)(ii)(K)	3.1.15	Historic and Archaeological Resources	2.1.7, Attachment D
10 CFR 51.53(c)(3)(ii)(L)	3.1.16	Severe Accident Mitigation Alternatives	Attachment F
10 CFR 51.53(c)(3)(iv)	3.1.17	New and Significant Information	
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	Chapter 4	Compliance Status	Attachments C and D

2.0 PROPOSED ACTION AND ALTERNATIVES

2.1 PROPOSED ACTION

The proposed action is the renewal of existing NRC operating licenses for Edwin I. Hatch Nuclear Plant Units 1 and 2, which are operated in accordance with NRC operating licenses NPF-5 and DPR-57, respectively. HNP Unit 1 began commercial operation December 31, 1975, and is licensed to operate through August 6, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed to operate through June 13, 2018. NRC regulations (10 CFR Part 54) allow license renewal for periods of up to 20 years, which would extend the operation of Unit 1 through August 6, 2034 and extend the operation of Unit 2 through June 13, 2038.

2.1.1 General Plant Information

The Edwin I. Hatch Nuclear Plant (HNP) is a steam-electric generating facility operated by Southern Nuclear Operating Company (SNC). The Plant is located in Appling County, Georgia, southeast of where U.S. Highway 1 crosses the Altamaha River. It is approximately 11 miles north of Baxley, Georgia; 98 miles southeast of Macon, Georgia; 73 miles northwest of Brunswick, Georgia; and 67 miles southwest of Savannah, Georgia. The Universal Transverse Mercator coordinates of the Unit 2 reactor (to the nearest 100 meters) are Zone 17R LF 3,533,700 meters North and 372,900 meters East. These coordinates correspond to latitude 31 degrees, 56 minutes, and 4 seconds North and longitude 82 degrees, 20 minutes, and 39 seconds West. Figures 2-1 and 2-2 illustrate the HNP location.

The HNP is a two-unit plant. Each unit is equipped with a General Electric Nuclear Steam Supply System that utilizes a boiling-water reactor with a Mark I containment design. Both units were originally rated at 2,436 megawatts-thermal and designed for a power level corresponding to approximately 2,537 megawatts-thermal. Both units are now licensed for 2,763 megawatts-thermal (63 FR 53473-53478, October 5, 1998). The Plant uses a closed-loop system for main condenser cooling that withdraws from and discharges to the Altamaha River via shoreline intake and offshore discharge structures. Descriptions of HNP can be found in documentation submitted to U.S. Nuclear Regulatory Commission (NRC) for the original operating license and subsequent license amendments. Georgia Power Company (GPC) submitted environmental reports for the construction stage and operating license stage for HNP in 1971 and 1976, respectively (References 2 and 3). In 1972, the Atomic Energy Commission (AEC)[3] issued a Final Environmental Statement (FES) for Units 1 and 2 (Reference 4), and in 1978 issued a FES for Unit 2 (Reference 5). The FESs evaluate the environmental impacts from plant construction and operation in accordance with the National Environmental Policy Act (NEPA).

The property at the HNP site totals approximately 2,240 acres and is characterized by low, rolling sandy hills that are predominantly forested. A property plan is shown in Figure 2-3. Figure 2-4 provides a more detailed site plan. The property includes approximately 900 acres north of the Altamaha River in Toombs County and approximately 1,340 acres south of the River in Appling County. All industrial facilities associated with the site are located in Appling County. The restricted area, which comprises the reactors, containment buildings, switchyard, cooling tower area and associated facilities, is approximately 300 acres (Figure 2-4). Approximately 1,600 acres are managed for timber production and wildlife habitat.

Controlled areas available for use with prior permission include a wildlife habitat area and a Boy Scout Camp. The wildlife habitat area is 75 acres of wetlands east of the restricted area. Efforts have been made in the past to interest ecological groups in conducting research in this wetland area. The 100-acre tract of land west of U.S. Highway 1 (Figure 2-3) is used as a Boy Scout

3. Predecessor agency to NRC.

Camp. A lease between GPC and the Area Council of the Boy Scouts of America allows scouting groups to use the Boy Scout Camping Area. In the past, the area has been used on weekends by Scouts, with the number using the area ranging between 25 and 50 per weekend. The area may be used in the future for Boy Scout Camporees that involve as many as 400 to 500 scouts.

Uncontrolled areas available to the public include a wayside park, a recreation area, and Visitors Center (Figure 2-3). The wayside park, east of Highway 1 and south of the River, provides simple recreational facilities overlooking the Altamaha River for public use. The area has parking and picnicking facilities, and can accommodate up to 10 groups at a time. The GPC Recreation Area is accessed by County Road 451, off U.S. Highway 1, south of the Plant entrance. This 13-acre facility includes softball fields, tennis courts, an archery range, swimming pool, and an office building which includes a multipurpose activities room. The facility is available to employees, their families, and guests. The Visitors Center is accessed from the main plant access road that originates at U.S. Highway 1. The Visitors Center includes hands-on exhibits on nuclear power and exhibits depicting the history of nuclear power, the history of HNP, and an environmental exhibit featuring the Altamaha River. The Visitors Center also includes an auditorium that seats approximately 70 people and conference rooms. The typical number of visitors is approximately 50 daily and 12,000 annually.

2.1.2 Nuclear Fuel and Radioactive Waste

The two HNP reactors are boiling water reactors operated at a maximum core thermal power output level of 2763 megawatts - thermal. HNP fuel is slightly enriched (currently 3.8, with an anticipated increase to 4.2, percent by weight) uranium dioxide in the form of high-density ceramic pellets stacked in zirconium alloy fuel rods. Each fuel rod consists of high-density fuel pellets stacked in a Zircaloy-2 cladding tube which is evacuated, back-filled with helium, and sealed by welding Zircaloy plugs in each end. Fuel assemblies at HNP are either 8 by 8 (62 fuel rods and 2 water rods), 9 by 9 (79 fuel rods and 2 water rods), or 10 by 10 (92 fuel rods and 2 water rods) arrays. Different U-235 enrichments are used within each fuel assembly to reduce the local power peaking factor. SNC currently operates HNP at an equilibrium core average fuel discharge burnup rate of 42,100 megawatt-days per metric ton uranium (MWd/MTU), with a future goal of 45,000 MWd/MTU. HNP operates on a 18-month refueling cycle and currently stores all its spent nuclear fuel onsite in a spent fuel pool.

In 1994, a spent fuel storage expansion plan was prepared by Plant Hatch. The plan called for spent fuel pool re-work and the installation of an interim on-site storage facility in late 1999. The Plan recommended a dry storage system as the most desirable approach, using the DOE Multipurpose Canister (MPC) or an improved, NRC-certified dry storage container (cask) provided by an approved vendor. The dry storage area and pad, completed in 1999, have space for 48 dry cask storage systems.

HNP currently makes the following shipments of radioactive materials offsite by truck:

- HNP to high-level waste examination sites;
- HNP to a low-level waste disposal site (Barnwell, South Carolina);
- HNP to an offsite processing facility for segregation, recycling, compaction, incineration and disposal;
- Offsite processing facility to HNP for reuse or storage.

HNP also temporarily stores mixed waste onsite, consistent with NRC and U.S. Environmental Protection Agency (EPA) requirements. All HNP radioactive waste shipments are packaged in accordance with NRC and U.S. Department of Transportation requirements and regulations.

2.1.3 Heat Dissipation System

The excess heat produced by HNP's two nuclear units is absorbed by cooling water flowing through the condensers and the service water system. Main condenser cooling is provided by mechanical draft cooling towers. Each HNP circulating water system is a closed-loop cooling system that utilizes three cross-flow and one counter-flow mechanical-draft cooling towers for dissipating waste heat to the atmosphere.

Cooling tower makeup water for Units 1 and 2 is withdrawn from the Altamaha River through a single intake structure. The intake structure is located along the shoreline of the Altamaha River (Figure 2-3) and is positioned so that water is available to the plant at both minimum flow and probable flood conditions. The intake is approximately 150 feet long, 60 feet wide, and the roof is approximately 60 feet above normal river level. To account for varying river stages, the water passage entrances are from 16 feet below to 33 feet above normal water levels.

Water is returned to the Altamaha River via a submerged discharge structure that consists of two 42-inch lines extending approximately 120 feet out from the shore at an elevation of 54 feet mean sea level. The point of discharge is approximately 1,260 feet down-river from the intake structure and approximately 4 feet below the surface when the river is at its lowest level (Figure 2-3).

The National Pollutant Discharge Elimination System (NPDES) Permit for HNP (GA0004120) issued by the Environmental Protection Division (EPD) of the Georgia Department of Natural Resources (GA DNR) in 1997 requires weekly monitoring of discharge temperatures, but does not stipulate a maximum discharge temperature or maximum temperature rise across the condenser. Maximum discharge temperatures in the mixing box, which are reported to EPD on a quarterly basis, range from 62°F in winter to 94°F in summer (see Table 2-1).

To control biofouling of cooling system components such as condenser tubes and cooling towers, an oxidizing biocide (typically sodium hypochlorite or sodium bromide) is injected into the system as needed to maintain a concentration of free oxidant sufficient to kill most microbial organisms and algae. When the system is being treated, blowdown is secured to prevent the discharge of residual oxidant into the river. After biocide addition, water is recirculated within the system until residual oxidant levels are below discharge limits specified in the NPDES permit (GA0004120).

2.1.4 Surface Water Use

The Altamaha River is the major source of water for the plant. Water is withdrawn from the River to provide cooling for certain once-through loads and makeup water to the cooling towers. SNC is permitted (GADNR Permit 001-0690-01) to withdraw a monthly average of up to 72 million gallons per day with a maximum 24-hour rate of up to 103.6 million gallons. As a condition of this permit, SNC is required to monitor and report withdrawals. Table 2-2 provides the annual average daily withdrawal and the maximum daily withdrawal for the years 1989 through 1997. As shown in Table 2-2, HNP withdraws an annual average of 57.18 million gallons per day.

The evaluation of surface water use in the 1978 FES (Reference 5) concluded that the consumptive losses would be approximately 46 percent of the total water withdrawn from the River. In NRC's environmental assessment for an extended power uprate (Volume 63 Number 192 FR pages 53473-53478, at page 53474), NRC concluded that the necessary increase in makeup water to support the higher heat load would be insignificant and that cooling tower blowdown would decrease by approximately 626 gallons per minute. As evaluated by NRC in the extended power uprate review, consumptive water use for the plant operating at the extended power level is expected to be 57 percent of the total withdrawal (Reference 7).

2.1.5 Groundwater Use

HNP withdraws groundwater for potable and process use from the Floridan Aquifer. HNP is permitted (GADNR Permit 001-0001) to withdraw a monthly average of 1.1 million gallons per day or 764 gallons per minute with an annual average of 0.550 million gallons per day from 4 wells. Although the current permit indicates 4 onsite wells, there are actually only 3 wells providing groundwater for domestic and process use. The fourth well was intended to provide makeup water for a wildlife habitat pond that was not completed; and therefore, the well has not been installed.

Site Well Number 3 provides water for potable use only at the site recreational facility. Operation of this well as the source water supply for the GPC Recreation Facility potable water system is conducted under GADNR Permit NG0010011. Site Wells Number 1 and Number 2 provide water for potable use, sanitary facilities, and process use (e.g. demineralized water, fire protection). Operation of these wells as the source water supply for the Plant is conducted under GADNR Permit PG0010005. Figure 2-3 indicates the locations of the three production wells.

GADNR requires SNC to monitor and report withdrawal from these three wells. Table 2-3 lists the monthly withdrawal volumes and annual average pumping rates (in gallons per minute) from these wells for the period from 1990 to 1997. The two-unit operation requirements for this period averaged 126 gallons per minute with a high month (January 1992) average of 236 gallons per minute.

2.1.6 Transmission Facilities

GPC built four transmission lines for the specific purpose of connecting HNP to the transmission system. Two additional 500-kV lines were added to HNP in 1981 to support an expansion of the GPC transmission system to Florida. The additional two lines have been evaluated as part of this environmental report.

The list below identifies the lines by the name of the substation at which each line connects to the transmission system. The list indicates the general direction of line routes from HNP, voltage, date of construction, and whether NRC has previously analyzed the line. Figure 2-5 shows the locations of the lines and substations together with some regional features.

- Eastman Line – The 230-kilovolt (kV) Eastman line was constructed in 1972 and extends northwest from the Site. The AEC analyzed the environmental impacts of this line in the final environmental statement for HNP Unit 1 operation and Unit 2 construction (Reference 4 at pages III-1, IV-3, and V-1).

- S. Hazelhurst (Douglas) Line – The 230-kV Douglas line was constructed in 1971 and extends southwest from the Site. The environmental impacts of this line were analyzed by AEC in the 1972 FES (ibid.).

- North Tifton Line – The 500-kV North Tifton line was constructed in 1971 and extends southwest from the Site. AEC analyzed the environmental impacts of this line in the 1972 FES (ibid.).

- Bonaire Line – The 500-kV Bonaire line was constructed in 1976 and extends northwest from the Site. AEC analyzed the environmental impacts of this line in the 1972 and 1978 FESs (ibid. and Reference 5 at pages 2-1, 2-3, 2-6, 3-12, and 5-1 in the 1978 FES).

- Duval Line – The 500-kV Duval line was constructed in 1981 and extends south from the Site. AEC (and NRC) did not analyze this line because GPC constructed it after start of HNP Unit 2 operation.

- Thalmann Line – The 500-kV Thalmann line was constructed in 1981 and extends southeast from the Site. AEC (and NRC) did not analyze this line because GPC constructed it after start of HNP Unit 2 operation.

GPC constructed HNP adjacent to an existing 230-kV line from East Vidalia to Offerman and an existing 115-kV line from Vidalia and Baxley. GPC looped the East Vidalia-to-Offerman line into the HNP switchyard, creating the Hatch-to-East Vidalia and the Hatch-to-Offerman lines but did not construct the lines for the specific purpose of connecting HNP to the transmission system. As AEC noted, the loop was not a new line; therefore, this environmental report does not address them further. GPC sold the Eastman, Douglas, North Tifton, and Bonaire lines to Oglethorpe Power Corporation and Oglethorpe transferred maintenance responsibility to its subsidiary, Georgia Transmission Company. Georgia Transmission Company and GPC use similar maintenance practices, however, and the following discussions apply regardless of transmission line ownership.

HNP transmission lines constructed for the specific purpose of connecting HNP to the transmission system occupy four corridors. "Corridor" is a general term used to identify the land over which a transmission line travels. A utility can own the land, in which case it holds the corridor as a property owner. More commonly, others own the land and utilities own the right, called an easement, to install and maintain the transmission line on the land. In the case of an easement, the corridor is commonly called a right-of-way. Most HNP transmission line corridors are rights-of-way with 1 to 2 percent of the acreage being owned outright.

GPC established standard transmission corridor widths, as follows:

Line Voltage	Corridor Width
500 kV	150 feet
230 kV	125 feet
115 kV	100 feet

When transmission lines were adjacent, GPC reduced the corridor width by 25 feet. The following paragraphs describe the HNP transmission line corridors.

- Eastman/Bonaire Corridor – The Eastman and Bonaire lines share a 250-foot wide corridor for 53 miles to the vicinity of Eastman, Georgia. There, the Eastman line diverges for 4 miles into Eastman. The Bonaire line continues for another 37 miles to a substation near Bonaire, Georgia. After diverging from the Bonaire line, the Eastman line joins another 230-kV line going into Eastman. These lines form a 225-foot wide corridor, of which 125 feet is attributed to HNP. Similarly, within 11 miles of Bonaire, the Bonaire line joins several other lines to form a wider corridor, but only 150 feet are attributed to HNP. The total corridor area that is attributable to HNP is approximately 2,300 acres.[4]

- Douglas/North Tifton Corridor – The Douglas and North Tifton lines share a 250-foot wide corridor for 34 miles to a point north of Douglas, Georgia. There, the Douglas line turns south in a 125-foot wide corridor for the 10 miles to the GPC substation. The North Tifton

4. Total acreage is calculated by multiplying the length (feet) × width (feet) × 43,560 square feet per acre. For example [(53 miles × 5,280 feet per mile × 250 feet) + (4 miles × 5,280 feet per mile × 125 feet) + (37 miles × 5,280 feet per mile × 150 feet)] ÷ 43,560 square feet per acre = 2,340 acres.

line continues for 48 more miles in a 150-foot wide corridor to a substation near Tifton, Georgia. The total corridor area is approximately 2,100 acres.

- Duval Corridor – The Duval corridor extends 87 miles to the Florida state line, where Florida Power and Light Company takes ownership responsibility. The corridor width is 150 feet. For 20 miles of its length, from south of Baxley to Offerman, the Duval line shares a 250-foot wide corridor with a 230-kV line with 150 feet of its width attributed to HNP. The total corridor area is approximately 1,600 acres.

- Thalmann Corridor – The Thalmann corridor extends 65 miles to the GPC substation near Thalmann, Georgia. The corridor width is 150 feet. For 28 miles of its length, from Odum, Georgia, to Everett, Georgia, the Duval line shares a 225-foot wide corridor with a 115-kV line. For the last 7 miles into the GPC substation at Thalmann, Georgia, the Duval line shares a 275-foot wide corridor with another 500-kV line. For the shared corridors, 150 feet of the width is attributed to HNP. The total corridor area is approximately 1,200 acres.

In total, for the specific purpose of connecting HNP to the transmission system, HNP has approximately 340 miles[5] of transmission line corridors that occupy approximately 7,200 acres[6].

At this time, GPC is a vertically integrated electric utility. GPC as a part of its electricity generation, transmission and distribution business, plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. They will remain a permanent part of the transmission system after HNP is decommissioned.

HNP transmission line corridors pass through land that primarily is a mixture of cultivated land, grazing land, and managed timberlands (paper and pulp stock). Corridors that pass through farmlands generally continue to be used in this fashion. Corridors in timberlands and in the vicinity of road crossings are maintained on a 3-year cycle by mowing or, if inaccessible to mowers, by use of non-restricted-use herbicides.

GPC designed and constructed all HNP transmission lines in accordance with the edition of the National Electrical Safety Code® (Reference 9)[7] and industry guidance that was current when the line was built. Ongoing right-of-way supervision and maintenance of HNP transmission facilities ensures continued conformance to governing standards and includes routine aerial patrol, helicopter inspection, and ground inspection. At this time, routine aerial patrols of all corridors are conducted every other month and include checks for encroachments, broken conductors, broken or leaning structures, and signs of trees burning, any of which would be evidence of clearance problems. Slow helicopter inspections (45 miles per hour or less) are conducted annually for 500-kV lines to allow more careful checks of facilities and rights-of-way. Currently all lines are inspected from the ground and measured for clearance at questionable locations every 6 years. Problems noted during any inspection are brought to the attention of the appropriate organizations for corrective action.

---

5. Calculated as follows: 53 miles (Eastman and Bonaire lines) + 4 miles (Eastman line) + 37 miles (Bonaire line) + 34 miles (Douglas and North Tifton lines) + 10 miles (Douglas line) + 48 miles (North Tifton line) + 87 miles (Duval line) + 65 miles (Thalmann line) = 338 miles.
6. Calculated as follows: 2,340 acres (Eastman/Bonaire Corridor) + 2,055 acres (Douglas/Tifton Corridor) + 1,582 acres (Duval Corridor) + 1,182 acres (Thalmann Corridor) = 7,159 acres.
7. A publication that provides standards for safeguarding persons from hazards arising from the installation, operation, or maintenance of electric supply stations and electrical supply lines and equipment. The American National Standards Institute has recognized the NESC as a consensus standard.

2.1.7 Modifications

NRC

The report must contain a description of . . . the applicant's plans to modify the facility or its administrative control procedures as described in accordance with §54.21 of the Chapter. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment. [10 CFR 51.53(c)(2)]

The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item. (Generic Environmental Impact Statement Section 2.6.3.1, page 2-41.) [SMITTR defined at GEIS Section 2.4, page 2-30 as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping]

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS, Reference 10) identifies surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) and major refurbishment activities that utilities might perform for license renewal. Performing such SMITTR and major refurbishment activities would necessitate first changing administrative control procedures, and major refurbishment activities also would involve modifying the facility. This section describes HNP license renewal SMITTR and refurbishment plans to satisfy the NRC requirement to describe facility and administrative control procedure modification plans in accordance with 10 CFR Section 54.21

SMITTR Activities

The integrated plant assessment (IPA), required by 10 CFR Section 54.21, identified the programs and inspections managing aging effects at Plant Hatch. These programs are described in the Application for Renewed Operation Licenses, Plant E. I. Hatch, Units 1 and 2, Appendix A. SNC does not anticipate any additional personnel or resources above the current plant staffing will be required for the performance of the identified aging management programs.

Refurbishment Activities

SNC has completed the integrated plant assessment (IPA) required by 10 CFR Section 54.21 and determined that no refurbishment activities will be required for license renewal. Existing programs for surveillance, monitoring, inspections, testing and modifications to plant systems, structures, and components will continue in the period of extended operations as part of normal maintenance activities. Continuation of these programs will result in modifications to plant systems, structures, and components that are required to achieve performance improvements in the plant systems or by changes in regulations. The existing programs that control modifications at the plant require a review for environmental impact for each modification.

2.1.8 Employment

SNC has approximately 925 employees at HNP during routine operations. On-site vendor and contract staff vary throughout the year by as many as 50 workers, yielding a total on-site workforce that ranges between 925 and 975 during routine operations. In addition to the site employees, there are approximately 130 corporate staff dedicated to Plant Hatch who are located offsite in Birmingham, Alabama. The SNC employees employed at the site reside in 33 Georgia counties with more than 85 percent of the employees residing in the 5 counties listed below. The remaining employee residences are distributed throughout 28 counties, mostly within 50 miles of the site.

County	Number of Personnel	Percent of Total Personnel
Toombs	387	41
Appling	290	30
Montgomery	61	6
Tattnall	46	5
Jeff Davis	40	4
Other	129	14
Total	953	100

The on-site workforce increases by as many as 800 temporary (1 to 2 months) duty employees during refueling outages. HNP units are on an 18-month refueling interval, and SNC generally schedules outages on staggered schedules, resulting in one outage per year for two years and two outages in the third year (cycle repeats). The 800 temporary employees include contractors, employees from other SNC nuclear facilities, and corporate support staff.

During the license renewal period, SNC does not anticipate the need to increase on-site or off-site personnel and expects the outage workforce to be within the range supporting current operations. Strategic planning for HNP projects a constant or slightly reduced workforce in the future based on industry benchmarks for boiling-water-reactor units similar to HNP.

2.2 ALTERNATIVES

> ***NRC***
>
> ***The environmental report shall discuss "alternatives to the proposed action..." 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).***
>
> ***While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, 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. (GEIS Section 8.1)***
>
> ***The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area. (Supplementary information to Final Rule, 61 FR 66537 - 66554, December 18, 1996, at Section II.H, page 66541, column 3)***

NRC regulations require discussion of alternatives and draft NRC regulatory guidance (Reference 61) calls for discussion of the following:

- No action alternative, defined as the alternative of not renewing the license, and
- Alternatives that meet system generating needs, a refinement of the no-action alternative.

The electric generation needs for the state of Georgia are addressed by the joint planning of the joint owners and relative to Georgia Power and other investor-owned utilities integrated resource planning reviews conducted by the Georgia Public Service Commission, which regulates rates and other practices of investor-owned electric utilities. As indicated in Section 1.1, the purpose of the proposed action (license renewal) is to retain an option for meeting future system generating needs. Section 2.2 focuses on the range of alternatives that would also satisfy this purpose.

Section 2.2 begins with a discussion, called "no action," of activities that would take place if HNP did not seek renewal of operating licenses, regardless of what additional steps are taken to replace HNP generating capacity. Next, the section examines three scenarios that SNC has determined to be feasible alternatives for meeting system needs (coal-fired generation, gas-fired generation, and imported electric power). In considering the level of detail and analysis that it should provide for each alternative, SNC relied on the NRC decision-making standard for license renewal:

> . . . the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision-makers would be unreasonable. [10 CFR 51.95(c)(4)].

SNC determined that, as long as the environmental report provided sufficient information to clearly indicate whether an alternative would have comparable or greater environmental impact than the proposed action (i.e., license renewal), the document would contain sufficient information to support the NRC decision-making. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which require that the consideration of alternatives (including the proposed action) devote substantial enough treatment that reviewers may evaluate their comparative merits [40 CFR 1502.14(b)].

Section 2.2.2 provides only sufficient detail about feasible alternatives to establish the basis for necessary Chapter 3 analysis of impacts. Finally, Section 2.2.3 identifies other alternatives considered and discusses why SNC has determined that they are not feasible.

2.2.1 No Action

The no action alternative refers to a scenario in which SNC would decommission HNP after license expiration. HNP provided approximately 12,000,000 megawatt-hours (Reference 19) of electricity in 1997 to customers in Georgia via the Georgia Power Company electric grid that serves approximately 1.7 million customers in 57,000 square miles of the state (Reference 11). This 12,000,000 megawatt-hours represented approximately 12 percent of the electricity generated in the state of Georgia in 1997. SNC presumes that the HNP demand would be met by one of the generation alternatives presented in this document or in the GEIS. However, potential for deregulation of the electric retail market in Georgia and possible changes in wholesale supply of electricity may affect whether the joint owners will be the ultimate supplier of power to these customers. The range of feasible replacement power options is addressed in the following sections.

Regardless of license renewal, SNC will have to comply with NRC decommissioning requirements. When nuclear power plants permanently cease operation, they must be decommissioned in accordance with NRC regulations. The NRC defines decommissioning as safe removal from service, reduction of residual radioactivity to a level that permits release of the property, and termination of the NRC license (10 CFR 50.2). NRC regulations define acceptable levels of residual radioactivity. GEIS Section 7.3 provides a description of decommissioning activities. If NRC renews the HNP operating licenses, decommissioning would be postponed for an additional 20 years. If NRC does not renew the licenses, SNC would initiate decommissioning activities upon expiration of the current HNP operating licenses. Under the feasible alternatives addressed below, HNP decommissioning would be concurrent with operation of the alternatives. SNC adopts by reference the GEIS description of decommissioning activities, but notes that the description is based on a larger reactor (the GEIS "reference" boiling-water reactor is the Washington Public Power System's 1,155 megawatt-electric WNP-2 reactor).

2.2.2 Feasible Alternatives

In the GEIS, NRC discusses alternatives to license renewal of nuclear power generating units. The document states that coal- and gas-fired generation technologies are feasible alternatives to nuclear power plants based upon current technological and cost efficiencies, and generally discusses the types of impacts that would occur as a result of construction and operation of these types of facilities.

The principal fuel burned in Georgia's power plants is coal. As of August 1998, coal-fired units accounted for roughly 57 percent of the existing generation capacity in Georgia; nuclear generation (represented by SNC nuclear production units at Plant Hatch and Plant Vogtle) accounted for approximately 17 percent; oil- and gas-fired units combined accounted for approximately 11 percent; and hydroelectric generating facilities accounted for approximately 15 percent of capacity (Reference 11). Since coal-fired electric generation is currently widely utilized in Georgia, SNC considers this technology a feasible alternative to nuclear generation, and Section 2.2.2.1 presents coal as a feasible alternative to HNP license renewal. Gas-fired generation technology (combined cycle) offers efficiency improvements, pollutant emissions reductions, and fewer overall environmental impacts from plant operations (Reference 10) as compared to coal-fired generation. Further, capital costs are low, and lead time (from time at which need is identified to startup date) is relatively short. For these reasons, Section 2.2.2.2 presents gas-fired generation as a feasible alternative to HNP license renewal.

The alternatives presented assume that existing facilities and infrastructure would be used to the extent practicable, limiting the amount of new construction that would be required. Specifically, it is assumed that the alternatives would use the existing intake and discharge structures, switchyard, offices, and transmission line corridors. This was done primarily to minimize the predicted environmental impacts of these alternatives during construction. Using existing intake and discharge structures could also reduce operational impacts because it is reasonable to assume that aquatic communities in the immediate vicinity of the plant have already adapted to HNP patterns of water withdrawal and thermal discharge. Construction of new intake and discharge structures at a new site would necessitate aquatic community adaptations at the new site, adding to the environmental impact of the alternatives.[8] The gas-fired alternative could also make use of existing gas pipeline capacity located approximately 4.5 miles south of the Site. By utilizing existing structures such as these, the environmental impact of construction would be reduced. Although the alternatives are presented as construction at a defined site, the sections also discuss how design and site variations could affect the alternative definition and the resulting environmental consequences.

The descriptions of the coal-fired and gas-fired power plants utilized in this environmental report for the sake of comparison are intended to be reasonable representations of facilities that could be used as alternative sources of energy. The descriptions are based on a combination of several existing facilities that together include the major components and technology GPC would use as feasible alternate energy sources. SNC chose these facilities because they are recent projects that present current technology and are documented in publicly available reports. In addition, industry and government technical publications are cited as sources of technical data and information regarding the types and quality (e.g., ash content, British thermal units [BTU] per pound) of fossil fuels that might be burned at electrical power generating units. More detailed technical discussion defining representative coal- and gas-fired plants as alternative power sources is included in Section 2.2.2.1 and 2.2.2.2, respectively.

2.2.2.1 Coal-Fired Generation

Representative Plant

The primary source of information used to describe and size (megawatts and land use) the coal-fired alternative is Delmarva Power and Light Company documentation for its Dorchester Power Plant. In addition, documentation for the South Carolina Electric and Gas Company Cope Power Plant was also used. These facilities are typical of currently available coal-fired technology being constructed and operated today. Information from the EPA and the U.S. Department of Energy's (DOE's) Energy Information Administration technical publications on fuel specifications and best available emission control technology was utilized to specify fuel types and emission control technology for the alternative. In some cases, SNC uses referenced data directly; in other cases, SNC appropriately scaled data to fit the size plant needed for a HNP alternative energy source.

For the purposes of this environmental report, it is assumed that it would take 1,800 megawatts-electric (MWe) coal-fired generation to replace the 1,690-MWe HNP. The increased size over current HNP capacity would be necessary to offset increased internal electrical usage for auxiliary pollution control, pumping water for cooling, or coal or ash handling (Reference 14).

The typical size (megawatts) and configuration utilized by the electrical power industry in the application of coal-fired generation technology varies. Nationally, coal-fired unit sizes range up to more than 1,000 MWe (Reference 15). The Delmarva Power and Light Company and the South Carolina Electric and Gas Company sized and phased construction of their units to match load growth projections. The Delmarva power plant consists of two 300-MWe units constructed at the

8. Additionally, it is reasonable to assume that construction and operations at a new site would mean that intake and discharge at the HNP site would stop, necessitating adaptation of the HNP-site aquatic communities to the change in their environment.

same site sharing common facilities and infrastructure such as rail, fuel storage, and ash disposal (Reference 16). The Cope Power Plant consists of three 385-MWe pulverized coal-fired units (Reference 14).

The coal-fired alternative in this report would consist of three 600-MWe units (ISO rating)[9] that would burn pulverized bituminous coal. The choice of pulverized coal combustion technology, as opposed to other coal combustion technologies, is consistent with recent, regional practice for new generation capacity (e.g., South Carolina Electric and Gas Company's Cope Facility) and is considered a reasonable alternative (Reference 14). Bituminous coal is the most common coal burned in coal-fired units because of its higher heating values (Reference 17). Coal would have a heating value of 13,000 British Thermal Units (BTU) per pound, an ash content of 10 percent, and a sulfur content of 0.8 percent (Reference 18). A maximum of 15,500 tons[10] of coal and 880 tons of lime/limestone per day (Reference 14)[11] would be delivered by railcar on the existing rail spur that serves the HNP site (Figure 2-2).

Coal for the plant would be delivered by rail trains of 115 cars each. Each open-top rail car holds about 100 tons of coal (Reference 14). An additional 65 rail cars per week would be required to deliver the lime for plant operations. In all, approximately 520 trains per year, or an average of 10 trains each week, would deliver the coal and lime for all three units.[12] Since for each full train delivery, there is an empty train, a total of 20 train trips per week are expected.

Each of the three units would be 200-foot tall, tangentially-fired, dry-bottom boilers (Reference 17), and would include an approximately 600-foot stack (Reference 14). This firing configuration was chosen because of the moderate uncontrolled nitrogen oxides emissions from burning coal compared with other applications. Nitrogen oxides emissions controls would include low nitrogen oxide burners, overfire air, and post-combustion selective catalytic reduction. The combination of low nitrogen oxide burners and overfire air would achieve a nitrogen oxides reduction of 40 to 60 percent from uncontrolled levels. These combustion controls, along with selective catalytic reduction can achieve the current upper limit of nitrogen oxides control (95 percent reduction) (Reference 17). Based on an operating capacity factor of 83.9 percent (Reference 16), the resulting annual nitrogen oxides emissions would be approximately 570 tons per unit.[13]

Each unit would have fabric filters or electrostatic precipitators (99.9 percent particulate removal efficiency) and a wet lime/limestone flue gas de-sulfurization system (95 percent scrubber removal efficiency) (Reference 17). Based on an operating capacity factor of 83.9 percent (Reference 16), the resulting annual emissions per unit would be 79 tons of filterable

---

9. An ISO (International Standards Organization) rating identifies the generator rating at standard atmospheric conditions. Standard atmospheric conditions are 59°F, 60 percent relative humidity, and 14.696 pounds per square inch atmospheric pressure.
10. Calculate coal use as follows: 1,200-MW Cope Facility uses 3,760,000 tons coal per year. Therefore, 3,760,000 tons coal per 1,200 MW × 600 MW per unit ÷ 365 days per year × 3 units = 15,452 tons coal per day.
11. Calculate lime use as follows: 1,200-MW Cope Facility uses 215,000 tons of lime per year. Therefore, 215,000 tons of lime per 1,200 MW × 600 MW per unit ÷ 365 days per year × 3 units = 884 tons of lime per day.
12. Calculate number of trains as follows: 15,452 tons of coal per day × 365 days per year ÷ 100 tons of coal per rail car = 56,400 rail cars per year. For lime, 884 tons of lime per day × 365 days per year ÷ 95 tons of lime per rail car = 3,396 rail cars per year. 56,400 rail cars of coal per year + 3,396 rail cars of lime per year = 59,796 total rail cars per year. Assuming 115 rail cars per train, 59,796 rail cars per year ÷ 115 rail cars per year ÷ 52 weeks per year = 10 trains per week.
13. Calculated as follows using AP-42 (Reference 17) Table 1.1-3: 5,151 tons coal per day per unit × 365 days per year × 0.839 capacity factor × 14.4 pounds nitrogen oxides per ton coal ÷ 2,000 pounds per ton = 11,357 tons nitrogen oxides per year (uncontrolled). Assuming 95 percent reduction efficiency: 11,357 tons nitrogen oxides per year (uncontrolled) × 0.05 = 568 tons nitrogen oxides per year per unit (controlled).

particulates,[14] 18 tons of PM_{10},[15] and 1,200 tons of sulfur oxides.[16] Carbon monoxide emissions would be approximately 390 tons per year per unit.[17]

The plant would use the existing HNP intake, discharge structures, and cooling towers as part of a closed-loop cooling system. This alternative would minimize environmental impacts since minimal construction would be required to adapt the system to the coal-fired alternative. It is assumed that the coal-fired alternative would require a water use (including cooling water, wet scrubber sulfur oxides emission controls, and boiler makeup) volume of approximately 30 million gallons per day[18] which would be less than the existing HNP withdrawal of approximately 57 million gallons per day (Section 2.1.4). Based on the design and efficiency of the existing cooling towers, discharge temperatures would be less than or equal to those currently observed.

Construction of the coal-fired alternative would take approximately five years. The workforce during the construction period would average 1,500, with a peak of 2,000, and during operations would average 250. The reduced work force size for the coal-fired alternative (950 to 250) would reduce the groundwater withdrawals for potable water use. Assuming 35 gallons per day per person (Reference 14), maximum groundwater usage would be 8,750 gallons per day or 6.1 gallons per minute.

The power block and coal pile would occupy approximately 300 acres (Reference 16). The units would be constructed at the same time with phased-in service dates to replace the power demands supplied by HNP and would have an operational life of 40 years (Reference 14). Constructing more, smaller units instead of three 600-MWe units would offer no known environmental benefits.

Approximately 1.5 million tons of coal-combustion by-products per year (ash and scrubber sludge) would be disposed of onsite, requiring a plant lifetime (40 years) total of approximately 600 acres (Reference 14). Facilities would be constructed to control and treat leachate from coal storage areas and ash and scrubber sludge disposal areas. The existing switchyard and transmission system would be used. It is assumed that coal-fired generation structures and

---

14. Calculated using the uncontrolled emission factor for filterable particulates given in AP-42 Table 1.1-4 as 10A, where A is the weight percent ash of the coal as fired; therefore, 10 × 10 percent ash = 100 pounds filterable particulates per ton coal. Filterable particulate emission calculated as follows: 5,151 tons coal per day per unit × 365 days per year × 0.839 capacity factor × 100 pounds filterable particulates per ton coal ÷ 2,000 pounds per ton = 78,871 tons filterable particulates per year per unit (uncontrolled). Assuming 99.9 percent removal efficiency: 78,871 tons filterable particulates per year per unit (uncontrolled) × 0.001 = 79 tons filterable particulates per year per unit (controlled).
15. Calculated using the uncontrolled emission factor for PM_{10} given in AP-42 Table 1.1-4 as 2.3A, where A is the weight percent ash content of coal as fired; therefore, 2.3 × 10 = 23 pounds PM_{10} per ton of coal. PM_{10} emission calculated as follows: 5,151 tons coal per day per unit × 365 days per year × 0.839 capacity factor × 23 pounds PM_{10} per ton coal ÷ 2,000 pounds per ton = 18,140 tons PM_{10} per year per unit (uncontrolled). Assuming 99.9 percent removal efficiency: 18,140 tons PM_{10} per year per unit (uncontrolled) × 0.001 = 18 tons PM_{10} per year per unit (controlled).
16. Calculated using the uncontrolled emission factor for sulfur oxides given in AP-42 Table 1.1-3 as 38S, where S is the weight percent sulfur content of coal as fired; therefore, 38 × 0.8 = 30.4 pounds sulfur per ton coal. Sulfur oxides emission calculated as follows: 5,151 tons coal per day per unit × 365 days per year × 0.839 capacity factor × 30.4 pounds sulfur oxides per ton coal ÷ 2,000 pounds per ton = 23,977 tons sulfur oxides per year per unit (uncontrolled). Assuming 95 percent removal: 23,977 tons sulfur oxides per year per unit (uncontrolled) × 0.05 = 1,199 tons sulfur oxides per year per unit (controlled).
17. Calculated as follows using AP-42 Table 3.1-2: 5,151 tons coal per day per unit × 365 days per year × 0.839 capacity factor × 0.5 pound carbon monoxide per ton coal ÷ 2,000 pounds per ton = 394 tons carbon monoxide per year per unit.
18. Scaled from the SCE&G Cope facility (Reference 14) as follows: 1,200-MW unit uses 19,000,000 gallons per day. 19,000,000 gallons per day ÷ 2 600-MW units = 9,500,000 gallons per day per 600-MW unit × 3 600-MW units = 28,500,000 gallons per day for the 1,800 MW facility.

facilities, including coal storage and ash and scrubber sludge disposal areas, would all be located within the current HNP site boundaries.

As described above, the coal-fired generation alternative would necessitate converting an additional 900 acres of the HNP site to industrial use (plant, coal storage, ash and scrubber sludge disposal, and expansion of the onsite rail system to accommodate 115 unit coal trains). Currently, this land is mostly wooded, however, there are open areas in the vicinity of the existing plant.

New Site

Construction of the coal-fired generation alternative at a new site could impact up to 1,100 acres. In addition to the 900 acres needed for the plant, coal storage, and ash and scrubber sludge disposal areas described above, an additional 150 acres (Reference 16) for offices, roads, parking areas, and a switchyard would be required. Cooling water intake and discharge structures and mechanical or natural draft cooling towers would have to be constructed. An additional 300 acres would be needed for transmission lines, assuming the plant is sited 10 miles from the nearest substation.[19] An additional 160 acres would also be needed for a rail line for coal delivery[20] (assuming site location is 10 miles from nearest railway connection).

2.2.2.2 Gas-Fired Generation

Representative Plant

The primary source of information used to describe and scale for size (megawatt and land use) the gas-fired alternative is the EPA documentation for the Tampa Electric Company Polk Power Station (Reference 20). The Polk facility is typical of current available gas-fired technology being constructed and operated today. In addition, information from the EPA and DOE's Energy Information Administration technical publications on fuel specifications and best available emission control technology was utilized to specify fuel types and emission control technology that would be used in the gas-fired alternative. In some cases, SNC uses referenced data directly; in other cases, SNC appropriately scaled data to fit the size plant needed for a HNP alternative energy source.

For the purposes of this environmental report, it is assumed that it would take 1,760-MWe gas-fired generation to replace the 1,690-MWe HNP. The increase in generating capacity would be necessary to offset increased internal electrical usage for pollution control and pumping water for cooling, but would not be as great as for the coal-fired alternative due to reduced cooling water flow and pollution control needs.

There are several generation technologies that use natural gas as fuel. Gas-fired steam generator technology utilizes hot combustion gases to heat water to produce steam, which in turn rotates a generator to produce electricity. In simple-cycle combustion turbine technology, fuel is burned in a combustion turbine and the resulting hot combustion gases rotate the turbine to generate electricity before being emitted to the air. Combined-cycle technology uses a combination of combustion turbine technology and steam generator technology. In the combined cycle unit, hot combustion gases in the combustion turbine rotate the turbine to generate electricity; and waste combustion heat from the combustion turbine is routed through a heat recovery steam generator. There, water is turned to steam, which rotates a steam turbine to generate additional electricity. The size, type, and configuration of gas-fired generation units and plants currently operational in the United States vary and include simple-cycle combustion and

19. Based on 250-foot right-of-way (10 miles × 5,280 feet per mile × 250 feet ÷ 43,560 square feet per acre = 303 acres).
20. Based on 130-foot right-of-way (10 miles × 5,280 feet per mile × 130 feet ÷ 43,520 square feet per acre = 158 acres).

combined cycle units that range from 25 MWe to 600 MWe (References 20 and 21). As with coal-fired technology, units may be configured and combined at a location to produce the desired amount of megawatts, and construction can be phased to meet electrical power needs.

The gas-fired generation alternative consists of four 440-MWe (ISO rating) combined-cycle units each consisting of two 155-MWe simple-cycle combustion turbines and a 130-MWe heat recovery steam generator. On an average annual basis, these units would generate up to 440 MWe per hour each, providing the 1,760 MWe needed to replace HNP. The power block area and associated electrical facilities would occupy approximately 500 acres (Reference 21).

Natural gas typically having an average heating value of 1,000 BTU per cubic foot (Reference 11) would be the primary fuel; the gas-fired alternative plant would burn approximately 10 million cubic feet per hour (Reference 17). Low-sulfur No. 2 fuel oil would be the backup fuel (Reference 22). Natural gas would be delivered via an existing pipeline located approximately 4.5 miles from the HNP site (Figure 2-2). Approximately 55 acres would be disturbed during pipeline construction.[21] The existing line currently has sufficient reserve capacity to supply the needs of the gas-fired alternative.

Each unit would be less than 100 feet high and would be designed with dry, low nitrogen oxides combusters, water injection, and selective catalytic reduction (Reference 17), and would exhaust through a 230-foot stack after passing through heat recovery steam generators. This stack height is consistent with EPA Regulation 40 CFR 51.100, which addresses requirements for determining the stack height of new emission sources. Regulation 40 CFR 51.100 allows stack heights based on good engineering stack height (defined in the regulation) or modeling, but does not allow credit for offsite contaminant level reduction for taller stacks. The 230-foot height is based on the regulation's good engineering practice formula using the tallest proposed onsite facility (i.e., the 92-foot turbine building). While modeling would have to be used to justify stack height greater than 230 feet, the relatively flat terrain and low structures of the area probably mean that modeling would not support a greater stack height.

Nitrogen oxides emissions from the gas-fired alternative would be 386 tons per year.[22] There would be no solid waste products (i.e., ash) from natural gas fuel burning.

The plant would use the existing HNP intake and discharge and the existing mechanical cooling towers. Cooling requirements would be less; average withdrawal flows would be approximately 15 million gallons per day (Reference 64).

Construction of the gas-fired alternative would take approximately 3 years and the work force during the construction period would average 500, with a peak of 750. The work force during operations would average 125.

New Site

Construction of the gas-fired generation plant at a new site could impact approximately 600 acres. In addition to the 500 acres needed for the power block area and pipeline construction described above, approximately 100 acres would be required for offices, roads, parking areas,

21. Based on 100-foot right-of-way (4.5 miles × 5,280 feet per mile × 100 feet ÷ 43,560 square feet per acre = 55 acres).
22. Calculated as follows using AP-42 Table 3.1-2 and assuming a 60 percent thermal efficiency: 1,760 MW ÷ 0.6 = 2,933 MW input. 2,933 MW × (1 × 10^6 watts per MW) × (0.0009486 BTU per second per watt) × (60 seconds per minute) × (60 minutes per hour) × (24 hours per day) × (365 days per year) = (8.77 × 10^{13} BTU per year) × (0.0088 pounds nitrogen oxides per 1 × 10^6 BTU) × (1 ton per 2,000 pounds) = 386 tons nitrogen oxides per year.

and a switchyard. In addition, 300 acres would be needed for transmission lines, assuming the plant is sited 10 miles from the nearest substation.[23]

2.2.2.3 Imported Electrical Power

"Imported power" refers to power purchased and transmitted from electric generation plants that SNC does not own and that are located elsewhere within the region or nation. In 1995, Georgia was a substantial net seller of electricity. During 1995, the net interstate flow of electricity was -15,246 million kilowatt-hours or about 5 percent of all electricity produced in Georgia (Reference 11). During 1996, Southern Company facilities in Georgia (including those of subsidiaries Georgia Power and Savannah Electric) generated approximately 90 percent (90,000 million kilowatt-hours) of the power in Georgia (Reference 11). HNP generated approximately 13,000 million kilowatt-hours during 1996 (Reference 19).

Even though Georgia is a net exporter of electric power, GPC cannot discard imported power as a feasible alternative to HNP license renewal. Market conditions, particularly the anticipated free market created by deregulation, could result in a company finding it advantageous to import power to replace a retired Georgia plant while exporting other power generated in state. Such a situation could be caused by differential costs of generation or transmission, contractual relationships, or even strategic planning.

2.2.3 Other Alternatives

This section identifies alternatives to HNP license renewal that are not feasible, and describes why the alternatives are not feasible and will not be considered further in this environmental report.

Wind

Wind speeds in central and eastern Georgia (Macon and Savannah data) average 7.8 miles per hour (Reference 23), whereas average wind speeds of more than 13 miles per hour are required for wind turbines to generate electricity. Regions with wind speeds of this magnitude include the Great Plains, the West, coastal areas, and parts of the Appalachians (Reference 10). HNP is located approximately 80 miles inland (Reference 2). Based on the GEIS land use estimate for wind power,[24] replacement of HNP generating capacity, even assuming ideal wind conditions, would require dedication of almost 270,000 acres (422 square miles). The current HNP Site is about 2,244 acres (Section 2.1.1), and the county in which the facility is located is about 514 square miles (Reference 26). Based on the lack of adequate wind speeds and the amount of land that would be required for wind-powered generating facilities, SNC has determined that the wind alternative is not feasible.

Solar

Solar power technologies, photovoltaic and thermal, cannot currently compete with conventional fossil-fueled technologies in grid-connected applications due to higher capital costs per kilowatt of capacity. There also are substantial impacts to natural resources (wildlife habitat, land use, and aesthetic impacts) from construction of these facilities. It is estimated that at least 35,000 acres at a single site or at multiple sites would be required to build a 1,000 MW(e) facility. In addition, the HNP site receives less than 3.9 kilowatt-hours of solar radiation per square meter per day, compared to 5 to 7.2 kilowatt-hours of solar radiation per square meter per day in areas of the West, such as California, which are most promising for solar technologies (GEIS Sections 8.3.2

23. Based on 250-foot right-of-way (10 miles × 5,280 feet per mile × 250 feet ÷ 43,560 square feet per acre = 303 acres).
24. GEIS Section 8.3.1 estimates 150,000 acres per 1,000 megawatts-electric for wind power.

and 8.3.3). Because of the natural resource impacts, the area's low rate of solar radiation and high technology costs, SNC views the role of solar power in Georgia as limited to niche applications and not a feasible baseload alternative to HNP license renewal.

Hydropower

Approximately 15 percent, or 3,412 MWe, of Georgia's generating capacity is hydroelectric (Reference 11). As GEIS Section 8.3.4 points out, hydropower's percentage of the country's generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses. Based on the GEIS land use estimate for hydroelectric power of 1 million acres per 1,000 megawatts-electric, replacement of HNP generating capacity would require flooding more than 2,800 square miles. Due to the large land-use and related environmental and ecological resource impacts associated with siting a hydroelectric facility large enough to replace HNP, SNC has determined that this is not a feasible alternative to HNP license renewal.

Geothermal

As illustrated by GEIS Figure 8.4, geothermal plants might be located in the western continental United States, Alaska, and Hawaii where hydrothermal reservoirs are prevalent, but would not be a feasible alternative to HNP license renewal in Georgia.

Wood Energy

The pulp, paper, and paperboard industries, which consume large quantities of electricity, are the largest consumers of wood and wood waste for energy, benefiting from use of waste materials that could otherwise represent a disposal problem. In 1995, processing of wood products in Georgia generated 478 million cubic feet of wood and bark residues. Approximately 48 percent, or 230 million cubic feet, of the residue was used as industrial fuel (Reference 11). The 90 trillion BTU of energy[25] estimated to be available annually from Georgia forests would only produce the amount of electricity that HNP produces in 7 hours.[26] Due to uncertainties associated with obtaining sufficient wood and wood waste to fuel a baseload generating facility, SNC has determined that wood waste is not a feasible alternative to renewing the HNP license. In addition, ecological impacts of large-scale timber cutting (e.g., soil erosion and loss of wildlife habitat) make this alternative less acceptable.

Municipal Solid Waste

The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to land-filling rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics, particularly with electricity prices declining (Reference 28). SNC has determined that municipal solid waste would not be a feasible alternative to HNP license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol, and gasifying energy crops (including wood waste). None of these technologies has

25. Calculated as follows: 1 cubic foot of wood = 187,500 BTU (Reference 11). Therefore, 478,000,000 cubic feet of wood × 187,500 BTU per cubic foot of wood = 89,625,000,000,000 (90 trillion) BTU.
26. At an average of 10,000 BTUs per kilowatt-hour (kWh), 90 trillion BTUs would yield 9.0 million kWh per year. In 1997, HNP generated slightly more than 12,000 million kWh (Reference 19) or about 1.3 million kWh per hour.

progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant such as HNP (ethanol is primarily used as a gasoline additive for automotive fuel). For these reasons, SNC has determined that such fuels do not offer a feasible alternative to HNP license renewal.

Oil

GPC has 6 oil-fired units. It has been GPC's experience that the cost of oil-fired operation is about 6 times that of nuclear operation and 2 times that of coal-fired operation (Reference 12). In addition, increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation (Reference 28). For these reasons, SNC has determined that oil-fired generation is not a feasible alternative to HNP license renewal.

Nuclear Power

Work on advanced reactor designs has continued and nuclear plant construction continues overseas. However, the cost of building a new nuclear plant and the political uncertainties that have historically surrounded many nuclear plant construction projects are among the factors that have led energy forecasters such as the Energy Information Administration to predict no new domestic nuclear power plant orders for the duration of current forecasts - through the year 2020 generation (Reference 28). Therefore, SNC concludes that new nuclear plant construction is not a feasible alternative to HNP license renewal.

Delayed Retirement

HNP provides approximately 12,000,000 megawatt-hours of GPC's generating capacity and approximately 14 percent of its energy requirements (Reference 12). As a subsidiary of Southern Company, GPC supplies electrical power to the Southern Company regional electric grid (which includes Savannah Electric, Alabama Power, Gulf Power, and Mississippi Power). Southern Company expects the demand on its regional grid to increase approximately 2 percent (700 MW per year) including reserve capacity through the year 2018. In its planning, SNC considered the delayed retirement of older, less-efficient baseload plants. However, the cost of refurbishing these plants to make them more efficient and meet future emission limits would exceed the cost of building new plants. For this reason, SNC has determined that delayed retirement of other Southern Company generating units would not be a feasible alternative to HNP license renewal.

Conservation

GPC has developed residential, commercial, and industrial programs to reduce both peak demands and daily energy consumption (demand-side management). Program components include the following:

- Peak clipping programs – Include energy saver switches for air conditioners, heat pumps, and water heaters, allowing GPC to interrupt electrical service to reduce load during periods of peak demand; dispersed generation, giving GPC dispatch control over customer backup generation resources; and curtailable service, allowing GPC to reduce customers' load during periods of peak demand.

- Load shifting programs – Use time-of-use rates to encourage shifting loads from on-peak to off-peak periods. Use of computerized real time displays allowing the customer to monitor power usage and to keep power usage below peak thresholds while maintaining optimal product production.

- Conservation programs – Promote use of high-efficiency heating, ventilating, and air conditioning; encouraging construction of energy-efficient homes and commercial buildings; improving energy efficiency in existing homes; providing incentives for use of energy-efficient lighting, motors, and compressors.

The GPC demand-side management program currently produces an estimated annual peak demand generation reduction of about 885 MWe. The GPC load growth projection anticipates a demand-side management savings of about 1,120 MWe in 2016. Because these savings are part of the long-range plan for meeting projected demand, it is not available as an "offset" for HNP, and Southern Company does not foresee availability of another 1,690 MWe (HNP capacity). For these reasons, SNC has determined that demand-side management is not a feasible alternative to renewing the HNP license.

2.3 SUMMARY COMPARISON

Table 2-4 summarizes the proposed action, feasible alternatives, and the environmental impacts that differentiate the proposed action from the alternatives. The primary differences would be impacts to air, land use, terrestrial resources, and aesthetics.

- Air Impacts – Coal- and gas-fired generation alternatives would introduce large and moderate air impacts, respectively, due to emission of pollutants such as nitrogen oxides, sulfur oxides, carbon oxides, and particulate emissions that would not occur if NRC renewed the HNP license. SNC assumes that the power purchase alternative could result in generator construction somewhere, which would introduce the same type of air impacts. These impacts are of concern due to their association with the issues of human health, regional acid rain, and global climatic change.

- Land Use Impacts – Both coal- and gas-fired alternatives would introduce some new land use impacts due to the need to convert predominantly forested land to industrial use. The coal-fired alternative would have the largest impact due to its need for ash and scrubber sludge disposal acreage that, in turn, would introduce a risk of groundwater contamination.

- Terrestrial Resource Impact – Both coal- and gas-fired generating alternatives would produce moderate to large ecological impacts to terrestrial resources as a result of the conversion of substantial forested acreage to industrial use. Impacts in either case would include wildlife habitat loss and reduced biological productivity, and could, depending on the location of new facilities, include habitat fragmentation and a localized reduction in biological diversity.

- Aesthetic Impacts – HNP's main generating facilities (including reactor buildings, turbine buildings, and control building) are relatively unobtrusive, neutral-colored buildings, but are visible from portions of U.S. Highway 1 and from the adjacent reach of the Altamaha River. The coal-fired alternative would require the construction of a number of large structures, including three 600-foot stacks that would be visible for approximately 4 miles in summer months and 10 miles in winter. The coal-fired alternative would introduce a moderate aesthetic impact that would also be associated with coal-fired generation sources under the imported electrical power alternative.

Impacts to other resources (e.g., surface water, groundwater, socioeconomics, and cultural resources) would be similar in magnitude regardless of the generation alternative employed and would not be obvious discriminators.

A number of environmental impacts have been assigned a significance level of "small" by NRC in the GEIS. SNC has identified no new or significant information that would make these conclusions inapplicable to HNP. In compliance with NRC regulations, Chapter 3 discusses other environmental effects and concludes that they would be of small significance. Chapter 3 also discusses the environmental effects of the alternatives.

Table 2-1. Weekly discharge temperatures, Edwin I. Hatch Nuclear Plant, 1997-1998.

Month/Year		Unit 1 Average discharge temperature (°F)	Unit 1 Maximum discharge temperature (°F)	Unit 2 Average discharge temperature (°F)	Unit 2 Maximum discharge temperature (°F)
January	1997	63.0	68.0	63.8	67.0
February	1997	68.8	71.0	66.0	68.0
March	1997	71.6	79.0	70.0	80.0
April	1997	77.5	82.0	76.0	84.0
May	1997	78.3	85.0	78.3	86.0
June	1997	82.2	86.0	83.0	86.0
July	1997	88.0	91.0	87.5	90.0
August	1997	84.3	86.0	88.0	93.0
September	1997	84.6	88.0	86.6	86.6
October	1997	76.5	84.0	77.5	77.5
November	1997	62.3	68.0	62.0	62.0
December	1997	67.6	75.0	68.4	73.0
January	1998	61.8	69.0	62.7	69.0
February	1998	67.8	77.0	67.8	77.0
March	1998	71.4	77.0	71.0	77.0
April	1998	74.5	75.0	74.5	75.0
May	1998	83.8	89.0	81.8	86.0
June	1998	87.0	91.0	87.6	91.0
July	1998	89.8	92.0	90.3	92.0
August	1998	90.0	94.0	90.4	94.0
September	1998	87.5	89.0	85.0	91.0

Source: Reference 6.

Table 2-2. HNP surface water use.

Year	Average Daily Withdrawal (MGD)[a]	Maximum Daily Withdrawal (MGD)[a]	Average Daily Loss From Evaporation (MGD)[b]
1989	55.48	70.43	31.62
1990	56.88	80.50	32.42
1991	56.94	81.40	32.46
1992	58.02	82.73	33.07
1993	58.74	85.31	33.48
1994	57.30	83.61	32.66
1995	59.29	78.23	33.80
1996	57.07	78.03	32.53
1997	54.93	75.02	31.31
Average	57.18		32.59

MGD = million gallons per day.
a. Source: Reference 29.
b. Calculated based on an assumed consumptive loss of 57 percent (Section 2.1.4).

Table 2-3. HNP groundwater use (units: thousands of gallons, unless otherwise specified).[a,b]

Month	1990	1991	1992	1993	1994	1995	1996	1997
January	5,206.9	5,410.3	10,542.9	10,217.0	5,248.5	5,057.7	6,185.3	5,309.0
February	4,655.2	4,700.6	7,102.8	10,038.0	4,586.7	5,113.1	4,966.3	4,552.0
March	4,894.1	6,145.4	7,804.6	5,420.3	5,835.8	4,969.6	5,537.1	5,713.0
April	5,219.8	6,205.0	5,662.2	5,050.3	5,872.3	4,828.8	5,010.4	4,811.0
May	5,790.6	5,646.7	5,310.4	4,705.0	5,377.1	4,861.2	5,022.5	5,114.0
June	5,627.7	5,122.1	4,589.9	4,355.8	4,376.9	4,467.0	4,566.6	4,495.0
July	5,860.0	5,052.3	5,618.3	4,992.3	4,801.1	5,115.6	4,945.9	4,848.1
August	5,118.5	5,846.6	5,522.2	7,335.3	4,884.0	4,561.3	4,992.2	5,369.4
September	5,592.4	7,385.3	5,272.0	4,866.9	5,375.8	4,942.7	4,856.8	5,198.3
October	5,940.6	9,594.6	4,545.0	4,976.8	5,501.4	6,758.4	5,746.3	5,866.5
November	4,472.4	8,548.8	4,375.5	4,795.7	4,581.0	5,037.7	6,247.3	4,927.0
December	4,536.3	8,389.5	6,218.0	5,333.8	5,024.6	5,760.0	4,822.4	6,345.5
Yearly Total	64,904.5	80,038.2	74,555.8	74,080.2	63,459.2	63,468.1	64,895.1	64,545.8
Average pumping rate (gpm)	120	149	130	137	117	118	120	119

gpm = gallons per minute.
a. Source: Modified from Reference 30.
b. Represents total for site well numbers 1, 2, and 3.

Table 2-4. Comparison of alternatives for license renewal of the Edwin I. Hatch Nuclear Plant (Page 1 of 2).[a]

Resource	Proposed Action	Alternative 1 – Coal-Fired	Alternative 2 – Gas-Fired	Alternative 3 – Import
Description	HNP license renewal for 20 years No additional workers; bounding analysis assumes 60 additional full-time employees above existing site workforce (950)	New construction on Hatch site Three 600-MWe (ISO rating), tangentionally-fired, dry-bottom units Pulverized bituminous coal, 13,000 Btu/lb, 10% ash, 0.8% sulfur Low nitrogen burners, overfire air, selective catalytic reduction (95% NO_x reduction efficiency) Wet lime/limestone flue gas desulfurization system (95% removal efficiency) Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency) Daily train delivery of 15,500 tons of coal and 880 tons of lime/limestone Average 1,500 construction workforce (peak 2,000) for 3 years, 250 permanent workers	New construction on Hatch site Four 440-MWe (ISO rating) combined units Natural gas, 1,000Btu/scf, 10 million ft^3/hr Backup low sulfur No. 2 fuel oil Fry, low nitrogen burners, selective catalytic reduction with water injection for backup oil firing Average 500 construction workers (750 peak), 125 permanent workers	Imported electric power (purchase) Could involve new construction of generation and transmission capacity
Resource impacts				
Air	Small, Category 1	Large – 3,600 tons SO_x/year; 1,710 tons NO_x/year; 240 tons filterable particulates/year; and 54 tons PM_{10}/year; 1,170 tons CO/year.	Moderate – 386 tons of NO_x/year.	Small to Large – Depends on technology used to generate power.
Aesthetics	Small - Category 1	Moderate – 3 new, 200-foot power plant structures and 600-foot stacks potentially visible for 4 to 10 miles in the summer and winter, respectively. Noise from trains and coal-handling equipment.	Small – New 100-foot turbine building, 230-foot exhaust stack.	Small to Large – For new construction, impacts could be similar to Alternative 1 depending on location.
Aquatic ecology	Small - operational history demonstrates small impacts	Small – Impacts would not exceed proposed action.	Small – Impacts would be less than proposed action.	Small to Large – New construction could cause habitat loss due to conversion to industrial use depending on location.

Table 2-4. Comparison of alternatives for license renewal of the Edwin I. Hatch Nuclear Plant (Page 2 of 2).[a]

Resource	Proposed Action	Alternative 1 – Coal-Fired	Alternative 2 – Gas-Fired	Alternative 3 – Import
Groundwater	Small - Withdrawal 130 gpm Operational history demonstrates small impacts	Small – Withdrawal of 6.1 gallons per minute for potable water use.	Small – Impacts would be less than proposed action.	Small to Large – New construction could add new source of groundwater withdrawal depending on location.
Land	Small - Land use changes due to license renewal not likely	Moderate – 300 acres for power block construction and coal pile; 600 acres for waste (ash and scrubber disposal).	Moderate – 500 acres for power block construction; 121 acres for pipeline construction.	Small to Large – New construction could convert existing land use to power generation.
Socioeconomic	Small – Changes due to license renewal not likely Bounding analysis indicates 9% decrease in housing availability; loss of less than 0.5% of the available local water supply system capacity; no anticipated impacts to transportation system and education system	Moderate – Temporary increase in impacts during 3-year construction period from 1,500 workers, then impact of loss of tax and employment base due to reduction in HNP workforce from 950 to 220. Small impact to transportation resources due to 4 interruption per day from trains, 5 minutes each, on 2 highways.	Moderate – Temporary increase during 3-year construction period of 500 workers, then impact of loss of tax and employment base due to reduction of size of HNP workforce from 950 to 125.	Small to Large – New construction could introduce worker population impacts on housing and public services depending on location and technology.
Terrestrial ecology	Small – Changes due to license renewal not likely	Moderate – Loss of habitat from construction in forested areas.	Moderate – Loss of habitat from construction in forested areas	Small to Large – New construction could involve loss of habitat due to conversion to industrial use depending on location.
Waste management	Small – Category 1	Moderate – 1.5 million tons of ash and scrubber sludge a year.	Small – Due to little combustion or pollution control byproducts	Small to Large – Depends on technology.

CO = carbon monoxide.
ft^3 = cubic feet.
lb = pound.
NO_x = nitrogen oxides.
scf = standard cubic foot.
SO_x = Sulfur oxides.

a. Category 1 = License renewal environmental issue that NRC has defined as small for all plants (10 CFR Part 51 Subpart A, Attachment B, Table B-1, Footnotes 2 and 3).

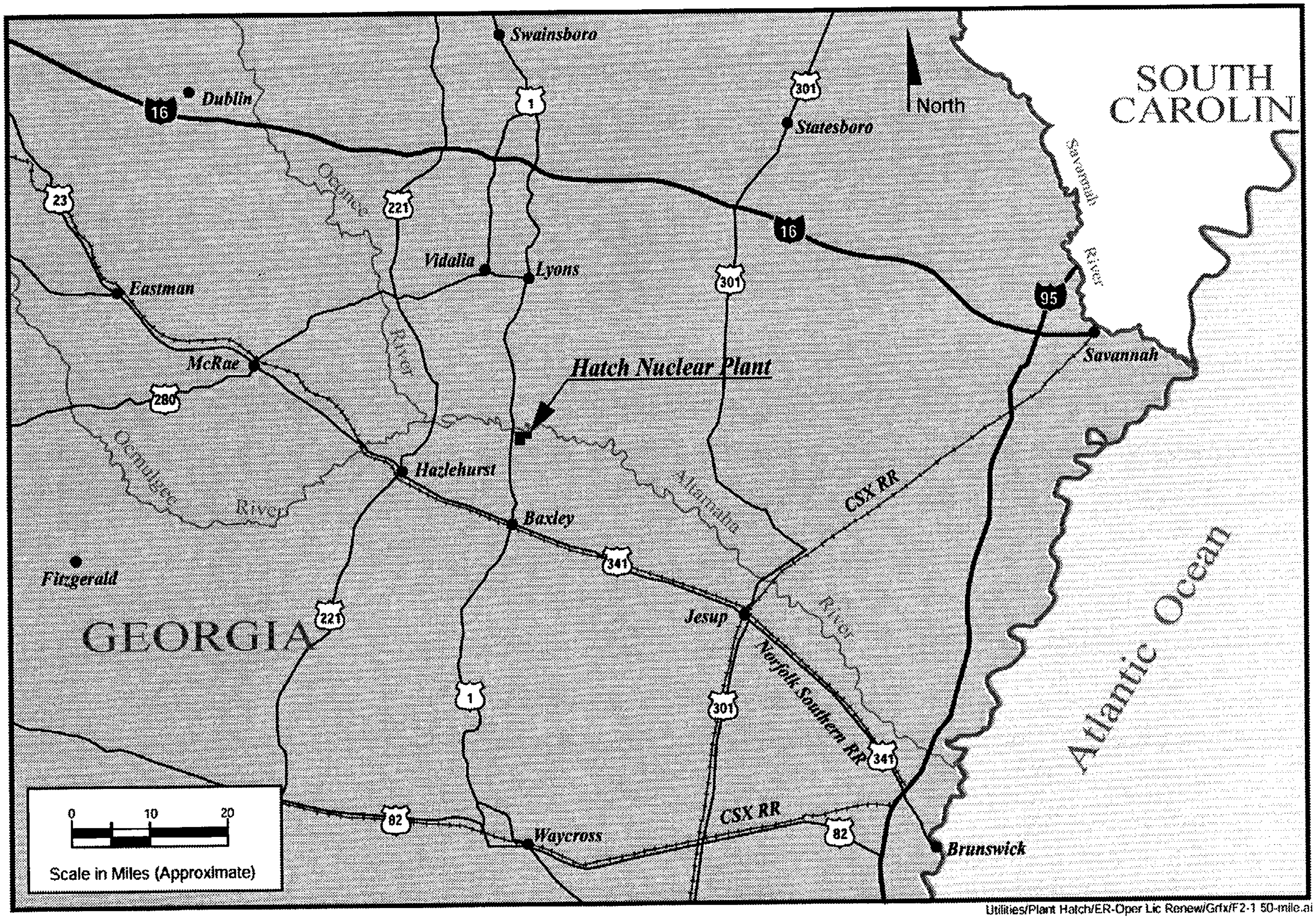


Figure 2-1. Edwin I. Hatch Nuclear Plant, 50-mile region.

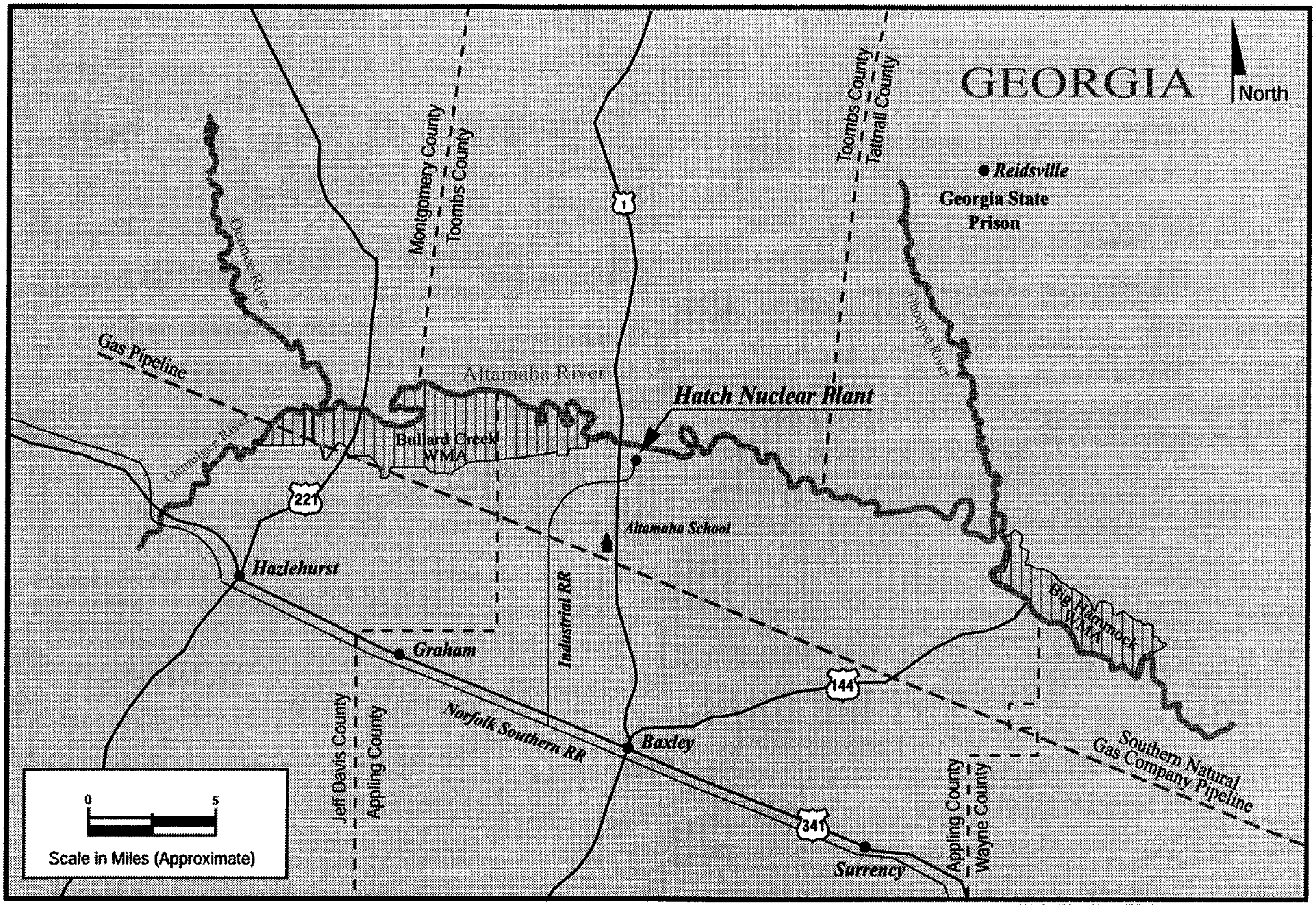


Figure 2-2. Edwin I. Hatch Nuclear Plant, 10-mile region.

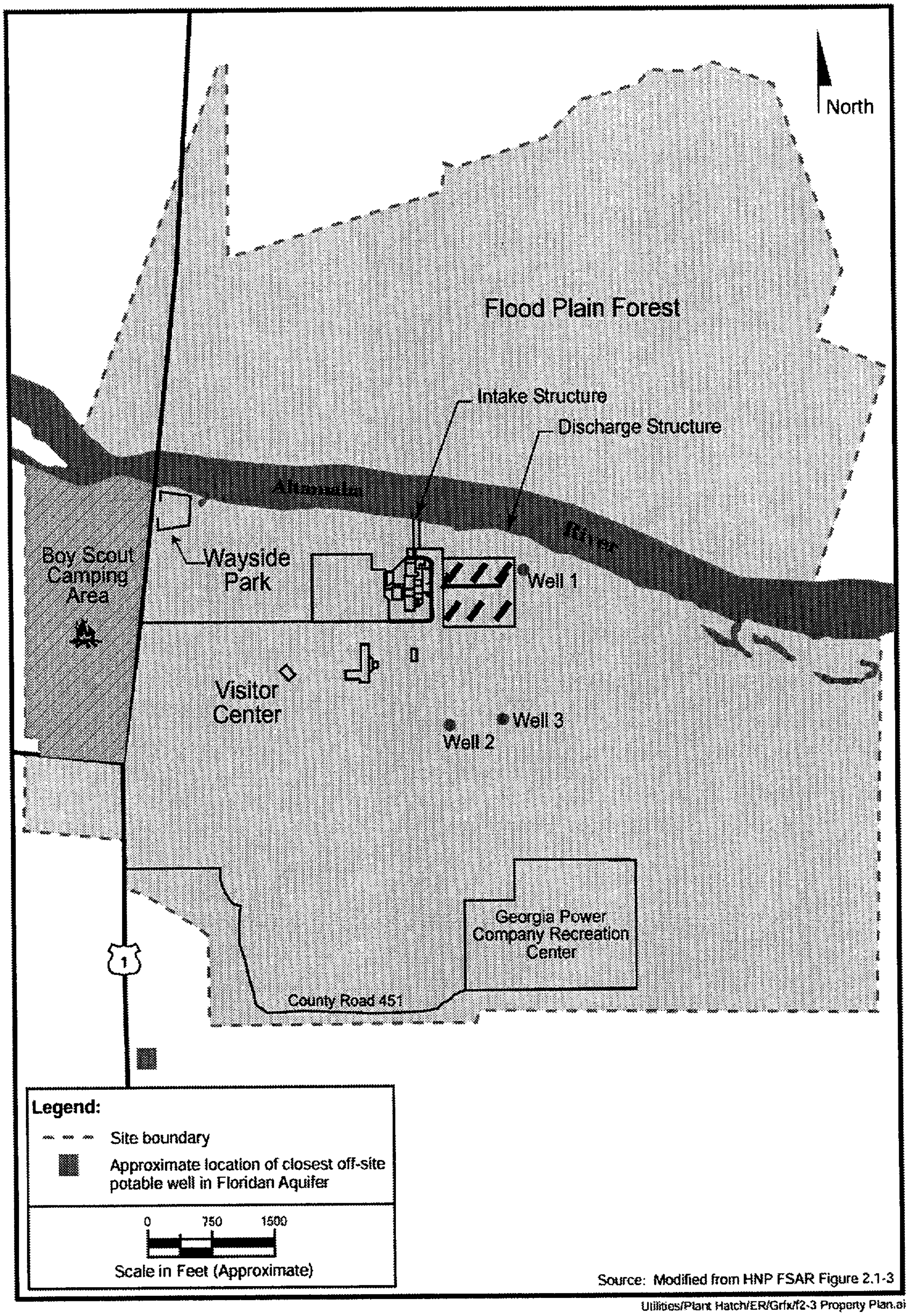


Figure 2-3. Edwin I. Hatch Nuclear Plant property plan

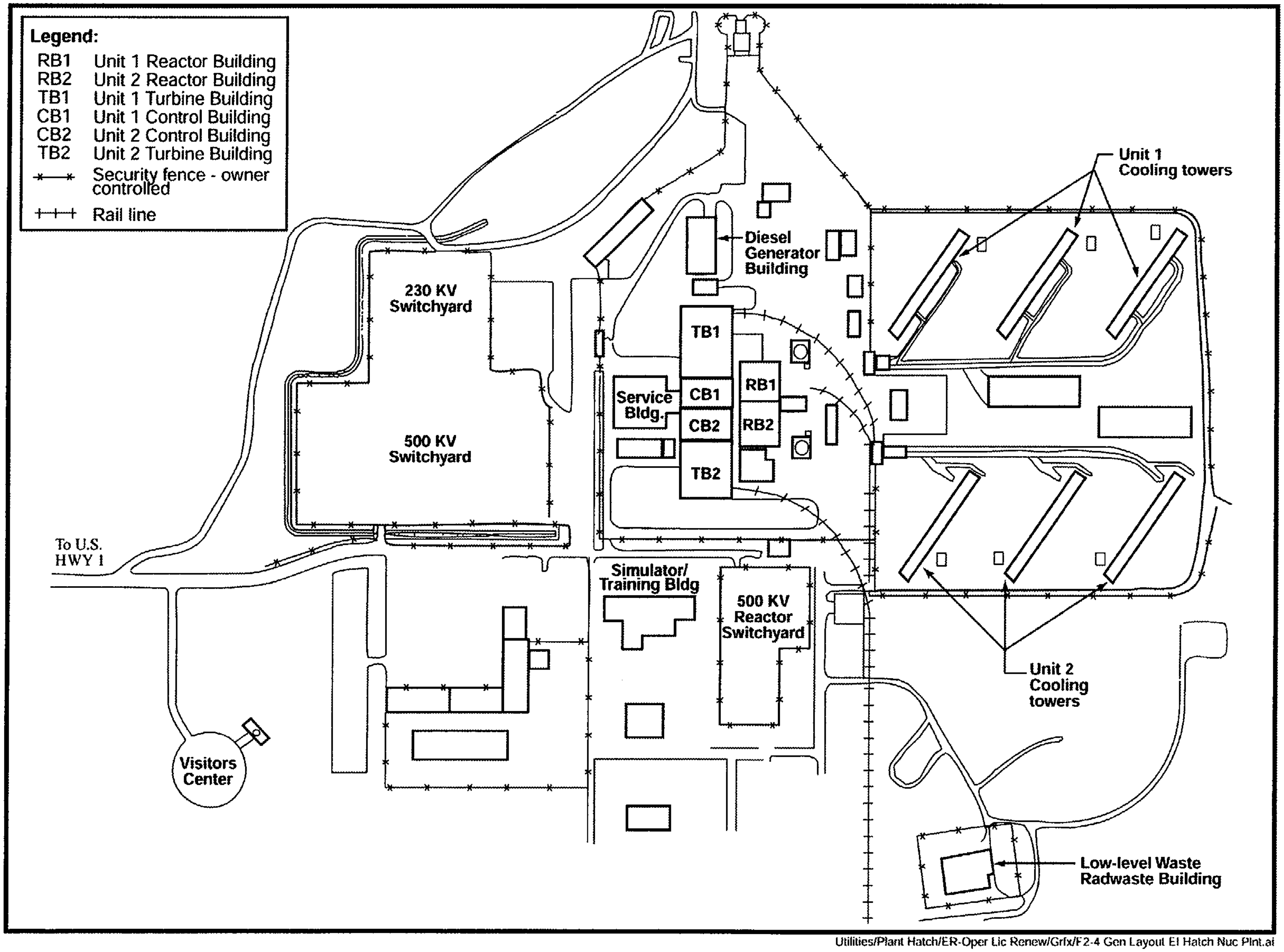


Figure 2-4. Edwin I. Hatch Nuclear Plant site plan.

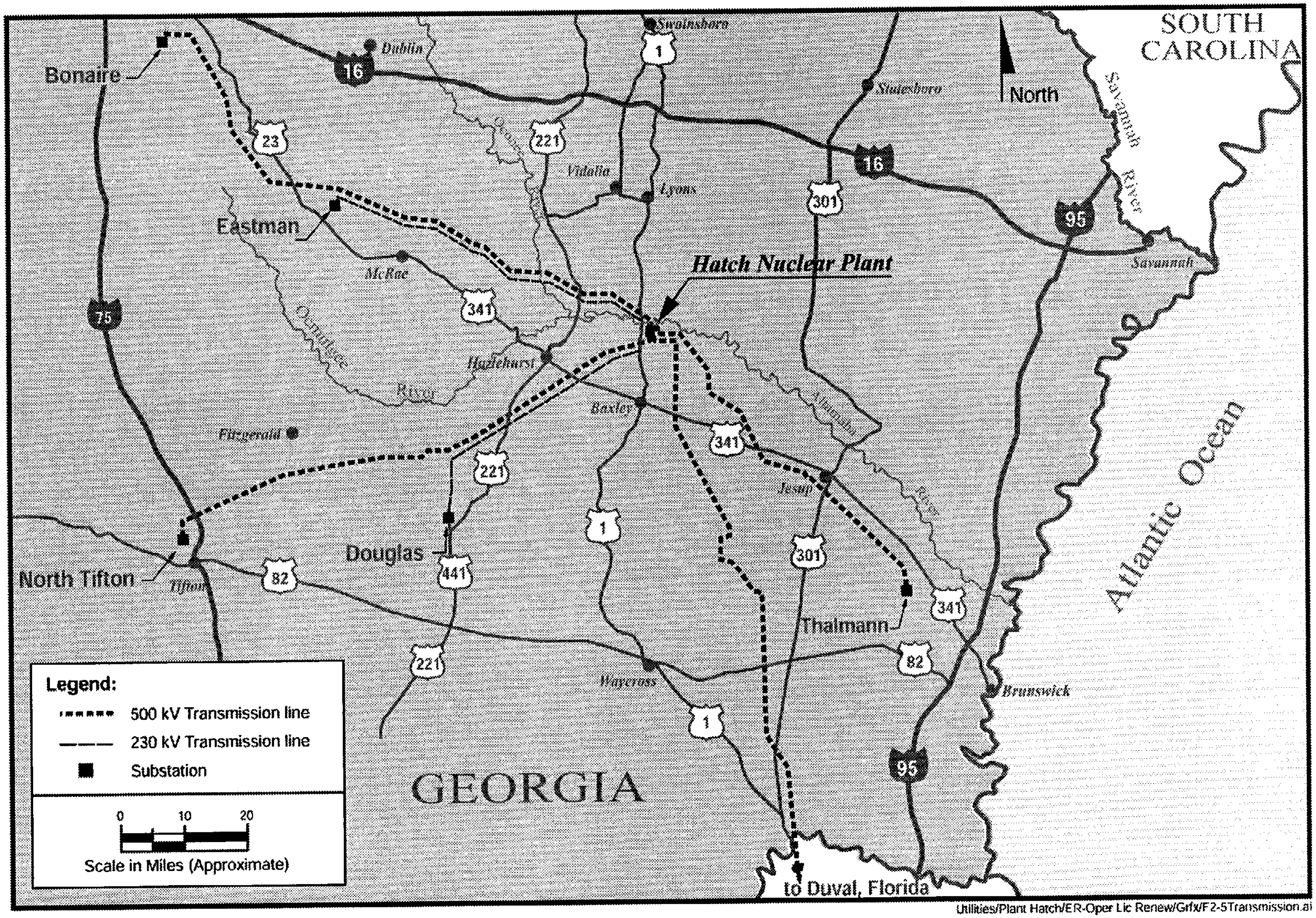


Figure 2-5. Edwin I. Hatch Nuclear Plant transmission lines.

3.0 ENVIRONMENTAL CONSEQUENCES AND MITIGATING ACTIONS

3.1 PROPOSED ACTION

The proposed action is the renewal of existing NRC licenses for Edwin I. Hatch Nuclear Plant Units 1 and 2.

3.1.1 Introduction

Section 3.1 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of Edwin I. Hatch Nuclear Plant's (HNP's) operating license. The scope of this assessment is guided by the U.S. Nuclear Regulatory Commission's (NRC's) generic analysis presented in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (Reference 10). Through this analysis, NRC identified 92 environmental issues associated with the action of license renewal. These issues were categorized as Category 1 if the following criteria were met:

- 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 characteristic.
- A single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective offsite radiological impacts from the fuel cycle and from high-level-waste and spent-fuel disposal).
- 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.

If the GEIS analysis concluded that one or more of the criteria of Category 1 could not be met, the issue was designated as a Category 2 issue and additional plant-specific review is required to be submitted by the applicant. These issues were listed with assigned categorization in Table B-1 of Appendix B to Subpart A of Part 51. This table has been reproduced and included in Attachment A of this report. For ease of reference, the issues have been numbered by the order in which they are listed in the regulation. Attachment A also provides a cross-reference to the section in this environmental report where each issue applicable to HNP is discussed and provides justification for those issues determined not to be applicable to HNP.

3.1.1.1 Category 1 License Renewal Issues

NRC

The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part. [10 CFR 51.53(c)(3)(i)]

. . . absent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal . . . . (Discussion of Regulatory Requirements, 61 FR 109, June 5, 1996, pg. 28483)

NRC categorized 69 of the environmental issues related to the license renewal of nuclear power plants as Category 1 issues. Southern Nuclear Operating Company (SNC) having reviewed all Category 1 issues for new and significant information adopts by reference the conclusions of Table B-1 of Appendix B to Subpart A of Part 51 and the GEIS analysis for all Category 1 issues applicable to HNP. Therefore, Section 3 will not include discussion of Category 1 issues.

As discussed in Section 3.1.17, a SNC review of Category 1 issues determined that the conclusions of the GEIS remained valid with respect to Plant Hatch and uncovered no new and significant information regarding the HNP environment or HNP operations.

3.1.1.2 Category 2 License Renewal Issues

NRC

The environmental report must contain analyses 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 issues in Appendix B to subpart A of this part. [10 CFR 51.53(c)(3)(ii)]

The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues . . . . [10 CFR 51.53(c)(3)(iii)]

NRC categorized 21 environmental issues as Category 2. Based on the characteristics of the HNP site and physical features of the Plant, only those Category 2 issues applicable to HNP will be analyzed in this section. There are five Category 2 issues that do not apply to HNP. These issues and the basis for exclusion are:

Issue	Basis for Exclusion
25. Entrainment of fish and shellfish in early life stages	Not applicable because HNP does not use a once-through heat dissipation system.
26. Impingement of fish and shellfish	Not applicable because HNP does not use a once-through heat dissipation system.
27. Heat shock	Not applicable because HNP does not use a once-through heat dissipation system.
35. Groundwater use conflicts (Ranney wells)	Not applicable because HNP does not use Ranney wells.
39. Groundwater quality degradation (cooling ponds at inland sites)	Not applicable because HNP does not use a cooling pond heat dissipation system.

For each Category 2 issue discussed in the following sections, SNC will state the issue, provide the reason NRC did not conclude it was a Category 1 issue, and explain in the impact analysis how that reason applies to HNP. SNC will complete the analysis by identifying the significance of the impacts relative to HNP and discuss potential mitigative alternatives when applicable and to the extent required. The significance of the impacts associated with each issue will be identified as either small, moderate, or large consistent with NRC's standard of significance established in the GEIS as follows:

- 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 any important attribute of the resource.
- Large – Environmental effects are clearly noticeable and are sufficient to destabilize any important attribute of the resource.

3.1.2 Surface Water Use

3.1.2.1 Impacts to Ecological Communities

NRC

If the applicant's plant uses cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than $3.15 \times 10^{12} ft^3$/year ($9 \times 10^{10} m^3$/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. [10 CFR 51.53(c)(3)(ii)(A)]

This 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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 13)]

The NRC made surface water use conflicts a Category 2 issue because consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants (Limerick and Palo Verde) and may be a problem in the future at other plants. In the GEIS, NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers (GEIS Section 4.3.2.1). Information to be ascertained includes: (1) Altamaha River flow characteristics, (2) HNP surface water withdrawals, (3) competing water users, and (4) impact of HNP surface water withdrawals on instream and riparian communities.

The Altamaha River is located in southeastern Georgia and drains an area of approximately 11,600 square miles. It is formed by the confluence of the Ocmulgee and Oconee Rivers about 20 miles upstream from HNP and ultimately discharges into the Atlantic Ocean just south of Darien, Georgia, approximately 117 river miles below HNP. The U.S. Geological Survey maintains a gauging station (Number 02225000) on the right bank of the River 400 feet downstream from the U.S. Highway 1 bridge, approximately 0.1 mile upstream from HNP. Attachment B presents river-flow data for this location. Based on 49 years of record, the average annual flow rate at this station is 11,580 cubic feet per second or 3.65×10^{11} cubic feet per year (see Attachment B, Equation B.1 for calculation of annual flow rate). Highest monthly flows normally occur in March and lowest monthly flows normally occur in September. The historical single day low flow is 1,620 cubic feet per second. Because the average annual flow rate is less than 3.15×10^{12} cubic feet per year, Issue 13 is applicable to HNP and an analysis is provided below.

Presently there are no other competing industrial consumptive users of water from the Altamaha River in the vicinity of HNP, nor are there plans for any new major consumptive users in the foreseeable future. There are no water quality issues with the river in the vicinity of HNP and no restrictions have been imposed on HNP during low flow periods.

Section 2.1.4 describes HNP surface water withdrawals. For the period of 1989 through 1997, HNP withdrew an annual average of approximately 57 million gallons per day from the Altamaha River for cooling. Through the evaporative cooling process, water vapor is lost to the atmosphere ("consumed"), thus the volume of water returned to the river (approximately 25 million gallons per day) is less than the volume withdrawn. Therefore, the average HNP surface water consumption rate is approximately 32.6 MGD. When compared to the average river discharge as measured at gauging station 02225000, the consumptive loss represents 0.44 percent of river flow (Equation B.2). During minimum river discharge periods, the consumptive loss amounts to 3.1 percent (Equation B.3).

The impact of consumptive loss on the downstream riparian communities is associated with the small difference it causes in the river surface elevation. SNC has calculated the reduction in surface water elevation resulting from HNP withdrawals. These calculations are provided in Attachment B. During periods of average river discharge, consumptive loss amounts to about a 0.03 feet decrease (Equation B.4) in the downstream surface elevation. During periods of minimum river discharge, consumptive loss amounts to a lowering of the downstream surface elevation by approximately 0.08 feet (Equation B.5).

The shoreline of the Altamaha River in the vicinity of HNP and immediately downstream for several miles is characterized by steep bluffs, floodplain forests, and sandbars. Based on average daily flows for a 1-month period over the last 22 years, the riparian communities experience an average annual surface elevation fluctuation of approximately nine feet. The consumptive loss incurred by plant operations has the greatest effect on surface elevation during low flow periods. The duration of low-flow conditions is approximately 2-3 months. The shoreline exposed during these periods is under water during the other 9 to 10 months of the year. Vegetation is found at elevations that are not flooded for most of the year by the river. When the river stage is high enough to flood the riparian communities, the impact of consumptive loss from plant operations is negligible.

Consumptive loss from plant operations during the low flow periods would have the greatest impact on instream biological communities (e.g., mussels and fish) if it occurred during the spawning season. If, for example, a reduction in flow (or river level) were enough to hinder up- or downstream movement of anadromous fish or the movement of resident fish into shallow sloughs and oxbows to spawn there could be a reduction in spawning success. The spawning season for fish in the Altamaha River occurs in the spring and early summer, the period of highest flows in the Altamaha (Attachment B). Since the lowest average daily flow for a 1-month period occurs in September, and the highest average daily flow for a one month period occurs in March, consumptive loss from plant operations is not expected to have any impact on instream communities.

Freshwater mussels vary in their ability to withstand emersion (exposure to air). Some species are adapted to withstand prolonged periods of emersion, while others are emersion-intolerant (Reference 59). Mussels move over and through the substrate by means of a protrusible muscular foot. Some species are known to move several feet per hour in response to stagnant conditions or falling water levels (Reference 60). Other species respond to falling water levels by burrowing more deeply into the substrate, seeking moisture. However, most riverine species have evolved under seasonally-fluctuating water-level conditions and are unaffected by small fluctuations in water level. Under worst-case conditions, consumptive losses would result in a one-inch lowering of water level downstream of HNP. Any impacts to resident mussel communities would be "small" to insignificant.

Based on the analysis presented above, SNC concludes that the appropriate characterization of HNP impacts on ecological communities due to consumptive cooling would be "small." On October 13, 1999 GADNR Wildlife Resource Division provided their concurrence with this conclusion (Attachment C). The impacts would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource. Because

SNC and the state have not identified any impacts, SNC also concludes that mitigation is unwarranted.

3.1.2.2 Impacts to alluvial aquifer

> **NRC**
>
> ***If the applicant's plant uses 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)...The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow. [10 CFR 51.53(c)(3)(ii)(A)]***
>
> ***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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 34)]***

The NRC made this a Category 2 issue because the significance of the indirect groundwater use conflict resulting from surface water withdrawals could not be determined without site-specific information (GEIS Section 4.8.1.3). Information to be ascertained includes: (1) Altamaha River flow characteristics, (2) HNP surface water withdrawals, and (3) impacts to alluvial aquifer recharge.

A description of the Altamaha River including flow characteristics is provided in Section 3.1.2.1. Since the average flow (3.65 × 10^{11} cubic feet per year) is less than NRC's threshold criteria, an analysis of surface water withdrawals on the alluvial aquifer recharge is provided.

The alluvial aquifer at the site is primarily south of the River within the facility boundary, and consists of approximately 55 feet of poorly-sorted sand, gravel, and clay. The alluvial aquifer contains groundwater under water table conditions. Clayey soils dominate in the upper portion of the aquifer. Recharge to the aquifer is mainly through the infiltration of local precipitation. Recharge is also provided in a limited amount by discharge from the Altamaha River during high stages and by the minor confined aquifer of the Hawthorn Formation, to which the alluvium is hydraulically connected. Groundwater typically discharges to the Altamaha River. Although no aquifer data exist for the unit, the alluvium in the region is considered to be a large potential source of water.

Based on the information given in Section 3.1.2.1, the consumptive use by the facility was expected to lower the river by 0.08 feet during periods of minimum river discharge. During periods of average river discharge, consumptive losses amount to a 0.03 feet decrease in the downstream surface elevation. This small change in the level of the river would not appreciably alter the gradient of the groundwater flowing from the alluvial aquifer to the river.

Therefore, SNC has concluded that surface water withdrawal impacts to the alluvial aquifer recharge (Issue 34) is small. The impacts would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the resource, and therefore, would not warrant mitigation.

3.1.3 Groundwater Use

> **NRC**
>
> ***If the applicant's plant . . . 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. [10 CFR 51.53(c)(3)(ii)(C)]***
>
> ***Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 33)]***

The NRC made this a Category 2 issue because it could not assign a single significance level (small, moderate, or large), and because, if there were moderate or large impacts, mitigation might be warranted. The effect of groundwater use on neighboring groundwater users would depend on the rate of withdrawal and the distance to the neighboring well (GEIS Section 4.8.1.1). Therefore, information to be ascertained includes: (1) HNP groundwater withdrawal rate (whether greater than 100 gallons per minute); (2) distance to neighboring well(s); and (3) impact on the neighboring well(s).

As described in Section 2.1.5, HNP withdraws an average of 126 gallons per minute, making this issue applicable to HNP. The following discussion describes the site geohydrology and local groundwater use and provides a discussion of the potential impacts to offsite users as a result of continued operations.

Geology and groundwater hydrology are described in Sections 2.4 and 2.5 of the Final Safety Analysis Report for HNP Unit 2 (Reference 32) and are summarized below. The HNP site lies within the Coastal Plain physiographic province and is underlain by approximately 4,000 feet of relatively unconsolidated Mesozoic and Cenozoic sand, gravel, clay, marl, claystone, sandstone, and limestone. These strata overlying basaltic basement rock of pre-Cretaceous age, and dip and thicken seaward. There was no evidence of faulting during the exploratory drilling and construction of the facility. The formations of interest at the site, due to their water bearing characteristics, consist of the alluvium beneath the Altamaha River floodplain, the Brandywine Formation (the perched aquifer), the Hawthorn Formation, the Tampa Formation, the Suwanee Formation, the Ocala formation, and the Lisbon Formation. The Brandywine Formation caps the upland areas adjacent to the stream drainage areas. These formations and the aquifers they comprise are described in Table 3-1.

The alluvial aquifer is described in Section 3.1.2.2. The perched water aquifer at the site (Brandywine) is approximately 10 feet thick. This aquifer is recharged through direct precipitation. A few springs exist approximately 1.5 miles southwest of the Site at the base of the Brandywine. Discharge is to the ground surface or to streams that have cut through the confining layer at the base of the formation. These springs are dry during droughts. No permeability or safe-yield data are available for this unit.

The water table in the unconfined aquifer is the surficial unit south of the Altamaha River. This aquifer unit is 45 to 50 feet thick and yields less than 10 gallons per minute. The water table reflects the topography of the Site area. High water levels underlie the surrounding hills and low water levels are near valleys. The flow direction beneath the plant site is north and east toward the Altamaha River floodplain, along gradients ranging from 14 to 80 feet per mile. High-clay-content soils near the top of the aquifer and at ground surface locally form a discontinuous, relatively impermeable zone. Recharge to the unconfined aquifer is by the infiltration of precipitation through and around the leaky clay zones.

The minor confined aquifer is recharged locally in the southwest portion of the Site where the middle portion of the Hawthorn is exposed. Natural discharge of the aquifer takes place where the aquifer comes into contact with the alluvium of the Altamaha River. Permeability of the aquifer increases with depth. The potentiometric surface of the aquifer has a gradient of 23 feet per mile to the north, toward the Altamaha River. The aquifer unit is approximately 65 feet thick and can yield up to 10 gallons per day. A confining unit separates the minor confined aquifer from the underlying aquifer.

The principal artesian aquifer (Floridan) beneath the Site, and the aquifer of major interest, is approximately 1,000 feet thick. Recharge to the aquifer is about 60 miles northwest of the site at the outcrop area for the formations that comprise the aquifer. The potentiometric surface of the aquifer slopes gently to the southeast beneath the Site. The aquifer is isolated from the overlying aquifers by a confining unit that prevents the vertical migration of groundwater. The Floridan Aquifer also has a higher potentiometric head than the overlying aquifers. The presence of the higher potentiometric head also prevents a downward migration of groundwater.

Site Wells Number 1 and Number 2, described in Section 2.1.5, are screened to the principal artesian (Floridan) aquifer. During HNP construction, pump tests were conducted to determine the groundwater characteristics for this unit. The wells pumped for 9 hours at rates of 752 gallons per minute (Well Number 1) and 797 gallons per minute (Well Number 2). Drawdown in the wells stabilized at 5 feet in Well Number 1 and 8 feet in Well Number 2. The results of the pumping tests indicated a specific capacity of 100 to 125 gallons per day per foot of drawdown within the well (Reference 32). Based on published literature, the transmissivity in the vicinity of the Site is approximately 130,000 gallons per day per foot, and the effective permeability is 0.1 and 0.2 feet per minute (Reference 32). Data gathered during pumping tests and existing data for this aquifer indicate that a properly designed well installed within this aquifer unit can safely yield over 1,100 gallons per minute. A third site well, Well 3 was added to supply domestic water to the recreation facility. The well yield for Well 3 (less than 1,000 gallons per day) will not significantly impact the water usage of the aquifer.

Within the immediate vicinity of the Site, the primary use of groundwater is for domestic needs, with a limited amount for livestock. Most domestic wells are screened within the unconfined aquifer. The closest well to the Site boundary that is screened to the principal aquifer is located approximately 1,000 feet southwest of the Site (Figure 2-3). Currently, there is no industrial demand for groundwater within the vicinity of the Site, and no groundwater is used for irrigation. The nearest appreciable demand is 10 miles south of the Site, where the town of Baxley has applied for a permit modification dated September 1, 1997. The permit modification request is for 4 wells withdrawing approximately 850,000 gallons per day from the principal aquifer.

As described above, each of the onsite production wells is capable of producing approximately 750 gallons per minute. The pump test conducted during construction demonstrated that at this rate of pumping there was no interference between Site Wells 1 and 2. These two wells are located approximately 1,780 feet apart; therefore, the effective radius is conservatively assumed to be approximately 2,000 feet. The onsite well closest to the facility boundary is Well 1 at approximately 3,400 feet. Based on the conservative pumping rate of 750 gallons per minute and a conservative effective radius of 2,000 feet, the resulting drawdown in Well 1 would not extend to the facility boundary. Given that the actual plant groundwater requirements (126 gallons per minute) are about one fifth of that used to determine the effective radius, the drawdown of the groundwater potentiometric surface attributable to plant operations would be substantially less than that demonstrated by the original site pump test data, creating no interference with offsite wells.

The site production wells are located in the Floridan Aquifer. This aquifer unit is isolated geologically from the minor confined aquifer by a confining unit that is approximately 100 feet thick. Since monitoring began at the facility in 1969, there has been little to no fluctuation of the water level in the minor confined aquifer. Water levels in the unconfined aquifers have been observed to vary according to normal seasonal fluctuations. There have been no observed effects in the monitoring wells installed in the shallow on-site aquifers from the pumping of groundwater from the Floridan on-site wells.

Due to the high potential yields the Floridan aquifer is capable of producing and the low production yields required by HNP, the Plant will have little to no effect on the aquifer. There is some limited domestic and agricultural use of groundwater in rural areas surrounding the site, but no groundwater use conflicts have been identified. SNC has concluded that HNP groundwater-use impacts (Issue 33) would be small. The impacts would not be detectable or would be so minor that they would neither destabilize nor noticeably alter any important attribute of the groundwater resources. Given the fact that groundwater usage during the period of continued operations would not have a noticeable impact boundary in the Floridan Aquifer at the Site and would not alter offsite groundwater usage either in the Floridan or the shallower aquifers, SNC has also concluded that mitigation measures would not be warranted.

3.1.4 Terrestrial Resources

NRC

The environmental report must contain an assessment of ". . . the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats." [10 CFR 51.53(c)(3)(ii)(E)]

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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 40)]

If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant. (GEIS Section 3.6)

The NRC made impacts to terrestrial resources a Category 2 issue because the significance of ecological impacts cannot be determined without considering site-specific and project-specific details (GEIS Section 3.6). Aspects of the site and the project to be ascertained are: (1) the identification of important ecological resources; (2) the nature of refurbishment and other license-renewal-related construction activities; and (3) the extent of impacts to plant and animal habitat.

<u>HNP Site and Environs</u>

The HNP site consists of two tracts of land, an approximately 900-acre parcel north of the Altamaha River in Toombs County and a 1,340-acre parcel south of the Altamaha River in Appling County (see <u>Figure 2-3</u>). Of the 2,240 total acres that make up the site, approximately 300 acres are committed to generation facilities, parking lots, laydown areas, roads, and maintenance facilities. Approximately 350 acres are comprised of wetlands and transmission corridors. Approximately 1,600 acres are actively managed for wildlife and timber production. GPC prepared a comprehensive land management plan for HNP in 1987. The plan recommended land management practices (e.g., controlled burning and timber thinning) to enhance forest productivity while at the same time preserving the aesthetic qualities of the site and improving wildlife habitat. In 1994, in recognition of its successful natural resources management programs, HNP was awarded the Wildlife Habitat Council's Corporate Wildlife Habitat Certification.

The HNP site includes four basic ecological community types: wetlands, deciduous floodplain forests, upland areas, and pine plantations. The largest wetland area, more than 100 acres, lies just east of the generating facilities and consists of beaver ponds and blackwater sloughs with stands of cypress and blackgum. Wildlife found in wetland areas of the HNP site include amphibians (e.g., spring peeper and bullfrog), reptiles (e.g., Florida cooter and yellowbellied slider), semi-aquatic and terrestrial mammals (e.g., beaver and swamp rabbit), wading birds (e.g., great blue heron and little blue heron), and waterfowl (e.g., wood duck and mallard duck).

Deciduous floodplain forests of the HNP site include some 700 acres of blackgum, cypress, oaks, and hickories in the floodplain of the Altamaha River. The floodplain forests provide habitat for a variety of reptiles (e.g., Eastern cottonmouth "moccasin" and snapping turtle), songbirds (e.g., hermit thrush and summer tanager), birds of prey (e.g., great horned owl and barred owl), terrestrial mammals (e.g., opossum and raccoon), and semi-aquatic mammals (e.g., muskrat and river otter).

Upland areas include old fields and pine forests south and southwest of the generating facilities in various stages of succession, most of which are former agricultural lands and areas disturbed by construction activities in the 1960s and 1970s. Wildlife species characteristic of these dry upland areas include a variety of reptiles (e.g., six-lined racerunner and black racer), ground-nesting and ground-foraging birds (e.g., common bobwhite and mourning dove), and mammals (e.g., cotton rat, eastern cottontail rabbit, red fox, gray fox, and white-tailed deer). Several hundred acres of pines, including native longleaf pine, have been planted in these formerly agricultural upland areas. Georgia Power Company's goal is to re-establish the longleaf pine-wiregrass communities that were historically found in the sandhills and coastal plain of South Georgia.

Planted pines occupy roughly 400 acres of the HNP site, mostly south and southwest of the generating facilities. These pine plantations are dominated by loblolly pine, with an understory of grasses and forbs. Characteristic wildlife of these pine forests include reptiles (e.g., pine snake and gopher tortoise), songbirds (e.g., pine warbler and prairie warbler), woodpeckers (e.g., red-bellied woodpecker and yellow-shafted flicker), small mammals (e.g., fox squirrel and grey squirrel), and larger mammals (e.g., white-tailed deer).

Additional descriptions of the HNP site and its terrestrial resources may be found in the Final Environmental Statement for Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2 (Reference 4), the *Edwin I. Hatch Nuclear Plant Unit Number 2 Environmental Report* (Reference 3) and the *Final Environmental Statement Related to Operation of Edwin I. Hatch Nuclear Plant Unit 2* (Reference 5).

HNP Transmission Corridors

As noted previously in Section 2.1.6, GPC built four transmission lines to connect HNP to the transmission system. Two additional lines were added in 1981 to support an expansion of the transmission system to Florida. These six transmission lines, which occupy four transmission line corridors, provide approximately 7,200 acres of potential wildlife habitat. Approximately 340 miles of transmission corridors are associated with HNP. The standard width of the 500-kV transmission corridors is 150 feet. The 230-kV transmission corridors are 125 feet wide, while the 115-kV corridors are 100 feet wide. Where the corridors overlap, the widths can be added together minus 25 feet (e.g., a 150-foot wide corridor plus a 125-foot wide corridor minus 25 feet equals 250 feet) to approximate the overall width.

The transmission corridors pass primarily through the Coastal Plain physiographic province with the western portion of one transmission corridor (Bonaire) potentially reaching into the sandhills province. Sandy soils and flat-to-gently rolling terrain largely characterize these regions. Low hills and broad shallow valleys can be found in the more deeply dissected sandhills region. The slope, aspect, and underlying substrate of these soils play a significant role in determining the assemblage of plants and animals that are likely to occur in a given area. Because of the substantial length of the transmission corridors and the number of different directions they take from the HNP, they potentially transect a wide array of geophysical conditions that occur in the Coastal Plain of Georgia. The HNP transmission corridors pass through a number of different habitat types. Excluding those of a developed character (e.g., urban and suburban areas, agricultural areas), these habitats include pine flatwoods, pine plantations, pine-oak woodlands, longleaf pine/wiregrass communities, sandhills, floodplain/bottomland forests, swamps, marshes, seepage slopes, and abandoned (old) fields.

The Bonaire transmission corridor traverses portions of the Ocmulgee Wildlife Management Area at locations approximately eight and 10 miles northwest of Cochran, Georgia. The Thalmann transmission corridor crosses the western edge of Paulk's Pasture Wildlife Management Area near the Thalmann substation. The Florida transmission corridor traverses the southwestern portion of the Little Satilla Wildlife Management Area immediately southeast of Offerman, Georgia. There are no other wildlife sanctuaries, refuges, or preserves on the transmission corridors. These corridors do not cross any "critical habitats" as defined in Section 7 of the Endangered Species Act.

Georgia Power Company currently participates in a wildlife management program with GADNR on transmission line corridors. "The Wildlife Incentives for Non-Game and Game Species" (WINGS) program is designed to help land users convert Georgia Power transmission corridors into productive habitat for wildlife. WINGS offers grant money and land management expertise to landowners, hunting clubs, and conservation organizations who commit to participating in the program for 3 years. Georgia Power Company is one of two utilities funding the WINGS program in Georgia.

As described in <u>Section 2.1.7</u>, SNC has no plans to perform major refurbishment activities during the license renewal period; therefore, no refurbishment or other license-renewal-related construction activities would impact important plant and animal habitats. Because no major plant refurbishment activities are anticipated, no further analysis of impacts to terrestrial resources (Issue 40) is required. SNC notes that the HNP terrestrial environment would realize a positive impact from the continuation of existing habitat management programs. On-going habitat management programs are described more fully in the section that follows.

3.1.5 Threatened and Endangered Species

NRC

The environmental report must contain an assessment of ". . . the impact of the proposed action on threatened and endangered species in accordance with the Endangered Species Act." [10 CFR 51.53(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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 49)]

The NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities and continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act may require consultation with the appropriate Federal agency (GEIS Section 3.9 and 4.1).

Background

The (1978) FES for operation of HNP Unit 2 lists 11 amphibian and reptile species, 31 bird species, and 11 mammal species found on the HNP site (Reference 5). It notes that one terrestrial species (presumably the gopher tortoise) is "rare or endangered," but does not identify the species. The FES concludes that operation of HNP would have no effect on terrestrial wildlife, including sensitive species. The shortnose sturgeon (*Acipsenser brevirostrum*) was the only state- or Federally-protected aquatic species known to occur in the Altamaha River in the vicinity of the HNP site when the FES was prepared. One adult shortnose sturgeon and two larval sturgeon of unidentified species were collected during three years (1972-1975) of pre- and post-operational monitoring in the vicinity of HNP (Reference 5). Based on impingement and entrainment studies conducted over the 1974-1975 period (when Unit 1 was operating), the (1978) FES concluded that losses of adult fish and ichthyoplankton due to operation of both units at HNP would not be significant, even during low flow periods. No shortnosed sturgeon (adult, juvenile, larval, or egg) were identified in the impingement and entrainment studies. The FES also concluded that because the thermal (discharge) plume produced under two-unit operation would be small and restricted to a surface layer it would not present a barrier to migrating fish, such as the shortnose sturgeon. Subsequent data collected during 1980 confirmed that operation of two units have minimal impact on fish and icthyoplankton (Reference 58).

NRC evaluated potential impacts to threatened and endangered species of an 8 percent power uprate in 1997 and concluded in an Environmental Assessment that "...conclusions of the FES relative to impact on terrestrial ecology, including endangered or threatened plant or animal species, remain valid for extended power uprate" (63 FR 53473-53478, October 5, 1998). Similarly, the Environmental Assessment concluded that the proposed power uprate would not alter the findings of the FES including impingement and entrainment or the potential for the thermal plume to block up- and downstream movement of anadromous fish (including sturgeon).

In order to update a number of surveys and studies of benthic macroinvertebrates, fish, and wildlife conducted over more than 30 years and summarized in a number of unpublished documents and government reports, SNC in 1998 commissioned surveys of state- and Federally-listed plant and animal species on the HNP site and its transmission corridors. These surveys, described in an *Environmental Field Survey Plan* (Reference 33) were intended to: (1) identify listed species on the HNP site and its transmission corridors and (2) provide a sound basis for the assessment of potential impacts (of plant refurbishment activities and continued operations) to these species. Because of the unique status of the Altamaha River and concern about its freshwater mussel populations (see Attachment C-2), SNC in 1998 also included a survey of mussels in a 12-mile reach of the river up- and downstream of HNP in the environmental field surveys (Reference 33).

For the purposes of the surveys, "listed" species were to include species that the USFWS has listed or proposed for listing as threatened or endangered and species that GADNR has listed or proposed for listing as endangered, threatened, rare, or unusual. Although the NRC guidance (at 10 CFR 51.53) only requires licensees to assess the potential impacts of continuing operation on Federally-listed threatened and endangered species, species listed by GADNR (as endangered, threatened, rare, or unusual) were included in the survey plan in accordance with SNC's corporate commitment to environmental stewardship.

When certain plant species known to be of concern to GADNR but not formally assigned one of four "status designations" (i.e., endangered, threatened, rare, or unusual) were observed by biologists conducting field surveys, they were also documented. Information relating to the occurrences of species protected by the state of Georgia or known to be of special interest to GADNR's Natural Heritage Program (e.g., the Ohoopee bumelia, *Sideroxylon* sp., which has no special status at present) was provided to GADNR in the form of Special Concern Animal Observation Sheets and Special Plant Data Sheets.

Prior to the 1998-1999 surveys, the most recent survey of sensitive plant and animal species at the HNP site was conducted by the Nature Conservancy of Georgia in 1994 (Reference 54). The Nature Conservancy surveys focused on upland areas (primarily pine stands) and did not include transmission line corridors. Records of state- and Federally-listed plants within the transmission corridors are maintained by Georgia Power Company (Reference 66) and the Georgia Natural Heritage Program (Reference 67). No plants listed or proposed for listing by USFWS as endangered or threatened have been recorded on the HNP site, and none were discovered during the 1998-1999 surveys. No plants listed or proposed for listing by GADNR as endangered, threatened, rare, or unusual were previously recorded on the HNP site. A small population of the yellow pitcher plant (*Sarracenia flava*), a species listed as "unusual" by GADNR, was discovered at the HNP site during the 1998-1999 surveys. No other state-listed plants were discovered at the HNP site during the 1998-1999 surveys.

Prior to the 1998-1999 surveys, there were four documented occurrences of state- and Federally-listed plant species along the transmission line corridors: the yellow pitcher plant, the hooded pitcher plant (*Sarracenia minor*), the cutleaf beardtongue (*Penstemon dissectus*), and the hairy rattleweed (*Baptisia arachnifera*). Both pitcher plant species are listed by GADNR as "unusual," while the cutleaf beardtongue is listed by GADNR as "rare." Hairy rattleweed is listed by both GADNR and USFWS as "endangered." The single previously recorded population of hooded pitcher plant on the North Tifton corridor (Reference 66) was not located during the 1998 – 1999 surveys. The single previously recorded population of cutleaf beardtongue on the Thalmann corridor (Reference 66) was located during the surveys. Single previously recorded populations of yellow pitcher plant and hooded pitcher plant on the Thalmann corridor (Reference 66) were not verified during the 1998 - 1999 surveys. According to GADNR-Georgia Natural Heritage Program records (Reference 67), a population of hairy rattleweed was found in 1980 in the vicinity of the Thalmann corridor; it is not known if the population was actually in the corridor or in open woods nearby. These three recorded populations were in (or near) a portion of the corridor that was mowed immediately prior to the 1998-1999 surveys as part of routine corridor maintenance. As a result, plant surveys were not conducted in this portion of the transmission corridor.

No Federally-listed plants were found during the 1998-1999 surveys of the 2,240 acre HNP site and associated transmission line corridors (Reference 65). One plant species, *Sarracenia flava*, listed as "unusual" by GADNR was found on the HNP site proper. Five plant species listed as "threatened", "rare," or "unusual" by GADNR were observed in transmission line corridors. These included *Sarracenia psittacina* (threatened; found in 2 locations in two transmission corridors), *Balduina atropurpurea* (rare; found in 5 locations in 3 transmission corridors), *Penstemon dissectus* (rare; found in a single location), *Sarracenia flava* (unusual; found in 12 locations in 4 transmission corridors), and *Sarracenia minor* (unusual; found in 14 locations in 5 transmission corridors). Further details on these surveys and their findings can be found in *Threatened and Endangered Species Surveys: E. I. Hatch Nuclear Plant and Associated Transmission Line Corridors (1998-1999)* (Reference 65).

No Federally-listed wildlife species were found on the HNP site during the 1998-1999 surveys, but several state-and Federally-listed species were observed in (or evidence of these species was found) or adjacent to existing transmission line corridors. The shed skin of an Eastern indigo snake (listed as "threatened" by USFWS and GADNR), was found in one location in the North Tifton corridor (see Figure 2-5). American alligators (listed as "threatened due to similarity of appearance" by USFWS), were observed at survey locations in 3 transmission corridors. Red-cockaded woodpeckers (listed as "endangered" by USFWS and GADNR) were observed at two locations adjacent to the Duval transmission corridor. Bachman's sparrows (listed as "rare" by GADNR) were observed at locations in two transmission corridors, Duval and Thalmann. Two Federally-listed species not recorded in the 1998-1999 surveys, the threatened bald eagle and endangered wood stork, have been observed by GPC biologists and natural resources managers in the general area of HNP, but neither species is believed to nest in the vicinity of the Plant. Bald eagles have been seen foraging along the Altamaha River upstream and downstream of

HNP. Wood storks have been observed in a beaver pond wetland just east of the HNP cooling towers. The survey report (Reference 65) contains more detailed information on these species, their preferred habitats, and occurrences on SNC-managed lands.

A September 25-26, 1998 survey of the freshwater mussel community in a 12-mile reach of the Altamaha River in the vicinity of HNP documented viable populations of 12 mussel species (Reference 56). Collections were dominated by species that are endemic to the Altamaha River system and species that are considered "Species of Concern" by the USFWS and GDNR because the status of their populations is not known. None of the mussel species collected was state or Federally listed.

Based on historical information and the 1998-1999 surveys, SNC developed a list of state- and Federally-listed species that are known to occur (or believed to occur, based on substantial and credible evidence) on the site, its transmission corridors, or in the Altamaha River adjacent to the HNP site (see Table 3-2). As noted previously, these include species that the USFWS has listed (or proposed for listing) as threatened or endangered and species that GADNR has listed (or proposed for listing) as endangered, threatened, rare, or unusual.

Current Efforts to Enhance Wildlife/T&E Species Habitat

Based on a number of initiatives and programs designed to benefit wildlife, HNP applied for and received corporate certification from the Wildlife Habitat Council in 1994. The Wildlife Habitat Council cited HNP and SNC for a number of successful habitat enhancement projects on the HNP site including: (1) installation and monitoring of nest boxes for songbirds (eastern bluebirds and great-crested flycatchers), barred owls, American kestrels, and wood ducks; (2) establishment and maintenance of food and cover plots for white-tailed deer and eastern wild turkey; (3) the implementation of an extensive reforestation effort with the planting of approximately 1,200 cherry-bark and willow oak seedlings, and (4) the initiation of a timber management plan to produce superior (mast-producing) hardwood timber and enhance wildlife habitat (particularly for bobwhite quail, fox squirrel, and the state-listed gopher tortoise) associated with upland pine stands. Upland pine stands will be maintained through long-rotation timber management (40 to 60 years) and prescribed burning in 3- to 5-year intervals. A substantial amount of the native longleaf pine is planned to be re-established on the 900-acre tract north of the Altamaha River in Toombs County (References 68 and 69), and the area is expected to develop into a wiregrass-longleaf pine community. Several pine upland areas have been burned in recent years to enhance the sandy, prairie-like wiregrass habitat preferred by the gopher tortoise. A number of gopher tortoise burrows were observed on the HNP Site during the 1998-1999 surveys (Reference 65) south of the Altamaha River in areas north, northwest, northeast, and east of the HNP Recreation Center, especially in an area that had been recently subjected to a controlled burn. These gopher tortoise burrows provide cover and habitat for a number of other species, including the federally-listed Eastern Indigo snake.

Summary of Impacts of the Proposed Action

There is no evidence to suggest that any threatened and endangered species have been discernibly affected by more than twenty years of two-unit operation of HNP. SNC has no plans to alter current patterns of operation over the license renewal period. As noted in Section 2.1.7, SNC has no plans to significantly modify or expand HNP over the license renewal term; therefore, no impacts are expected to listed plant and animal species from refurbishment activities. In addition, on-going wildlife habitat improvements (such as the longleaf pine-wiregrass restoration efforts described in the previous paragraphs) are expected to benefit upland wildlife (including the state-listed gopher tortoise and the Federally-listed Eastern indigo snake) associated with this unique ecological community. SNC concludes that there would be no refurbishment-related impacts to threatened and endangered species and any operational impacts over the license renewal term would be small.

SNC contacted GADNR, USFWS, and the National Marine Fisheries Service regarding potential impacts of license renewal on threatened and endangered species. Copies of the SNC letters and agency responses are provided in Attachment C.

3.1.6 Air Quality

NRC

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. [10 CFR 51.53(c)(3)(ii)(F)]

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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 50)]

The NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during the refurbishment outage (GEIS Section 3.3). Information needed would include: (1) the attainment status of the plant-site area; and (2) number of additional vehicles as a result of refurbishment activities.

A "nonattainment area" is defined in accordance with the Clean Air Act Amendments of 1990 as a locality where air pollution levels persistently exceed National Ambient Air Quality Standards. An area that a state has redesignated from nonattainment to attainment is considered a "maintenance area." The counties in which HNP is located, Appling and Toombs, are classified as in attainment for all criteria pollutants. The nearest nonattainment area for criteria pollutants is Henry County, which is approximately 140 miles northwest of HNP. Henry County, a southeastern suburb of Atlanta, is in nonattainment for ozone. Muscogee County (Columbus, Georgia), approximately 150 miles to the west of HNP, formerly a nonattainment area for lead, was recently redesignated (64 FR 17551-17555, April 12, 1999) an attainment ("maintenance") area. However, current EPA regulations require the state of Georgia (Georgia EPD) to demonstrate continued attainment with the lead NAAQS for at least ten years after the approval of a redesignation to attainment. Because the HNP site is not located in or near a nonattainment or maintenance area, an analysis of impacts to air quality (Issue 50) is not required.

3.1.7 Microbiological Organisms

> **NRC**
>
> ***If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow 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. [10 CFR 51.53(c)(3)(ii)(G)]***
>
> ***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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 57)]***

NRC designated impacts on public health from thermophilic organisms a Category 2 issue because the magnitude of the potential public health impacts associated with thermal enhancement of *Naegleria fowleri* could not be determined generically. NRC noted in the GEIS that impacts of nuclear plant cooling towers and thermal discharges are considered to be of small significance if they do not enhance the presence of microorganisms that are detrimental to water quality and public health (GEIS Section 4.6). Information to be ascertained includes: (1) thermal discharge temperature, (2) thermal characteristics of the Altamaha River, (3) thermal conditions for the enhancement of *N. fowleri*, and (4) impacts to public health.

The NRC requires [10 CFR Part 51.53(c)ii(G)] an assessment of the potential impact of thermophilic organisms on the health of recreational users of receiving waters if a nuclear plant uses cooling ponds, cooling lakes, or cooling canals or discharges to a river with an average annual flow rate of less than 3.15×10^{12} cubic feet per year. Because the average discharge for the Altamaha River is 3.65×10^{11} cubic feet per year, NRC considers it a small river, making this issue applicable to HNP.

The Watershed Planning and Monitoring Program of the Environmental Protection Division (EPD) of GADNR was consulted about the possible presence of thermophilic pathogens in the HNP discharge. A copy of the consultation letter is provided in Attachment E. EPD was asked to provide information (including the results of any studies or reconnaissance) on the possible occurrence of pathogenic thermophilic microorganisms in the heated effluent of HNP and guidance on concentrations of these organisms that are considered hazardous to public health. Organisms of concern include the enteric pathogens *Salmonella* and *Shigella*, the *Pseudomonas aeruginosa* bacterium, gram-positive Actinomycetes "fungi," the many species of *Legionella* bacteria, and pathogenic strains of the amoeba *Naegleria*.

EPD has not conducted any studies of thermophilic microorganisms in the HNP discharge and has not set state standards for any of the aforementioned organisms. The only state water quality standard for microorganisms in the Altamaha River (which is classified by EPD as a "Fishing" stream, with water quality suitable for "propagation of fish, shellfish, game, and other aquatic life") applies to fecal coliforms, which are not to exceed 200 organisms per 100 milliliters (geometric mean of at least four samples) between May 1 and October 31 or 1,000 organisms per 100 milliliters between November 1 and April 30. Fecal coliform bacteria are used by many state agencies, including the EPD of GADNR, as indicators of other potentially harmful waterborne microorganisms. When significant levels of coliforms are found in a water supply, additional testing often is conducted to determine if other potentially pathogenic microorganisms are present.

Thermophilic bacteria generally occur at temperatures of 77 to 176 degrees Fahrenheit (°F), with maximum growth at 122 to 140°F. Pathogenic bacteria have evolved to survive in the digestive tracts of mammals and, accordingly, have optimum temperatures of around 99°F (Reference 38). Pathogenic protozoans such as *Naegleria fowleri* have maximum growth and reproduction at temperatures ranging from 95 to 113°F and are rarely found in water cooler than 95°F (Reference 39).

HNP discharge temperatures are monitored weekly by plant personnel and reported to EPD on a quarterly basis. Discharge temperatures range from 60 to 94°F when the plant is operating, with highest temperatures occurring in summer (see Table 2-1). During summer months, when thermophilic organisms are most likely to be present, discharge temperatures have averaged 85.0°F (June), 88.9°F (July), and 88.2°F (August) over the last two years.

HNP discharge temperatures are always below those known to be optimal for growth and reproduction of pathogenic microorganisms but could theoretically permit limited survival of these organisms in summer months. Temperatures in the Altamaha River immediately downstream of the HNP discharge structure are several degrees cooler than those in the immediate area of the discharge outfall (Reference 5) and therefore under normal circumstances would not support the survival of these pathogenic organisms.

Another factor limiting concentrations of pathogenic microorganisms in the HNP discharge is the absence of a seed source or inoculant. Wastewater, whether domestic sewage or industrial wastewater, is usually the source of pathogens in natural waters. The sewage treatment facility at HNP originally consisted of two packaged secondary treatment plants (Plants #1 and #2), each capable of treating 7,500 gallons per day (Reference 3). In 1990, the sewage treatment plant was expanded and upgraded to accommodate an increased sewage treatment demand. The modernized Plant Hatch sewage treatment plant system consists of two 35,000 gallons per day extended aeration activated sludge treatment plants (Plants #3 and #4) which are normally operated in parallel to treat wastewater from site restrooms, shower facilities, and other non-industrial sources. The total discharge flowrate from the two systems is approximately 21,000 gallons per day.

Raw sewage from HNP is pumped to a large surge tank upstream of the sewage plant. The surge tank has a screen and comminutor (shredder) at the inlet to the tank which screen out large debris and break up smaller debris. Sewage is pumped from the surge tank to a distribution box from whence the sewage is distributed to Plants #3 and #4. Each plant has a digestor chamber, aeration chamber, and a clarifier. Effluent from the two plants is routed to the chlorine contact chamber, where calcium hypochlorite is applied at a concentration sufficient to control pathogenic organisms. Treated effluent merges with the combined plant waste streams and flows into a mixing chamber (where chlorine levels are monitored once per week) before discharging to the Altamaha River.

Disinfection in the sewage treatment facility reduces coliform bacteria and other microorganisms to levels that meet state water quality standards. As noted previously in Section 2.1.3, the circulating water system is also chlorinated to control microbial organisms. Moreover, there are no major upstream sources of bacterial organisms because the Altamaha River above HNP flows through a largely rural area and receives no substantial discharges of municipal, industrial, or agricultural wastes.

Given the thermal characteristics of the Altamaha River and the HNP discharge, SNC does not expect HNP operation to stimulate growth and reproduction of pathogenic microorganisms in the Altamaha River downstream of the plant. Under certain circumstances, these organisms might be present in the immediate area of the discharge outfall but would not be expected in sufficient concentrations to pose a threat to downstream water users. Many of these pathogenic microorganisms (e.g., *Pseudomonas, Salmonella*, and *Shigella*) are ubiquitous in nature, occurring in the digestive tracts of wild mammals and birds (and thus in natural waters), but are usually only a problem when the host is immunologically compromised. The thermal characteristics of the HNP discharge would not promote the growth of microorganisms that are detrimental to water and public health; therefore, SNC concludes that the thermal discharge impacts to human health (Issue 57) would be small and mitigation would not be warranted.

3.1.8 Electric Shock

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines "... [i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents .... [10 CFR 51.53(c)(3)(ii)(H)]

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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 59)]

The NRC made impacts of electric shock from transmission lines a Category 2 issue because without a review of each plant's transmission line conformance with the National Electrical Safety Code (Reference 9) criteria, NRC could not determine the significance of the electrical shock potential. Regulation 10 CFR 51.53(c)(3)(ii)(H) does not define the phrase "transmission line." The GEIS indicates that transmission lines use voltages of about 115 or 138 kilovolt (kV) and higher, and that, in contrast, distribution lines use voltages below 115 or 138 kV (Reference 10 at Section 4.5.1, page 4-59). The GEIS also indicates that the transmission line of concern is that between the plant switchyard and its connection with the existing transmission system (Reference 10 at Section 4.5, page 4-59). Information to be ascertained includes: (1) change in line use and voltage since last analysis; (2) conformance with National Electrical Safety Code (1981) standards; and (3) potential change in land use along transmission lines since initial NEPA review.

Objects located near transmission lines can become electrically charged due to the effect of what is often commonly called static electricity but is more precisely termed an electrostatic field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is particularly well insulated from the ground, such as a car on rubber tires, can actually store up an electrical charge, becoming what is called capacitively charged. A person standing on the ground and touching the car receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. The intensity of the shock depends on several things, including the following:

- The strength of the electrostatic field which, in turn, depends on the amount of electricity, called voltage, in the transmission line (more voltage = stronger field = larger shock potential)
- The height of the line above the ground, called vertical clearance (less clearance = larger shock potential)
- The size of the object (larger object = larger shock potential)

In 1977, the NESC adopted a provision that identifies how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98 kV alternating current to ground[1] (Reference 57). The clearance must limit the induced current[2] due to electrostatic effects to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground.[3] The NESC chose this limit as being protective of the health of a person who wears a heart pacemaker. By way of comparison, the shock that one feels on a dry day after walking on a carpet or sliding across a car seat and touching an object is the result of approximately 3 milliamperes of current (Reference 57).

GPC installed the Duval and Thalmann lines in conformance with the 5-milliampere limit but installed the HNP Eastman, Douglas, North Tifton, and Bonaire lines before its adoption by the NESC (see Figure 2-5 for location of lines). At that time, however, the 5-milliampere limit that the Code subsequently adopted was in use by the industry for high voltage lines and GPC used computer modeling in designing the 500-kV North Tifton and Bonaire lines to ensure that the limit was met. However, computer-modeling capabilities have improved greatly since that time and GPC had not modeled the 230-kV Eastman and Douglas lines. For this reason, SNC and GPC have conducted a new evaluation of all of the lines' adherence to the Code's present induced current limit (References 34 and 35). The evaluation is a two-step process in which the analyst first calculates the average strength of the electrostatic field 1 meter (3.28 feet) above the ground beneath the minimum line clearance, and second calculates the induced current value. The lines should be evaluated assuming a final unloaded sag at 120°F.

The largest vehicle that SNC anticipates being under the HNP lines is a tractor trailer parked on a public roadway. The GPC minimum line design vertical clearance, including above a public roadway, at the conductor temperature (120°F) specified by the Code was 33.7 feet for the 230-kV lines and 41.4 feet for the 500-kV lines.[4] GPC entered this input, together with line characteristics such as voltage, current, and conductor position into the Electric Power Research Institute AC/DCLINE program EFION (EPRI/HVTRC) (Reference 36) to obtain electric field strengths, 1 meter above the ground. Assuming a 55-foot object located under, and perpendicular to, the lines (representing a tractor-trailer) the calculated field strength for the 230-kV lines ranged from 0.994 to 2.195 kV per meter, with a maximum average of 1.780 kV per meter. Calculated field strengths for the 500-kV lines range from 3.353 to 6.162 kV per meter, with a maximum average of 4.625 kV.

Using the maximum average field strengths, GPC calculated the steady-state current for a tractor trailer 55 feet long, 8 feet wide, and 13.5 feet high. The resultant values, 1.25 milliamperes for the 230-kV lines and 3.84 milliamperes for the 500-kV lines, are less than the 5-milliampere limit imposed by the Code. Therefore, all the HNP transmission line designs conform to the National Electric Safety Code provisions for preventing electric shock from induced current.

No changes have been made to the lines' voltage since installation and, as described in <u>Section 2.1.6</u>, maintenance practices ensure continued conformance with design specifications. SNC concludes that HNP transmission lines meet the National Electrical Safety Code guidelines for preventing electric shock from induced currents and, therefore, further assessment of the impact of the proposed action on the potential shock hazard is not required. SNC adopts by reference the GEIS conclusion that electrical shock (Issue 59) is of small significance for such lines. Due to the small significance of the issue, mitigation measures, such as installing warning signs at road crossings or, in the extreme, increasing clearances, are not warranted.

---

1. Part 2, Rules 232C1c and 232D3c.
2. The National Electrical Safety Code and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases have the same meaning here.
3. Induced currents can also be caused by electromagnetic fields, but NESC provision is limited to electrostatic effects.
4. 41.4 feet was also the minimum design vertical clearance for the Duval and Thalmann lines.

3.1.9 Housing Impacts

NRC

The environmental report must contain " . . . [a]n assessment of the impact of the proposed action on housing availability . . . ." [10 CFR 51.53(c)(3)(ii)(I)]

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 areas with growth control measures that limit housing development. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 63)]

. . . small impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs. [GEIS Section 4.7.1.1]

The NRC made housing impacts a Category 2 issue because impact significance depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (GEIS Section 3.7.2). Local conditions to be ascertained are: (1) area population categorization as low, medium, or high; and (2) applicability of growth control measures, and (3) vacancy rate for area housing.

This issue addresses housing impacts resulting from refurbishment activities and continued operations. As described in Section 2.1.7, SNC has no plans to perform major refurbishment activities at HNP. SNC concludes that there would be no refurbishment-related impacts to area housing. Therefore, the following discussion focuses on assessing the impacts of continued operations on local housing availability.

Attachment C of the GEIS presents a population characterization method that is based on two factors, "sparseness" and "proximity" (GEIS Section C.1.4). Sparseness measures population density and city size within 20 miles of the site, and proximity measures population density and city size within 50 miles. Each factor has four categories of density and size (GEIS Table C.1), and a matrix is used to rank the population category as low, medium, or high (GEIS Figure C.1). Population in the HNP area was categorized by the NRC as "low" (GEIS Table C.2). Tables 3-3 and 3-4 provide the population distribution for the area surrounding HNP based on 1990 census data. The population density within a 20-mile radius of HNP is approximately 43 persons per square mile[5] and there is no city with a population of 20,000 within 20 miles, giving the site a sparseness Category 2. The population density within a 50-mile radius is approximately 43 persons per square mile and there is no city with a population of 100,000 within 50 miles, giving the site a proximity Category 1. These values combine to give the HNP population a category measure of 2.1; a "low" category as defined by GEIS Figure C.1.

In the GEIS, NRC describes the license renewal term workforce as those personnel on-site during the original operating period plus additional personnel to support the requirement for more frequent surveillance and inspection. NRC analysis of the potential license renewal term workforce requirements demonstrates that only one additional worker will be required on a continuous basis for maintenance and inspection; however, as many as 20 to 60 additional non-outage workers per unit may be required intermittently to perform maintenance and inspections. For the GEIS socioeconomic analyses, NRC assumes as many as 60 additional permanent workers per unit will be required to conduct increased inspection, surveillance, testing, and

5. The calculation for the number of persons per square mile for a 20-mile radius is as follows: 53,680 persons ÷ $[(20 \text{ miles})^2 \times 3.14] = 42.7$ persons per square mile.

maintenance. NRC uses this conservative value to represent an upper bound of the potential socioeconomic impacts.

As described in Section 2.1.7, SNC does not anticipate the need to increase the on-site workforce during the license renewal period and therefore anticipates no housing impacts as a result of license renewal. However to demonstrate the upper bounds of potential impacts to area housing, SNC applies the bounding analytical approach used by NRC in the GEIS with one alteration. As described previously, NRC applied a bounding workforce estimate of 60 license renewal workers per unit to estimate potential housing impacts. SNC anticipates that the increased inspection and maintenance would be performed mostly during outages that generally are staggered so that they do not coincide. Therefore, SNC believes that it is unreasonable to assume that each unit would require an additional 60 workers. Instead, as a reasonably conservative estimate, SNC is assuming that HNP would require a total of 60 additional workers to perform the increased inspection and maintenance activities to support operations through the period of extended operations.

SNC bases the bounding housing analysis on the following assumptions: (1) a total of 60 additional full-time employees through the license renewal period; (2) all direct and indirect jobs would be filled by in-migrating workers; (3) the residential distribution of new workers would be similar to the residential distribution of current workforce; and (4) each new job created (direct and indirect) represents one housing unit. Adding fulltime workers would have the indirect effect of creating additional jobs and related population growth in the community. SNC uses the Georgia employment multiplier (4.0769) (Reference 37) to calculate the total direct and indirect jobs in service industries that would be supported by the spending of the HNP workforce. The addition of 60 license renewal employees would generate approximately 185 indirect jobs. With each new worker (direct and indirect) representing one housing unit, license renewal would generate a demand for 245 housing units.

SNC assumes that the residential distribution of the in-migrating license renewal workers would be similar to the distribution of existing workers. Approximately 71 percent of the HNP workforce reside in Appling and Toombs Counties (Section 2.1.8). Section 2.1.8 illustrates that the number of employees residing in any other one single county is not significant. As shown below, the combined number of housing units for the 2-county area is approximately 16,581 with a vacancy rate of approximately 11 percent (1,900 vacant units) (Reference 40). In this area there are no growth control measures that limit housing development.

County	Housing Units	Vacant Units
Toombs	9,952	1,148
Appling	6,629	795
Total	16,581	1,943

A demand for 174 housing units (71 percent of 245 housing units) would represent a 9 percent decrease in housing availability. SNC does not anticipate the resulting decrease in housing availability for the bounding case scenario (60 additional workers) to create a discernible change in housing availability, rental rates or housing values, or spur housing construction or conversion, and therefore concludes that license renewal impacts to housing (Issue 63) would be small, and would not warrant mitigation.

3.1.10 Public Services, Public Utilities

> ***NRC***
>
> ***The environmental report must contain " . . . an assessment of the impact of population increases attributable to the proposed project on the public water supply." [10 CFR 51.53(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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 65)]***
>
> ***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 quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services. [GEIS Section 3.7.4.5]***

The NRC made public utility impacts a Category 2 issue because an increased problem with water availability may occur in conjunction with plant demand and plant-related population growth as a result of current water shortages in some areas (GEIS Section 4.7.3.5). Local information needed would be a description of water shortages experienced in the area and an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water system considers both plant demand and plant-related population growth demand on local groundwater resources. As described in Section 2.1.5, HNP does not use a municipal water supply; therefore, operations do not directly affect any public water supply system. As described in Section 3.1.3, HNP groundwater use does not have a noticeable impact on offsite wells drawing from the Floridan Aquifer. Because plant demand is not expected to alter offsite groundwater use in the Floridan Aquifer, HNP operations is not expected to indirectly impact public water supply systems located in the vicinity of the Plant. Section 3.1.10 focuses on the potential indirect impact resulting from additional workers moving to the area and placing additional demands on public water supply systems.

As described in Section 2.1.7, SNC does not anticipate the need to increase the on-site workforce during the license renewal period and therefore anticipates no impacts to the public water systems as a result of license renewal. However, to demonstrate potential population-related impacts to area public water services, SNC assumes a bounding license renewal workforce of 60 additional full-time workers (described in Section 3.1.9). To determine the license renewal population growth, SNC assumes that (1) all direct and indirect jobs would be filled by in-migrating workers and that (2) each new worker would represent one family. As described in Section 3.1.9, the conservative estimate of 60 additional full time workers could generate as many as 245 direct and indirect jobs. If each new worker represents one new family, the population in the area could increase by approximately 785. SNC also assumes that the residential distribution of the workers would be similar to the current worker distribution provided in Section 2.1.8. Therefore, approximately 560 new residents (71 percent) would be expected to reside in Appling and Toombs Counties.

In Appling County, the municipalities of Baxley and Surrency are the only areas in the County served by public water supply systems. The city of Baxley provides water service within the city and outside the city limits in certain areas through a distribution system that currently utilizes four wells screened to the Floridan Aquifer. These wells are capable of producing approximately 3.1 million gallons per day. The estimated daily demand is approximately 600,000 gallons.

(Reference 46). Considering the current demand, the City of Baxley has approximately 2.5 million gallons per day of available capacity.

The water system serving the Town of Surrency consist of two wells that pump from the Floridan Aquifer and are capable of producing 290,000 gallons per day.

Toombs County has three municipal water supply systems owned and operated by the cities of Lyons, Santa Claus, and Vidalia. All three municipal systems withdraw water from the Floridan Aquifer. The City of Lyons has a capacity of 4.3 million gallons per day. Current demands are 0.70 million gallons per day, giving the City a reserve capacity of 3.6 million gallons per day. The City of Vidalia has a capacity of 4.9 million gallons per day and current demands require 1.98 million gallons per day. Therefore, the City of Vidalia has a reserve capacity of approximately 3 million gallons per day. The City of Santa Claus is served by one well; however, demand data is not available (Reference 52).

For Appling and Toombs Counties combined, the total available capacity is approximately 9.4 million gallons per day. The average American uses between 50 and 80 gallons per day for personal use (Reference 53). Using this consumption rate, the plant-related population increase would generate a demand on public water supply systems of 45,000 gallons per day. This demand represents less than 0.5 percent of the available capacity, assuming that 100 percent of the growth attributable to license renewal were served by these municipal systems. Based on the level of demand that would be placed on the public water systems serving Appling and Toombs Counties, SNC concludes that plant-related population growth would require no additional capacity. The impacts would be small, either not detectable or so minor that they would not destabilize nor noticeably alter any important attribute of the resource. The impacts from the bounding case scenario for projected HNP license renewal-related population growth would be small. Therefore, SNC has also concluded that mitigation, such as lowering of wells, would not be necessary.

3.1.11 Public Services, Education

> ***NRC***
>
> ***The environmental report must contain " . . . [a]n assessment of the impact of the proposed action on . . . public schools (impacts from refurbishment activities only) within the vicinity of the plant. . . ." [10 CFR 51.53(c)(3)(ii)(I)]***
>
> ***Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 66)]***
>
> ***. . . small impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service . . . Large impacts are associated with enrollment increases greater than 8 percent. [GEIS Section 3.7.4.1]***

The NRC made impacts to education a Category 2 issue because site-specific and project-specific factors determine the significance of impacts (GEIS Section 3.7.4.1). Local factors to be ascertained include: (1) project-related enrollment increases; and (2) status of the student/teacher ratio.

In Appling County there are four elementary schools, one middle school, and one high school. During the 1998-99 school year, total enrollment was approximately 3,510. During this period the average number of students per teacher was 15 (Reference 41). In Toombs County there are two elementary schools, one middle school, and one high school. The combined enrollment for the 1998-99 school year was approximately 2,660 (References 42, 43, 44, and 45). As described in Section 2.1.7, SNC has no plans for major refurbishment activities; therefore, there would be no impact from refurbishment activities on area public schools' ability to provide educational services, and no additional teaching staff or classroom space would be needed. Because of the lack of major plant refurbishment, no analysis of impacts to public schools (Issue 66) is required.

3.1.12 Offsite Land Use, Refurbishment

> ***NRC***
>
> ***The environmental report must contain " . . . [a]n assessment of the impact of the proposed action on . . . land-use . . . within the vicinity of the plant . . . ." [10 CFR 51.53(c)(3)(ii)(I)]***
>
> ***Impacts may be of moderate significance at plants in low population areas. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 68)]***
>
> ***. . . if plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, (2.6 km^2) and at least one urban area with a population of 100,000 or more within 80 km (50 miles). [GEIS Section 3.7.5]***

The NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth; (2) patterns of residential and commercial development; (3) population density; and (4) proximity to an urban area of at least 100,000.

A description of the offsite land use for the HNP area is provided in Section 3.1.13.

As described in Section 2.1.7, SNC has no plans to perform major refurbishment activities; therefore, there would be no impact from refurbishment activities on land use within the vicinity of HNP. Because of lack of major plant refurbishment, no analysis of impacts to offsite land use owing to refurbishment (Issue 68) is required.

3.1.13 Offsite Land Use, License Renewal Term

NRC

The environmental report must contain " . . . [a]n assessment of the impact of the proposed action on . . . land-use . . . within the vicinity of the plant . . . ." [10 CFR 51.53(c)(3)(ii)(I)]

Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 69)]

. . . if plant-related population growth is less than five percent of the study area's total population off-site land-use changes would be small . . . [GEIS Section 3.7.5]

If the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has preestablished patterns of development and has provided adequate public services to support and guide development. [GEIS Section 4.7.4.1]

The NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land use changes may be perceived to be beneficial by some community members and adverse by others. Therefore, the NRC could not assess the potential significance of site-specific offsite land use impacts (GEIS Section 4.7.4.1). Site-specific factors to consider in an assessment of new-tax-driven land-use impacts include: (1) the size of plant-related population growth compared to area's total population; (2) the size of the plant's tax payments relative to the community's total revenue; (3) the nature of the community's existing land use pattern; and (4) the extent to which the community already has public services in place to support and guide development.

The Appling County Joint Planning Board has prepared a comprehensive plan to guide County development and growth (Reference 46). Unless otherwise specified, the Section 3.1.13 description of the County is from that plan.

The early economy of Appling County was based on farming, livestock, and timber industries. Municipalities of the County (Baxley, Surrency, and Graham) were locally incorporated in the late 1800's and early 1900's and located along the Brunswick to Macon Railroad (now owned and operated by Norfolk Southern Railroad). The City of Graham was only recently recognized by the Georgia State Legislature receiving its charter in 1991. Today, the County remains rural with approximately 98 percent of the land use in agriculture, forest, or vacant with most of the developed acreage near the city of Baxley. Table 3-5 provides a breakdown of the County land use.

Land use projections show that new commercial and industrial developments are expected to concentrate in Baxley and along the Highway 341 corridor which runs parallel to the Norfolk Southern rail line, while new residential development will be encouraged in and near the cities, particularly Baxley (see Figure 2-2 for location of features). The rest of the County is expected to remain in agricultural and forest uses. The County does not have specific regulations concerning zoning, subdivisions, or other land development controls in place to implement or control development.

The population of Appling county is approximately 15,700. Appling County and its municipalities have not realized significant growth during the 30-year period of 1960 through 1990. The period of strongest growth was the 1970's (coincident with HNP construction). Since 1980, growth has been almost stagnant, with a 1 percent population increase, and there are indications of significant out-migration. Population projections indicate that the County population is expected to reach 23,000 by 2010.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components, population-driven and tax-driven impacts (GEIS Section 4.7.4.1). Based on the GEIS case study analysis, NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small, because population growth caused by license renewal would represent a much smaller percentage of the local areas' total population than has operations-related growth. NRC also projects that new tax-driven land use changes may be moderate at a number of sites and large at some others (GEIS Section 4.7.4.2).

Population-Related Impacts

SNC does not anticipate the need to increase the on-site workforce during the license renewal period (Section 2.1.7). Therefore, SNC anticipates no population-related land use impacts as a result of license renewal. However, to demonstrate a bounding scenario of potential population-related impacts to area land use, SNC applies a bounding workforce estimate of 60 additional full-time workers (described in Section 3.1.9) in the following analysis.

To determine the license renewal population growth, SNC assumes that (1) all direct and indirect jobs would be filled by in-migrating workers to Appling County and that (2) each new worker would represent one family. According to the 1990 Census, the Appling County population is approximately 15,700 with an average family size of 3.21. As described in Section 3.1.9, the conservative estimate of 60 additional fulltime workers could generate as many as 245 direct and indirect jobs. If each new worker represents one new family, the population of Appling County could increase by approximately 785. Because the bounding population growth estimate associated with the HNP's continued operation would represent only a 5 percent increase in Appling County's population, SNC considers new population-related land use impacts of worker in-migration to be small.

Tax-Revenue-Related Impacts

NRC used a two-step process in analyzing tax-revenue-related impacts: first determining the significance of nuclear plant tax payments to the local taxing jurisdiction, and second defining and determining the significance of resultant land use changes. The NRC determined that the significance of tax payments as a source of local government revenue would be small if new tax payments are less than 10 percent of the taxing jurisdiction's revenue, moderate if payments are between 10 and 20 percent of a taxing jurisdiction's revenue, and large if the payments are greater than 20 percent of revenue (GEIS Section 4.7.2.1). The NRC defined the magnitude of land-use changes as follows (GEIS Section 4.7.4):

- Small – Very little new development and minimal changes to an area's land-use pattern
- Moderate – Considerable new development and some changes to land-use pattern
- Large – Large-scale new development and major changes in land use pattern

The NRC further determined that if a plant's tax payments are projected to be a dominant source of a community's total revenue (i.e., greater than 20 percent of revenue), new tax-driven land-use changes would be large.

Table 3-6 provides a comparison of total tax payments made for HNP and Appling County's total tax digest. For the 5-year period between 1994 and 1998, HNP tax payments represent approximately 70 percent of the County revenue. Using NRC's criteria, HNP tax payments are of large significance to Appling County. For the reasons presented below, however, SNC does not anticipate large land-use changes as a result of HNP tax revenues.

As described in Section 2.1.7, SNC does not anticipate major refurbishment or construction during the license renewal period. Therefore, SNC does not anticipate any increase in the assessed value of HNP due to refurbishment-related improvements nor any related tax-increase-driven changes to offsite land use and development patterns.

HNP has been and would probably continue to be the dominant source of tax revenue for the County. However, despite having this income source since plant construction, Appling County has not experienced large land-use changes. The HNP environs have remained largely rural, County population growth rates post-HNP-construction have been minimal, and County planners are not projecting large changes. SNC believes continued operation of HNP would be important to maintaining the current level of development and public services and does not anticipate plant-induced changes to local land-use and development patterns.

Conclusion

SNC views the continued operation of HNP as a significant benefit to Appling County through direct and indirect salaries and tax contributions to the County. Because population growth related to the renewal of HNP is expected to be relatively small and there would be no new-tax impacts to the Appling County land use, SNC concludes that HNP license renewal would have a continued beneficial impact on Appling County.

3.1.14 Public Services, Transportation

NRC

The environmental report must contain an assessment of " . . . 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." [10 CFR 51.53(c)(3)(ii)(J)]

Transportation impacts are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 70)]

Small impacts would be associated with a free flowing traffic stream where users are unaffected by the presence of other users (level of service A) or stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished (level of service B). (GEIS Section 3.7.4.2)

The NRC made impacts to transportation a Category 2 issue because impact significance is determined primarily by road conditions, existing at the time of the project, that NRC could not forecast for all plants (GEIS Section 3.7.4.2). Local road conditions to be ascertained are: (1) level of service conditions and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

The transportation system in Appling County includes two major highways, U.S. Highway 1 and U.S. Highway 341. U.S. Highway 1 runs north and south bisecting the County. This two-lane highway is located along the western border of HNP and provides the sole access to HNP. U.S. Highway 341 runs east and west along the Norfolk Southern rail line and links the municipalities and developed areas of the County. Both of the highways are part of the Governor of Georgia's Economic Development System which was established to provide access to smaller cities and encourage economic development throughout the State.

U.S. Highway 1 is considered a rural highway. In the vicinity of HNP (Lyons, Georgia to Baxley, Georgia), it is a two-lane highway with no traffic signals. In 1998, the annual average daily traffic count taken north of the Site was 4,339 and south of the Site was 5,314 (Reference 47). These values indicate that volume in the vicinity of HNP is low. Long-range plans for this developmental highway include a construction project to widen U.S. Highway 1 to four lanes, providing four-lane access to Baxley from Interstate 16. This project is anticipated to begin within 5 years and likely would be completed prior to the expiration of the current operating licenses.

As described in Section 2.1.7, SNC has no plans to perform major refurbishment activities; therefore, there would be no impact to local transportation from refurbishment activities. Because of the lack of major plant refurbishment, no analysis of local transportation during periods of license renewal refurbishment activities (Issue 70) is required.

SNC does not anticipate the need to increase the on-site workforce during the license renewal period (Section 2.1.7). Therefore, SNC anticipates no impacts to the local transportation system as a result of operations during the license renewal term. However, to demonstrate a bounding scenario of potential impacts to the local transportation system, SNC applies a workforce estimate of 60 additional workers (described in Section 3.1.9) in the following analysis. Using the traffic data presented above, the addition of 60 workers at the site would represent approximately 1.4 percent increase in traffic volume on U.S. Highway 1 north of the Plant and approximately 1.1 percent increase in traffic volume south of the Plant. Considering the fact that U.S. Highway 1 is scheduled to be a 4-lane highway at the time of license renewal, the increase in traffic volume attributable to license renewal will likely not be detectable. In addition, turn lanes and traffic signs on U.S. Highway 1 at the plant entrance contribute to the safety of the traveling public. Therefore, SNC concludes that impacts on the local transportation during the license renewal period (Issue 70) would be small and mitigation would not be warranted.

3.1.15 Historic and Archaeological Resources

> ***NRC***
>
> ***The environmental report must contain an assessment of "... whether any historic or archaeological properties will be affected by the proposed project." [10 CFR 51.53(c)(3)(ii)(K)]***
>
> ***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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 71)]***
>
> ***Sites are considered to have small impacts to historic and archeological resources if (1) the State Historic Preservation Office (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about the character; and (3) if the conditions associated with moderate impacts do not occur. (GEIS Section 3.7.7)***

The NRC made impacts to historic and archeological resource a Category 2 issue because determinations of impacts to historic and archeological resources are site-specific in nature, and the National Historic Preservation Act mandates that determination of impacts must be made through consultation with the State Historic Preservation Office (SHPO) (GEIS Section 4.7.7.3).

In Appling County three historic sites are listed on the National Register of Historic Places. Each of these sites is located within the city limits of Baxley, over ten miles south of HNP. The Georgia Register of Historic Places does not recognize any additional properties within a 10-mile radius of HNP. As described in Section 3.1.7, SNC does not anticipate major refurbishment or construction during the license renewal period on the Plant site or transmission lines. Therefore, SNC concludes that continued operation of HNP through the license renewal period will have no adverse affects on historic or archeologic resources (Issue 71). SNC has initiated consultations with the SHPO regarding HNP license renewal. A copy of the consultation letter is provided in Attachment D.

3.1.16 Severe Accident Mitigation Alternatives

> ***NRC***
>
> ***The environmental report must contain a consideration of alternatives to mitigate severe accidents "... [i]f 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 . . . ." [10 CFR 51.53(c)(3)(ii)(L)]***
>
> ***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. [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 76)]***

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operational envelop) that results in the release or a potential for release of radioactive material to the environment. Generally, NRC categorizes accidents as "design-basis" or "severe." Design-basis accidents are those for which the risk is great enough that an applicant is required to design and construct a plant to prevent unacceptable accident consequences. Severe accidents are those considered too unlikely to warrant design controls.

Historically, NRC has not included in its EISs or environmental assessments any analysis of alternative ways to mitigate the environmental impact of severe accidents. A 1989 court decision ruled that, in the absence of an NRC finding that severe accidents are remote and speculative, severe accident mitigation alternatives (SAMAs) should be considered in the NEPA analysis [*Limerick Ecology Action v. NRC*, 869 F.d 719 (3rd Cir. 1989)]. For most plants, including HNP, license renewal is the first licensing action that would necessitate consideration of SAMAs.

The NRC concluded in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents met the Category 1 criteria, but NRC made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation (i.e., Individual Plant Examination [IPE] and Accident Management) have not been completed for all plants. Since these programs have identified plant programmatic and procedural improvements (and in a few cases, minor modifications) as cost-effective in reducing severe accident and risk consequences, NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal. Site-specific information to be presented in the environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes to key underlying assumptions.

Analysis

The results of the HNP-specific analyses for severe accidents (Attachment F) show that the total core damage frequency is estimated at 1.6384×10^{-5} per year (internal and external events) and the risk is estimated at 3.372 person-rem per year. For the current residual severe accident risk, a bounding SAMA analysis was performed using probabilistic risk assessment (PRA) techniques and making use of industry studies and NRC reports providing guidance on performing the cost-benefit analysis. This bounding analysis demonstrates that plant enhancements (severe accident mitigation and containment performance improvements) in excess of $500,000 are not cost-justified based on averted public health risk.

Although risk assessment studies are subject to varying degrees of uncertainty in the estimated core damage frequency, person-rem risk, and in the cost to implement alternatives, the results of SNC's analysis show that the cost of implementing any of the alternatives is as much as several orders of magnitude higher than the estimated averted risk values. Therefore, no additional severe accident mitigation alternatives are cost-beneficial even when the uncertainties in the risk assessment process are considered. Attachment F summarizes the evaluation of SAMAs for HNP.

As the environmental impacts of potential severe accidents are of small significance and because additional measures to reduce such impacts would not be justified from a public risk perspective, SNC concludes that no additional severe accident mitigation alternative measures beyond those already implemented during the current term license are warranted for HNP.

3.1.17 New and Significant Information

> **NRC**
>
> ***The environmental report must contain any new and significant information regarding the environmental impacts of license renewal which the applicant is aware. [10 CFR 51.53(c)(3)(iv)]***
>
> ***. . . absent new and significant information, the analyses for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal . . . . (Discussion of Regulatory Requirements, 61 FR 109, June 5, 1996, page 2848)***

Description of Process

The HNP Environmental Protection Plan (EPP) and SNC Environmental Services procedures govern review of environmental issues. Changes in plant design, operation, or tests and experiments with potential for environmental impact are reviewed in accordance with established procedures and responsibilities to ensure that such activities do not involve an unreviewed environmental question or change to the EPP. The environmental impacts of license renewal including new and significant information for Plant Hatch were evaluated prior to submittal of the Environmental Report. Established procedures and responsibilities ensure that any new and significant information related to renewal of Plant Hatch licenses will be identified, reviewed and addressed during the period of NRC review.

Review of Environmental Issues prior to ER Submittal

SNC Environmental Services performed an evaluation of environmental issues applicable to license renewal for Plant Hatch (Reference 70). This evaluation was performed on the Category 1 issues appearing in 10 CFR 51, subpart A, Appendix B, Table B-1 to verify that the conclusions of the GEIS remain valid with respect to Plant Hatch.

As a result of this review, SNC 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 HNP, that would alter regulatory or GEIS statements regarding Category 2 issues, or that would suggest any other measure of license renewal environmental impact.

3.1.18 Environmental Justice

> **NRC**
>
> ***"The need for and the content of an analysis of environmental justice will be addressed in the plant-specific reviews." [10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 34)]***

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. The Presidential Memorandum that accompanied Executive Order 12898 emphasized the importance of using existing laws, including the National Environmental Policy Act (NEPA), to identify and address environmental justice concerns, "including human health, economic, and social effects, of Federal actions." The Council on Environmental Quality (CEQ), which oversees the Federal government's compliance with Executive Order 12898 and NEPA, issued "Environmental Justice Guidance Under the National Environmental Policy Act" (Reference 71) on December 10, 1997. This document provides general guidance and assists Federal agencies with the development of NEPA procedures so that environmental justice concerns are effectively identified and addressed.

Although the NRC is not subject to Executive Order 12898, it has voluntarily committed to conducting environmental justice reviews of actions under its jurisdiction. Specific guidance is provided in Attachment 4 to NRR (Office of Nuclear Reactor Regulation) Office Letter Number 906, Revision 1: "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues" (Reference 72).

These two documents (References 71 and 72) do not provide a standard approach or formula for identifying and addressing environmental justice issues. Instead, they offer Federal agencies general principles for conducting an environmental justice analysis under NEPA. They are the basis for the environmental justice review discussion that follows.

Environmental Impacts from the Proposed Action

SNC's analysis of the pertinent Category 2 issues [defined at 10 CFR 51.53(c)(3)(ii)] determined that impacts to human health and the environment from the operations of HNP over the license renewal term would be small. Based on this review of Category 2 issues as discussed in Sections 3.1.2 through 3.1.15 of this document, an exhaustive demographic analysis and assessment of potential environmental justice impacts were not conducted. This phased approach to the assessment of potential environmental justice impacts is consistent with both CEQ and NRC guidance. The NRC guidance makes clear that if no significant impacts are anticipated from the proposed action, then "...no member of the public will be substantially affected" and, as a consequence, "...there can be no disproportionate high and adverse effects or impacts on any member of the public including minority or low income populations."

Environmental Impact Site(s)

Per the NRR Interim Procedure for Environmental Justice Reviews (Reference 72), environmental impact sites must be designated for all adverse human health or environmental impacts which are known to be significant or perceived as significant by groups or individuals. As noted above, based on the review of Category 2 issues, SNC has determined that no "environmental impact sites" exist at or around HNP. No significant adverse human or environmental impacts are expected as a result of operations over the license renewal term.

Selection of Geographic Area

The geographic area is defined as a larger area that encompasses all of the potential environmental impact sites (Reference 72). SNC examined the geographic distribution of minority and low-income populations within a 50-mile radius of HNP. The 50-mile radius (geographic area) contains 78 census tracts (1990 US Census). Census tracts were included in the analysis if 50 percent of their area lay within the 50-mile radius. Those tracts with less that 50 percent of their area contained within the 50-mile radius were excluded from analysis. Census data from the 78 census tracts were compared to averages for the State of Georgia in order to determine the presence of low-income or minority populations.

Demographics within 50-Mile Radius of HNP

Minority populations as defined in the interim NRR Procedure (Reference 72) occur in 14 of the 78 census tracts (Figure 3-1). Minority populations were considered to be present when the percentage of minority individuals in a census tract exceeded the state average by 10 percent or more. For example, for a Black minority population to be present, the percentage of Blacks in a census tract had to greater than 37 percent. When individual minority populations were present, they were always Black. Other minorities were present, including substantial numbers of Hispanics in Long and Liberty counties, but they did not satisfy the definition of "minority populations" in the NRR Procedure (Reference 72) (Figure 3-2). The determination of minority population must consider both individual and aggregate minority populations. Aggregate minority populations were present in 11 of the 14 minority population tracts (Figure 3-3). Table 3-7 presents a more detailed breakdown of minority groups in each census tract containing a minority population.

Low income populations as defined in the interim NRR Procedure (Reference 72) occur in 28 of the 78 census tracts, as presented in Figure 3-4. The percentage of households below the poverty level for the state of Georgia (the total geographic region) is 15 percent. The 28 tracts containing low-income populations have a percentage of households under the poverty level greater than 25 percent (greater than or equal to 10 percent above the level for the total geographic region). Table 3-8 presents a more detailed description of each census tract containing a low-income population.

Based on low-income housing and minority population data from the 1990 census, the geographic area for HNP contains populations that would require an environmental justice review if environmental impact sites were present in these areas. Table 3-9 presents a population description of each county within the 50 mile radius that includes minority and low income details.

Conclusions

As part of its assessment of the proposed action, SNC examined potential impacts to air, land, water, and cultural resources within about 50 miles of HNP. SNC has determined that no significant offsite impacts would be created by the renewal of the HNP operating licenses. This conclusion is supported by the review performed of the Category 2 issues as defined in 10 CFR 51.53(c)(3)(ii). As the interim NRR Procedure acknowledges, if no significant offsite 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 on any member of the public, including minority and low-income populations, resulting from the renewal of the HNP licenses. In such instances, a qualitative review of potential environmental justice impacts is adequate and no mitigation measures need be described.

3.2 ALTERNATIVES

NRC

. . . the applicant shall discuss in this report the environmental impacts of alternatives . . . . [10 CFR 51.53(c)(2)]

. . . GEIS contains a discussion of the environmental impacts of alternative energy sources . . . . The information in the GEIS is available for use by the NRC and the licensee in performing the site-specific analysis of alternatives . . . . (Supplementary information to the final rule, 61 FR 28467 - 28497, June 5, 1996, at Section III.B.3, page 28472, column 3)

As discussed in Section 2.2 and consistent with the NRC license renewal decision-making standard, Section 3.2 provides sufficient information to clearly indicate whether an alternative would have greater environmental impact than the proposed action (i.e., license renewal), without trying to detail every adverse impact. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. SNC has made effort not to bias the comparison in favor of license renewal by reasonably underestimating, rather than overestimating, the environmental impacts of alternatives to license renewal. For example, SNC assumes maximum reuse of existing facilities and high emissions removal efficiencies.

Sections 3.2.2 and 3.2.3 discuss the following potential environmental impacts: land use, ecology, aesthetics, water quality, air quality, solid waste, human health, socioeconomics, and culture. These are the same impacts, in the same order, that NRC analyzes alternatives to license renewal in the GEIS (GEIS Section 8.1). Sections 3.2.2 and 3.2.3 make frequent reference to the impact significance categories that NRC used (i.e., small, moderate, and large). Section 3.1.1 defines these impact categories.

3.2.1 No Action

As described in Section 2.2.1, the no action alternative refers to a scenario in which SNC would decommission HNP after expiration of the current licenses. Impacts associated with decommissioning HNP would be bounded by the discussion in Chapter 7 of the GEIS and NUREG-0586 (Reference 62) and would occur regardless of which feasible alternative (discussed below) was implemented. Decommissioning after 60 years of operations (i.e., after license renewal) would not be significantly different from those occurring after 40 years (i.e., without license renewal).

3.2.2 Coal-Fired Generation

Land Use

The coal-fired generation alternative would necessitate converting roughly an additional 900 acres of the HNP Site to industrial use (plant, coal storage, ash and scrubber sludge disposal). Currently, most of this land is forested (Figure 2-3). These changes would noticeably alter current HNP Site land use patterns and would be a moderate impact. Additional land use changes in an undetermined coal-mining area outside of the HNP Site region of influence would likely result from mining necessary to supply 40 years worth of coal.

Construction at a new site would impact roughly an additional 150 acres for offices, roads, parking areas, and a switchyard. As stated in Section 2.2.2, an additional 300 acres would be needed for transmission lines (assuming the plant is sited 10 miles from nearest transmission line intertie connection). An additional 160 acres also would be needed for a rail line for coal delivery (assuming 10 miles from nearest railway connection). Depending particularly on transmission line and rail line routing, this alternative could result in moderate to large land use impacts.

Ecology

Siting at the existing HNP Site would have a moderately large to large ecological impact because of the need to convert roughly 900 acres of established forested land to industrial use (plant, coal storage, ash and scrubber sludge disposal). However, the use of an existing intake and discharge system, to which the area aquatic communities have become acclimated, would limit operational impacts.

Even at another existing power plant site, adding the HNP alternative coal-fired generation would introduce construction impacts and new incremental operational impacts. At a greenfield site, an undisturbed area, the impacts would certainly alter the ecology. These ecological impacts could be moderate to large. Impacts would include wildlife habitat loss and reduced productivity, and could include habitat fragmentation and a local reduction in biological diversity.

Aesthetics

The three power plant units, which could be as much as 200 feet tall, would be visible over intervening trees for miles around. The three 600-foot tall stacks could be visible at a distance of approximately 4 miles during the summer months and approximately 10 miles in the winter. In contrast, the existing HNP reactor buildings and single main exhaust stack are 200 and 393 feet respectively (References 2 and 4). The existing mechanical draft cooling towers are approximately 60 feet tall. The addition of three 600-foot tall stacks for the coal-fired alternative would contrast with what is otherwise the natural-appearing rural area, with woods and farming areas, and would be a moderate visual aesthetic impact compared to the existing HNP facility.

Coal-fired generation would introduce additional mechanical sources of noise that would be audible offsite. Sources contributing to total noise produced by plant operation are classified as continuous or intermittent. Continuous sources include the mechanical equipment (e.g., induced-draft fans and mechanical draft cooling towers) associated with normal plant operations. Intermittent sources include the equipment related to coal handling, solid waste disposal, transportation related to coal and lime delivery and the commuting of plant employees. The incremental noise impacts of a coal-fired plant compared to HNP are considered to be small to moderate. Further, because of the location of the facility, and the effects of shielding by physical barriers (e.g., coal pile, buildings, intervening trees, or other physical barriers) the effects of noise impacts offsite would be limited.

Coal and lime delivery would be expected to result in some noise impacts on residents living in the vicinity of the facility and along the rail route. Normally coal is delivered and unloaded during daylight hours. The existing rail spur has historically had infrequent use, with smaller unit trains. Delivery of coal and lime would add a new noise source for receptors along the rail corridor. Although noise from passing trains significantly raises noise levels near the rail corridor, the short duration of the noise reduces the impact. Therefore, the impacts of noise on residents in the vicinity of the facility and the rail line would be considered small.

Water Quality and Use

The coal-fired generation alternative is assumed to use the existing HNP intake and discharge structures. However, this alternative would require the withdrawal of roughly half as much water (approximately 30 million gallons per day) for condenser cooling and to meet existing limitations on discharge temperatures. Water quality impacts would continue to be small.

The reduced workforce size (down from 950 to 250) would reduce groundwater withdrawals for potable water use, but additional withdrawals would be needed for wet-scrubber sulfur oxides emissions control. Maximum groundwater consumption is assumed to be 6.1 gallons per minute. Leachate from coal storage areas and ash and scrubber sludge disposal areas would have to be controlled to avoid groundwater contamination.

Air Quality

Concerns over adverse human health effects and environmental effects from coal combustion have lead to important federal legislation such as the Clean Air Act (Reference 10). The following discussion takes these concerns into account.

Sulfur oxides emissions – Using sulfur oxides emissions control provisions that are currently reasonable (low sulfur coal and 90 percent sulfur oxides emissions removal efficiency), the annual stack emissions would include approximately 3,600 tons of sulfur oxides, most of which would be sulfur dioxide. (See Section 2.2.2.1.) Additional reductions could become necessary. The acid rain provision of the Act (Title IV) capped the nation's sulfur dioxide emissions and, under the Act, affected fossil fuel-fired steam units are allocated a number of sulfur dioxide emission allowances. To achieve compliance, each utility must hold enough allowances to cover its sulfur dioxide emissions annually or be subject to certain penalties. If the utility's sulfur dioxide emissions are less than its annually-allocated emission allowances, then the utility may bank the surplus allowances for use in future years. A sulfur dioxide allowances market has been established for the buying and selling of allowances. To build and operate an HNP coal-fired generation alternative beginning in the year 2014, Georgia Power Company would have to purchase sufficient sulfur dioxide allowances for the HNP-alternative plant or increase sulfur dioxide removal efficiency such that purchase of sulfur dioxide allowances is not required.

Nitrogen oxides emissions – Using currently available control technology (low nitrogen oxide burners), annual nitrogen oxides emission would be approximately 1,710 tons. Title IV, however, established an annual nitrogen oxides emissions reduction policy. In addition, EPA has promulgated (September 25, 1998) regulations which require the reduction of nitrogen oxide emissions by 1.1 million tons per year by 2003, or by 28 percent overall by 2007 (Reference 49). [On May 14, 1999, the U.S. Court of Appeals for the District of Columbia Circuit panel ruled that 8-hour standard for ozone was unconstitutional. In addition, on May 25, 1999, the same federal appeals court stayed the EPA's rule to implement the NOx SIP Call. As such, the due date for the NOx SIP Call (or "clean air" plan as it is incorrectly referred to) will be delayed indefinitely.] EPA has indicated it will work with states to develop a market-based emissions trading system for utilities. In order to implement a HNP coal-fired alternative, GPC would have to offset its corporate nitrogen oxides emissions in the state through further reductions in nitrogen oxides emissions elsewhere, by shutting other sources down or by back-fitting to reduce nitrogen oxides formation (e.g., installing over-fired air, low nitrogen oxide burners, flue gas re-circulation, and selective non-catalytic and catalytic reduction systems). Precise reduction requirements are speculative at this time.

Particulate emissions – As stated in Section 2.2.2.1, annual stack emissions would include 240 tons of filterable particulates and 54 tons of PM-10. In addition, coal-handling equipment would introduce fugitive particulate emissions.

Carbon oxides emissions – As stated in Section 2.2.2.1, carbon oxides emissions would be approximately 1,170 tons per year.

Air quality impacts of coal-fired generation would be largely due to sulfur dioxide, nitrogen oxides, particulate, and carbon monoxide emissions. While constituent emissions might have to be reduced more than current projections due to Clear Air Act requirements, the overall impact of a HNP coal-fired alternative would still be large. Siting the coal-fired generation elsewhere would not significantly change air quality impacts, although it could result in installing more or less stringent pollution control equipment to meet applicable standards. The impacts would still be moderate to large.

Coal Combustion By-Products

Coal combustion generates by-products in the form of ash and air pollution control equipment generates additional ash and scrubber sludge. Approximately 1.5 million tons of those by-products would be generated annually for 40 years and disposed of on-site, accounting for 600 of the 900 acres of land use. This is a moderate impact that could extend well after the 40-year operation life because re-vegetation management and groundwater monitoring for leachate contaminant impacts could be a permanent requirement. This impact would be moderate to large. Siting elsewhere would not substantially affect the rate of by-products generation, although other sites might have more constraints on disposal locations.

Human Health/Population Impacts

Coal-fired generation introduces worker risks from fuel and lime/limestone mining and worker and public risks from fuel and lime/limestone transportation and stack emissions inhalation. Stack impacts can be very widespread and health risks difficult to quantify. This alternative also introduces the risk of coal fires and attendant inhalation risks.

Transportation

Coal and Lime Delivery - As discussed in Section 2.2.2.1, approximately 520 trains per year, or an average of 10 trains each week, would deliver the coal and lime for all three units. Since for each full train delivery, there is an empty train, a total of 20 train trips are expected per week, or at least 2.6 trips per day. On several days per week there could be 3 trains per day using the rail spur to the HNP site. Coal and lime delivery would occur during daylight hours.

The Industrial Spur rail line serving the plant is currently not in use, and the Norfolk Southern rail line is used four times per day. Therefore the use of rail for coal/lime delivery would not affect other rail use in the vicinity of the site. The rail line spur from the main railroad to HNP crosses U.S. Highway 341 and U.S. Highway 1, in addition to several county roads (Figure 2-2).

Based on the use of a 115-car coal train with three locomotives, and assuming a speed of 20 miles per hour through the town of Baxley and approaching the site, the affected at-grade crossing intersections are estimated to be blocked for about five minutes per train trip. For two train trips per day, this equates to two separate five minute periods for each highway, separated by the time (4.5 hours)[6] necessary to unload the rail cars at a minimum. As indicated in Section 3.1.14, HNP is located in a mostly rural area and the roads are lightly-traveled. Therefore, two separate 5 minute periods each day are not expected to have a significant effect on vehicular traffic in the area.

Commuting of Plant Operating Personnel - HNP is operated on a continuous basis (i.e., 24 hours per day, every day, except when down time for maintenance, inspection, etc. is required). The maximum number of plant operating personnel would be approximately 220 (Reference 14). The current HNP workforce is approximately 950. Therefore, traffic impacts associated with commuting plant personnel would be expected to be small compared to the current impacts from HNP operations.

Socioeconomics

It is assumed that construction of new coal-fired generating facilities would take place while HNP continues to operate, finishing at the time that the nuclear plant would halt operations. Therefore, for the 5-year construction period, the site would have between 1,500 and 2,000 additional workers. During this time, the surrounding communities would experience demands on housing and public services that could have large impacts. After construction, the communities would be impacted by the loss of jobs; construction workers would leave, the nuclear plant workforce (950) would decline through a decommissioning period to a minimal maintenance size, and the coal-fired plant would introduce only 250 new jobs. Socioeconomic impacts from start of construction through nuclear plant decommissioning would be moderate to large.

Construction at another site would transfer some socioeconomic impacts but would not eliminate them; the community around HNP would still experience the impact of HNP operational job loss,

6. Unloading of rail cars is accomplished at a maximum of 25 cars per hour; therefore, 115 cars per unit train ÷ 25 cars per hour = 4.6 hours. (Reference 14, Section 3.3.4.1)

and the communities around the new site would have to absorb the impacts of a large, temporary workforce and a moderate, permanent workforce.

Cultural Resources

Coal-fired generation at HNP would not directly affect cultural resources. Construction at another site could necessitate instituting cultural resource preservation measures (power block area or transmission line right-of-way), but impacts to cultural resources could generally be managed and kept as small.

Summary of Impacts

Development of a coal-fired generation alternative would produce moderate-to-large air quality impacts, depending on the location of the plant and the effectiveness of air pollution control equipment. Converting 900 acres of forested land to industrial use (generating facility, coal storage area, ash ponds) would produce moderate-to-large land use impacts and could produce moderate-to-large ecological impacts, including wildlife habitat loss, (potential) habitat fragmentation, and a local reduction in biological diversity. Impacts to surface water would be small, assuming coal storage areas and ash/sludge disposal areas were properly configured and monitored to prevent runoff to downgradient wetlands and streams. Impacts to groundwater would be moderate to large, depending on the degree to which contaminants in stored coal, ash, and scrubber sludge are contained and prevented from leaching into underlying groundwater. Socioeconomic impacts would be moderate to large, and would include pressures on housing and public services during the construction phase (from an influx of construction workers) and a reduction in operational jobs (net loss of approximately 700 jobs) relative to the existing HNP workforce.

3.2.3 Gas-Fired Generation

Land Use

Gas-fired generation at the HNP site would require converting an additional 500 acres of the site to industrial use. Currently, this land is mostly forested. These changes would noticeably alter current HNP land use patterns and would create moderate impacts. An additional 121 acres would be disturbed during pipeline construction but, because this disturbance would be temporary and would not alter existing land use patterns (access road right-of-way and cultivation), these land use impacts from pipeline construction would be small.

Construction at a new site would impact another approximately 100 acres for offices, roads, parking areas, and a switchyard, and another 300 acres for transmission lines. Depending particularly on transmission line routing, these alternatives could result in moderate to large land use impacts.

Ecology

Siting at the existing HNP site would have a moderately large to large ecological impact because of the need to convert roughly 500 acres of established forested land to industrial use. However, use of the existing intake and discharge system to which the area aquatic communities in the Altamaha River have become acclimated would limit operational impacts.

Even at an existing power plant site, adding the HNP alternative gas-fired generation would introduce construction impacts and new incremental operational impacts. At a greenfield site, an undisturbed area, the impacts would certainly alter the ecology. These ecological impacts could be moderate to large. Impacts would include wildlife habitat loss and reduced productivity, and could include habitat fragmentation and a local reduction in biological diversity.

Aesthetics

The combustion turbines and heat recovery boilers would be relatively low structures, less than 100 feet tall, and would be screened from most offsite vantage points by intervening woodlands. The steam turbine building would be taller, approximately 150 feet in height, and together with the exhaust stacks (230 feet in height), would be visible offsite, resulting in a moderate impact. The use of these facilities along with the existing mechanical draft cooling towers and associated facilities, would have less visual impact than the existing HNP reactor building and stack which are considerably taller (200 feet and 393 feet tall respectively).

Water Quality

The gas-fired generation alternative is assumed to use the existing HNP intake and discharge structures. However, this alternative would require the withdrawal of roughly one-fourth as much water (approximately 15 million gallons per day) for condenser cooling and meet existing limitations on discharge temperatures. Water quality impacts would continue to be small. The reduced workforce size (950 to 125) would reduce groundwater withdrawals for potable water use; however, the existing groundwater impact is already small (Section 3.1.3).

Air Quality

Natural gas is a relatively clean-burning fuel. Nitrogen oxide emissions, assuming low nitrogen oxide burners, would be 386 tons per year; by comparison, nitrogen oxide emissions assuming flue gas re-circulation would be 290 tons per year. As discussed in Section 3.2.2 for coal-fired generation, new Clean Air Act provisions might result in SNC having to further reduce nitrogen oxides by shutting other sources down or by back-fitting to reduce nitrogen oxides formation (e.g., installing over-fired air, low nitrogen oxide burners, flue gas re-circulation, and selective non-catalytic and catalytic reduction systems). Precise reduction requirements are speculative at this time.

Gas Combustion By-Products

Gas-fired generation would result in almost no by-product generation, producing impacts that are small.

Human Health

Gas-fired generation would produce combustion emissions, but impacts to human health would be small due to the clean-burning nature of the natural gas fuel.

Socioeconomics

It is assumed that construction of new gas-fired generating facilities would take place while HNP continues operation, with completion at the time that the nuclear plant would halt operations. Therefore, for the 3-year construction period, the site would have between 500 and 750 additional workers. During this time, the surrounding communities would experience demands on housing and public services that could have large impacts. After construction, the communities would be impacted by the loss of jobs; construction workers would leave, the nuclear plant workforce (of 950 workers) would decline through a decommissioning period to a minimal maintenance size, and the gas-fired plant would introduce only 125 new jobs. Socioeconomic impacts from start of construction through nuclear plant decommissioning would be moderate to large.

Construction at another site would transfer some socioeconomic impacts but would not eliminate them. The community around the HNP site would still experience the impact of HNP operational job loss, and the communities around the new site would have to absorb the impacts of a large, temporary workforce and a moderate, permanent workforce.

Transportation

As indicated above, the HNP workforce (of 950 workers) would decline and the gas-fired plant would introduce only 150 new jobs. Therefore, traffic impacts associated with commuting plant personnel would be expected to be less than the current impacts from HNP operations

Cultural Resources

Gas-fired generation at HNP would not directly affect cultural resources. Construction at another site could necessitate instituting cultural resource preservation measures (power block area or transmission line right-of-way), but impacts to cultural resources could generally be managed and kept as small.

Summary of Impacts

Development of a gas-fired generation alternative would require converting approximately 500 acres of forested land to industrial use and could produce moderate-to-large land use and ecological impacts. Impacts to surface water and groundwater would be small. Air quality impacts would be small, assuming state-of-the-art pollution control equipment is installed and operated as designed. Socioeconomic impacts would be moderate to large, and would include pressures on housing and public services during the construction phase (from an influx of construction workers) and a reduction in operational jobs (net loss of approximately 800 jobs) relative to the existing HNP workforce.

3.2.4 Imported Electrical Power

As discussed in Section 2.2.2.3, Georgia is a net exporter of electric power. However, SNC cannot discard imported power as a feasible alternative to HNP license renewal. Market conditions, particularly the anticipated free market created by deregulation, could result in a company finding it advantageous to import power to replace a retired Georgia plant while exporting other power generated in state. Such a situation could be caused by differential costs of generation or transmission, contractual relationships, or even strategic planning.

SNC assumes that if it did import power to replace HNP-generated capacity, the power would be generated elsewhere using one or more of the technologies that NRC discusses in GEIS Chapter 8. SNC has no basis for estimating which generation technology, or what mix of technologies, would be used other than to point to the current mix of technologies available. The U.S. Department of Energy publications that SNC references in Section 2.2.2.3 are excellent sources of information on this subject.

SNC is adopting by reference, as representative of the environmental impacts of the imported electrical power alternative to HNP license renewal, the GEIS discussion of environmental impacts from generic alternatives. Under the imported power alternative, therefore, environmental impacts would still occur but would be located elsewhere within the region, nation, or Canada.

3.3 COMMITTED RESOURCES

3.3.1 Unavoidable Adverse Impacts

> ***NRC***
>
> ***The environmental report shall discuss ". . . [a]ny adverse environmental effects which cannot be avoided should the proposal be implemented." [10 CFR 51.45(b)(2) as referenced in 10 CFR 51.53(c)(2)]***

Section 3.1 adopts by reference the GEIS discussion of Category 1 issues, a discussion that addresses adverse environmental effects. For Category 2 issues, HNP has followed NRC regulatory requirements, analyzed the issues, and where required has addressed potential adverse effects (in Section 3.1). For the applicable issues presented in Section 3.1, SNC has categorized all impacts as "small" in accordance with NRC's impact significance definitions. NRC defines small as an effect that is either not detectable or so minor that it will neither destabilize nor noticeably alter any important attribute of the resource. SNC assumes that impacts that are "small" by this definition are not adverse, and that, therefore, the environmental report has identified no unavoidable adverse impacts.

3.3.2 Irreversible or Irretrievable Resource Commitments

> ***NRC***
>
> ***The environmental report shall discuss ". . . [a]ny irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented." 10 CFR 51.45(b)(5) as referenced in 10 CFR 51.53(c)(2)***

HNP generates approximately 250 assemblies of spent fuel per year. Operation during the license renewal period would generate approximately 5,000 assemblies of spent fuel. This spent fuel is destined for disposal at the nation's high-level radioactive waste geologic repository, currently planned for construction at Yucca Mountain, Nevada. This activity is considered to be an irreversible and irretrievable commitment of the material in the spent fuel assemblies and the repository space in which the assemblies would be placed. The NRC has analyzed the radiological impacts of this disposal activity and has concluded that it is a Category 1 issue (10 CFR Part 51, Subpart A, Appendix B, Table B-1).

The NRC evaluated fish and shellfish mortality due to impingement and entrainment and concluded that the issue did not warrant further analysis at plants using cooling towers for heat dissipation. While mortality from impingement and entrainment would be an irreversible and irretrievable commitment of small numbers of fish and shellfish, this is an on-going impact from HNP operations and no irreversible or irretrievable impacts on fish or shellfish populations (population-level effects) in the Altamaha River have been shown.

3.4 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY

> ***NRC***
>
> ***The environmental report shall discuss ". . . [t]he relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity. . . ." 10 CFR 51.45(b)(4) as referenced in 10 CFR 51.53(c)(2)***

HNP operation during the license renewal period would result in the short-term resource uses described in Section 3.1, including those described in the GEIS and adopted by reference in Section 3.1. As a result of normal operations, short-term uses of the atmosphere, surface waters, and land surface as receptors for emissions, discharges, and wastes would have an incremental but small effect on long-term air, water, and land conditions. SNC has not identified any clear indication of adverse impacts on long-term productivity in the area. Ongoing efforts to restore the longleaf pine-wiregrass community on the HNP site are expected to enhance long-term productivity of at least two listed species, the gopher tortoise and the Eastern indigo snake.

Table 3-1 Local aquifers to E.I. Hatch Nuclear Plant

Geologic age	Aquifer	Description	Physical description	Water-bearing properties	Formation thickness at Hatch (feet)	Approximate aquifer elevation at Hatch (feet msl)
Holocene	Alluvial	Alluvium beneath the Altamaha River floodplain	Sand, gravel, and carbonaceous silty clay	Potential for high yields	55	Less than +75
Pliocene (?) to Pleistocene	Perched	Brandywine Formation	Sand and gravel	No values recorded	10	+165 to +175
Miocene	Unconfined	Upper Hawthorn	Clayey sand	Less 10 gpm	45 to 50	+165 to +170
Miocene	Confining Unit	Upper Hawthorn	Sandy clay and clay with locally cemented sand	Relatively impermeable	40 to 50	+100 to +120
Miocene	Minor Confined	Middle Hawthorn	Sand and clayey sand	10 gpm	65	0 to +65
Miocene	Confining Unit	Lower Hawthorn	Sandy clay	Permeability of 1 x 10^{-7} ft/min	100 to 110	0
Miocene	Principal Artesian (Floridan)	Extreme Lower Hawthorn Formation	Sandy limestone and calcareous clayey sand	1100gpm in properly designed well	190	-105
Miocene	Principal Artesian (Floridan)	Tampa Formation	Sandy limestone and calcareous clayey sand		160	
Oligocene	Principal Artesian (Floridan)	Suwanee Formation (Undifferentiated ?)	Limestone		120(?)	
Eocene	Principal Artesian (Floridan)	Ocala Formation	Limestone		280	
Eocene	Principal Artesian (Floridan)	Lisbon Formation	Sandy limestone and calcareous clayey sand		610	

a. Source: Reference 32.

Table 3-2 Listed species known to occur in the vicinity of HNP or in associated rights-of-way.

Common Name	Scientific Name	Federal Status	State Status	Occurrence	Source
Shortnose sturgeon	*Acipenser brevirostrum*	Endangered	Endangered	Altamaha R. adjacent to HNP	Reference 5
Eastern indigo snake	*Drymarchon corais couperi*	Threatened	Threatened	North Tifton transmission corridor	Reference 65
Gopher tortoise	*Gopherus polyphemus*	---	Threatened	HNP site; Duval, North Tifton, Douglas, Thalmann, Bonaire, and Vidalia transmission corridors	References 5, 54, 65
American alligator	*Alligator mississippiensis*	Threatened (S/A)	---	HNP site; Bonaire, North Tifton, and Thalmann transmission corridors	References 3, 65
Bald eagle	*Haliaeetus leucocephalus*	Threatened	Endangered	Altamaha R. adjacent to HNP	(b)
Wood stork	*Mycteria americana*	Endangered	Endangered	Wetland east of HNP cooling towers	(b)
Red-cockaded woodpecker	*Picoides borealis*	Endangered	Endangered	Duval transmission corridor[c]	Reference 65, 66
Bachman's sparrow	*Aimophila aestivalis*	---	Rare	Duval and Thalmann transmission corridors	References 65, 66
Purple honeycomb head	*Balduina atropurpurea*	---	Rare	Duval, North Tifton, and Vidalia transmission corridors	Reference 65
Cutleaf beardtongue	*Penstemon dissectus*	---	Threatened	Thalmann transmission corridor	References 65, 66
Hairy rattleweed	*Baptisia arachnifera*	Endangered	Endangered	Thalmann corridor	Reference 66
Parrot pitcher plant	*Sarracenia psittacina*	---	Threatened	Duval and North Tifton transmission corridors	References 65, 66
Yellow pitcher plant	*Sarracenia flava*	---	Unusual	HNP site; Bonaire, Thalmann, North Tifton, and Vidalia transmission corridors	References 65, 66
Hooded pitcher plant	*Sarracenia minor*	---	Unusual	Bonaire, Duval, Thalmann, Tifton, and Vidalia transmission corridors	References 65, 66

a. Species that USFWS or NMFS has listed or proposed for listing as threatened or endangered; species that GADNR has listed or proposed for listing as endangered, threatened, rare, or unusual.
b. Observed by Georgia Power Company biologists.
c. Observed in wooded area adjacent to right-of-way.

Table 3-3. Estimated population distribution in 1990 within 10 miles of HNP.[a]

Sector[b]	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile total
N	0	10	26	0	81	378	495
NNE	0	1	0	0	6	280	287
NE	0	0	0	15	27	259	301
ENE	0	0	0	0	3	108	111
E	0	0	0	0	22	23	45
ESE	0	0	34	0	0	229	263
SE	0	0	19	12	45	275	351
SSE	0	0	38	24	122	428	612
S	0	21	137	53	46	1,900	2,157
SSW	0	27	82	62	32	313	516
SW	0	55	23	15	9	218	320
WSW	0	0	32	0	14	372	418
W	0	72	0	128	0	103	303
WNW	0	0	0	38	0	324	362
NW	0	0	0	8	21	384	413
NNW	0	2	95	70	40	343	550
Total	0	188	486	425	468	5,937	7,504

a. Source: Reference 50.

Table 3-4. Estimated population distribution in 1990 within 50 miles of HNP.[a]

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile total
N	495	10,706	4,375	1,239	11,652	28,525
NNE	287	1,007	1,932	6,657	5,207	15,090
NE	301	3,812	2,833	2,505	29,497	38,948
ENE	111	3,008	4,120	3,916	5,369	16,524
E	45	748	6,868	1,348	38,160	47,169
ESE	263	448	1,278	3,538	8,931	14,458
SE	351	275	2,002	15,477	881	18,986
SSE	612	922	1,221	3,880	2,446	9,081
S	2,157	6,646	1,693	1,983	32,090	44,569
SSW	516	1,210	6,203	2,758	2,193	12,880
SW	320	1,457	1,113	5,178	18,479	26,547
WSW	418	7,510	1,041	2,262	2,407	13,638
W	303	2,156	1,654	1,407	2,682	8,202
WNW	362	585	2,308	6,376	2,721	12,352
NW	413	1,335	4,589	985	4,347	11,669
NNW	550	4,351	3,802	5,250	4,040	17,993
Total	7,504	46,176	47,032	64,817	171,102	336,631

a. Source: Reference 50.

Table 3-5. Appling County land use characterization.[a]

Landuse category	Acres	Percent of county
Agriculture	109,276	32.6
Forest/Mining	167,364	50.0
Residential	3,626	1.1
Commercial	373	0.1
Industrial	738	0.2
Public/Semi-Public	421	0.1
Recreation/Park/Open Space	202	0.1
Vacant/Undeveloped	52,862	15.8
Total	334,862	100

a. Source: Reference 46.

Table 3-6. Tax payment amounts for the Edwin I. Hatch Plant, Appling County, Georgia, 1994–1998.

	1994	1995	1996	1997	1998
Appling County Digest[b]	$10,025,813.94	$10,061,773.42	$11,470,528.89	$11,577,951.81	$12,421,866.50
Georgia Power	$4,228,927.15	$4,108,164.72	$4,515,508.42	$4,470,276.95	$4,616,865.29
Oglethorpe Power	$3,043,071.08	$3,048,859.27	$3,496,434.75	$3,468,656.36	$3,717,624.25
City of Dalton	$158,141.15	$157,236.19	$157,592.66	$142,766.76	$149,999.51
Total HNP tax payment	$7,430,139.38	$7,314,260.18	$8,169,535.83	$8,081,700.07	$8,484,489.05
HNP percent of County Digest	74 percent	73 percent	71 percent	70 percent	68 percent

a. Source: Reference 51.
b. The "Digest" is the total property tax revenue that the County collects, portions of which are reserved for use by local governing bodies (e.g., school board) and for use by the State within the County boundaries.

Table 3-7. Census tracts with minority populations.[a]

			Percent						
Census tract	County	Pop. 1990	White	Black	Indian	Asian	Other	Hispanic	Minority
13001950200	Appling	4,292	47.9	51.6	0.5	0.0	0.0	0.0	52.1
13031990800	Bulloch	1,644	57.2	39.9	0.7	0.9	0.4	1.0	42.9
13043950200	Candler	964	58.1	41.9	0.0	0.0	0.0	0.0	41.9
13069990800	Coffee	6,972	53.1	46.6	0.1	0.1	0.0	0.1	46.9
13107980400	Emanuel	4,338	59.0	40.7	0.0	0.1	0.0	0.2	41.0
13107980100	Emanuel	4,308	61.2	38.6	0.1	0.0	0.0	0.1	38.8
13109970300	Evans	3,466	55.2	44.7	0.0	0.1	0.0	0.0	44.8
13179010100	Liberty	16,340	49.5	39.1	0.9	2.4	0.3	7.7	50.4
13179010200	Liberty	16,878	54.1	37.4	0.1	2.3	0.2	6.0	46.0
13267990298	Tattnall	7,284	58.9	37.9	0.2	0.1	0.2	2.7	41.1
13271950400	Telfair	2,019	55.3	44.4	0.0	0.0	0.0	0.3	44.7
13271950300	Telfair	930	60.3	39.4	0.3	0.0	0.0	0.0	39.7
13279970200	Toombs	5,563	56.1	42.6	0.1	0.0	0.0	1.2	43.9
13299950400	Ware	3,147	10.3	87.9	0.3	1.1	0.0	0.4	89.7

a. Source: Reference 40.

Table 3-8. Census Tracts with Low-Income Populations[a]

Census tract (FIPS#)	County name	County (FIPS#)	1990 Population	Households	Households above poverty level	Households below poverty level	Percent Households above poverty level	Percent Households below poverty level
13001950200	Appling	001	4,292	1,527	1,082	445	70.9	29.1
13001950400	Appling	001	1,640	610	450	160	73.8	26.2
13005970200	Bacon	005	6,999	2,542	1,774	768	69.8	30.2
13043950200	Candler	043	964	338	250	88	74.0	26.0
13069990700	Coffee	069	4,433	1,503	1,117	386	74.3	25.7
13069990800	Coffee	069	6,972	2,447	1,792	655	73.2	26.8
13107980400	Emanuel	107	4,338	1,578	1,041	537	66.0	34.0
13107980700	Emanuel	107	784	301	199	102	66.1	33.9
13109970300	Evans	109	3,466	1,234	855	379	69.3	30.7
13161960200	Jeff Davis	161	5,122	1,946	1,443	503	74.2	25.8
13209950200	Montgomery	209	4,028	1,366	994	372	72.8	27.2
13229960200	Pierce	229	1,366	436	321	115	73.6	26.4
13229960300	Pierce	229	4,911	1,870	1,333	537	71.3	28.7
13267990100	Tattnall	267	2,736	1,148	836	312	72.8	27.2
13267990300	Tattnall	267	3,624	1,341	947	394	70.6	29.4
13271950100	Telfair	271	6,443	2,379	1,718	661	72.2	27.8
13271950200	Telfair	271	1,608	600	421	179	70.2	29.8
13271950400	Telfair	271	2,019	708	478	230	67.5	32.5
13271950300	Telfair	271	930	335	233	102	69.6	30.4
13279970200	Toombs	279	5,563	1,795	1,208	587	67.3	32.7
13279970100	Toombs	279	4,153	1,414	959	455	67.8	32.2
13283960298	Treutlen	283	5,182	1930	1,354	576	70.2	29.8
13299950100	Ware	299	1,354	459	329	130	71.7	28.3
13299950400	Ware	299	3,147	1,284	612	672	47.7	52.3
13305970300	Wayne	305	5,130	1,867	1,323	544	70.9	29.1
13305970400	Wayne	305	2,598	921	641	280	69.6	30.4
13309980100	Wheeler	309	2,414	904	603	301	66.7	33.3
13309980200	Wheeler	309	2,489	916	658	258	71.8	28.2

a. Source: Reference 40.

Table 3-9. County population data.[a]

		Percent							
County	Total Population	White	Black	American Indian, Eskimo, or Aleut	Asian	Other	Hispanic Origin	Households below the Poverty Level	Minority
Appling	15,744	78.56	20.76	0.35	0.00	0.00	0.33	22.35	21.44
Bacon	9,566	83.46	15.42	0.11	0.05	0.00	0.95	27.12	16.54
Bulloch	5,890	74.97	24.21	0.20	0.24	0.10	0.27	18.39	25.03
Candler	7,744	67.12	30.94	0.00	0.23	0.00	1.70	23.59	32.88
Coffee	26,739	72.39	25.51	0.11	0.43	0.03	1.53	23.69	27.61
Dodge	2,006	73.18	26.72	0.00	0.00	0.00	0.10	21.19	26.82
Emanuel	15,566	68.25	30.68	0.20	0.60	0.00	0.27	26.42	31.75
Evans	8,724	65.02	33.73	0.02	0.08	0.00	1.15	26.33	34.98
Jeff Davis	12,032	83.85	15.36	0.05	0.00	0.00	0.74	21.05	16.15
Johnson	1,418	84.49	15.44	0.00	0.00	0.00	0.07	18.38	15.51
Laurens	10,800	78.67	21.26	0.07	0.00	0.00	0.00	20.92	21.33
Liberty	33,218	51.84	38.23	0.52	2.38	0.23	6.81	13.57	48.16
Long	3,104	76.19	18.65	0.45	0.55	0.00	4.16	20.44	23.81
Montgomery	7,163	69.55	28.17	0.08	0.20	0.00	2.00	25.01	30.45
Pierce	13,328	87.52	11.69	0.12	0.00	0.00	0.67	23.88	12.48
Tattnall	17,722	68.15	28.94	0.13	0.12	0.08	2.58	23.55	31.85
Telfair	11,000	65.41	34.44	0.03	0.00	0.00	0.13	29.14	34.59
Toombs	24,072	72.96	23.38	0.27	0.39	0.00	3.00	24.78	27.04
Treutlen	5,994	66.68	33.10	0.13	0.00	0.00	0.08	27.88	33.32
Ware	22,374	74.56	24.21	0.25	0.60	0.00	0.38	19.22	25.44
Wayne	19,750	77.38	21.49	0.07	0.14	0.00	0.93	22.44	22.62
Wheeler	4,903	68.73	30.06	0.00	0.00	0.00	1.20	30.71	31.27
GA Total	6,478,216	70.23	26.83	0.23	1.11	0.04	1.56	14.85	29.77

b. Source: Reference 40.

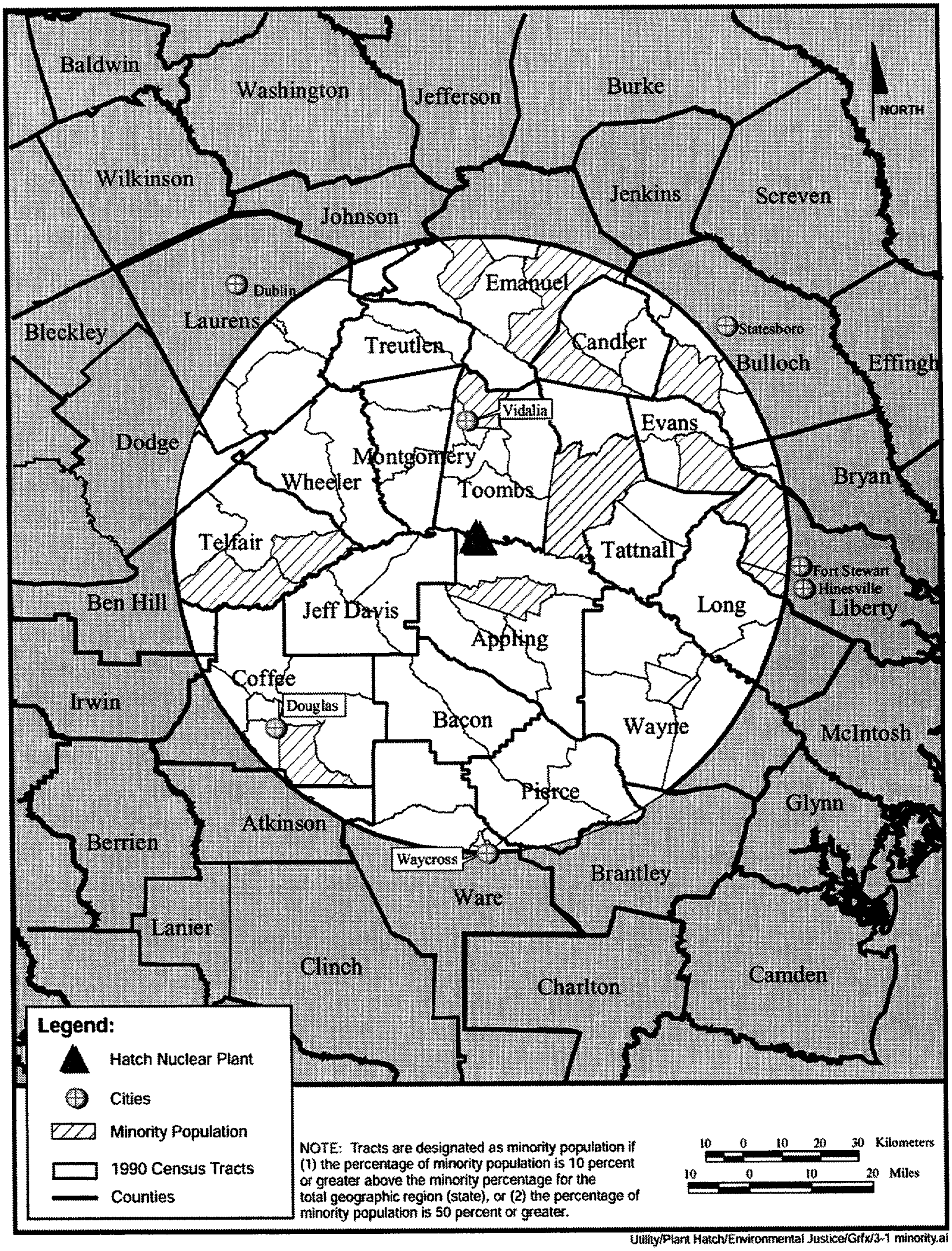


Figure 3-1. Minority population within 50 miles of Edwin I. Hatch Nuclear Plant Site

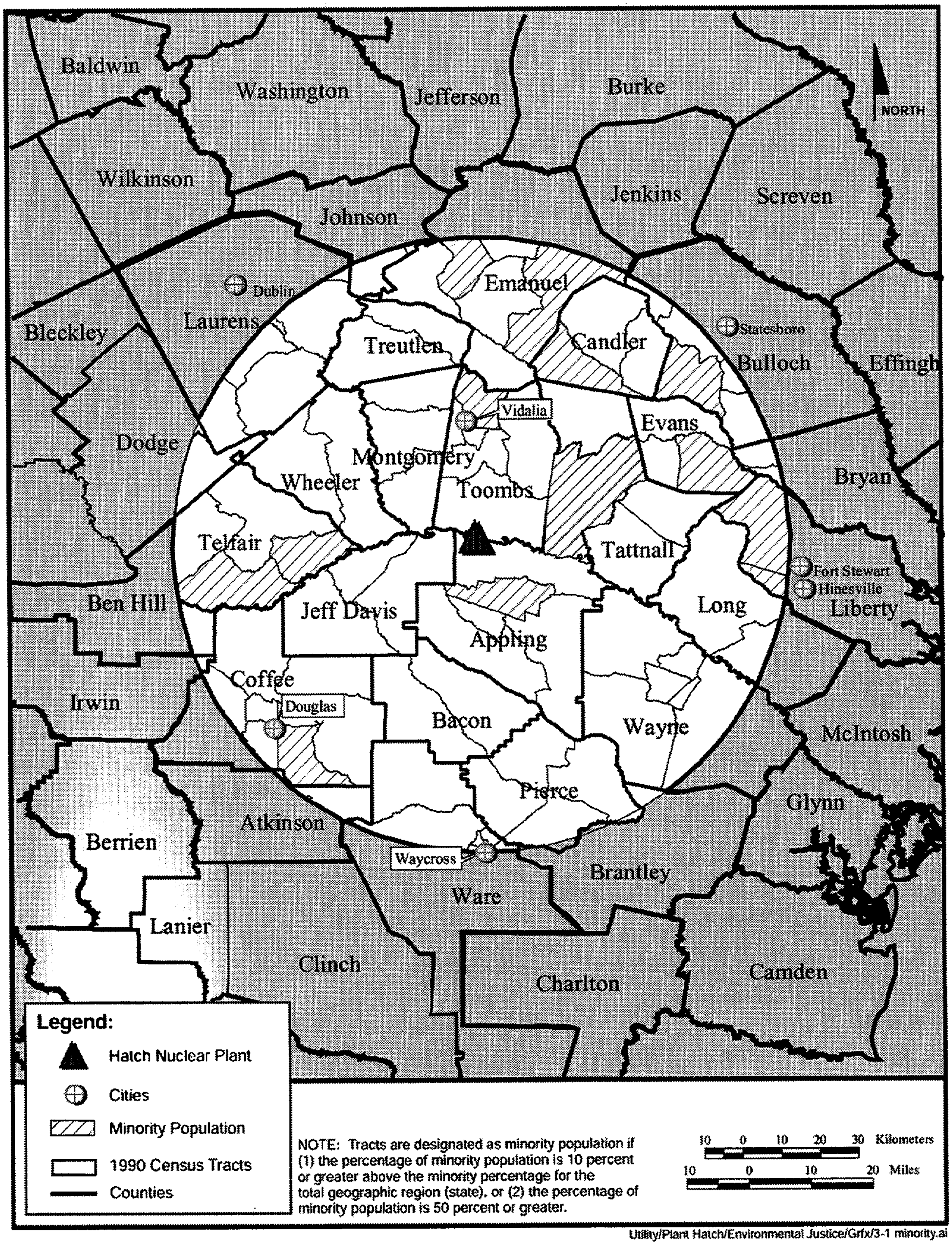
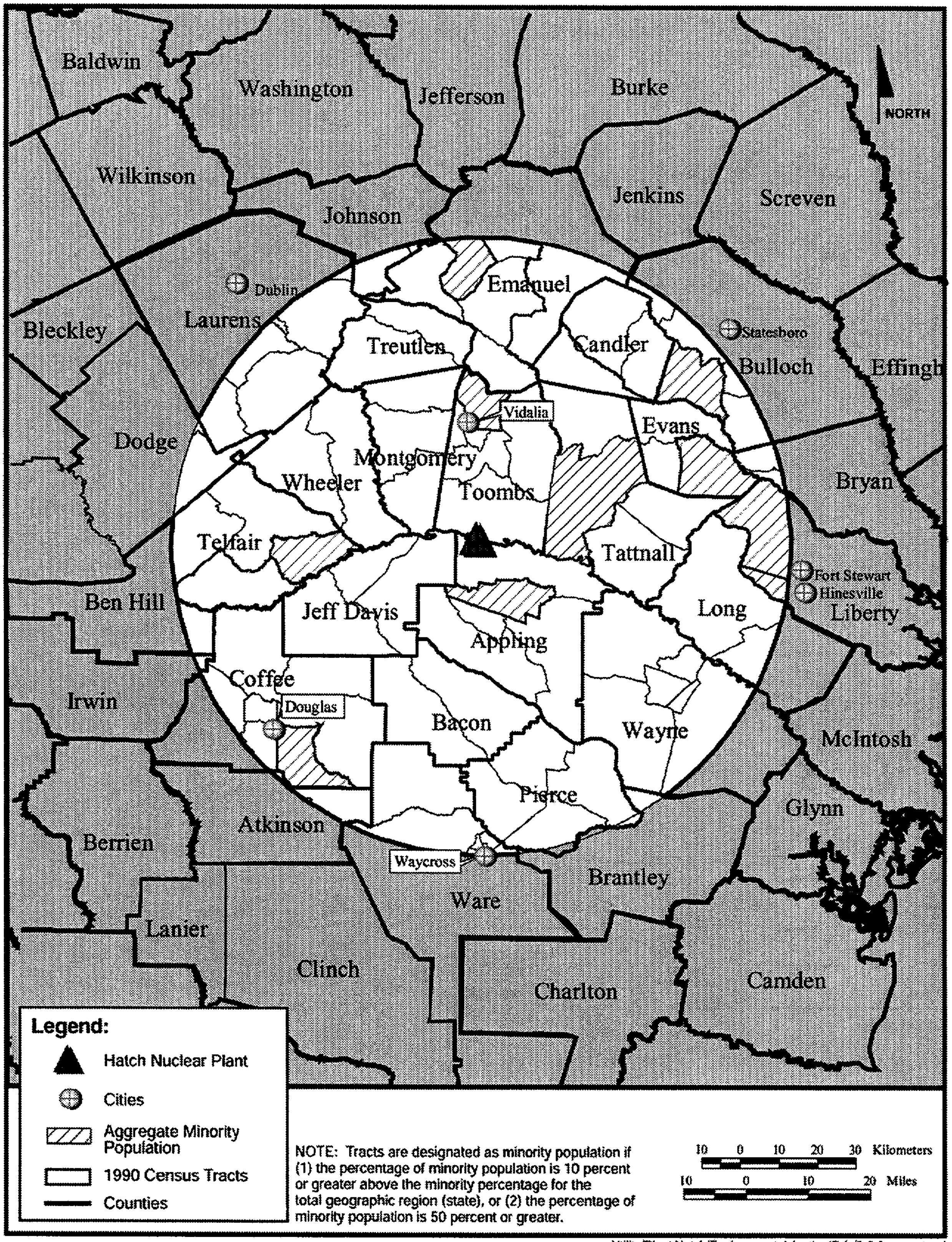


Figure 3-2. Black minority population within 50 miles of Edwin I. Hatch Nuclear Plant Site



Utility/Plant Hatch/Environmental Justice/Grfx/3-2 Aggregate.ai

Figure 3-3. Aggregate minority population within 50 miles of Edwin I. Hatch Nuclear Plant Site

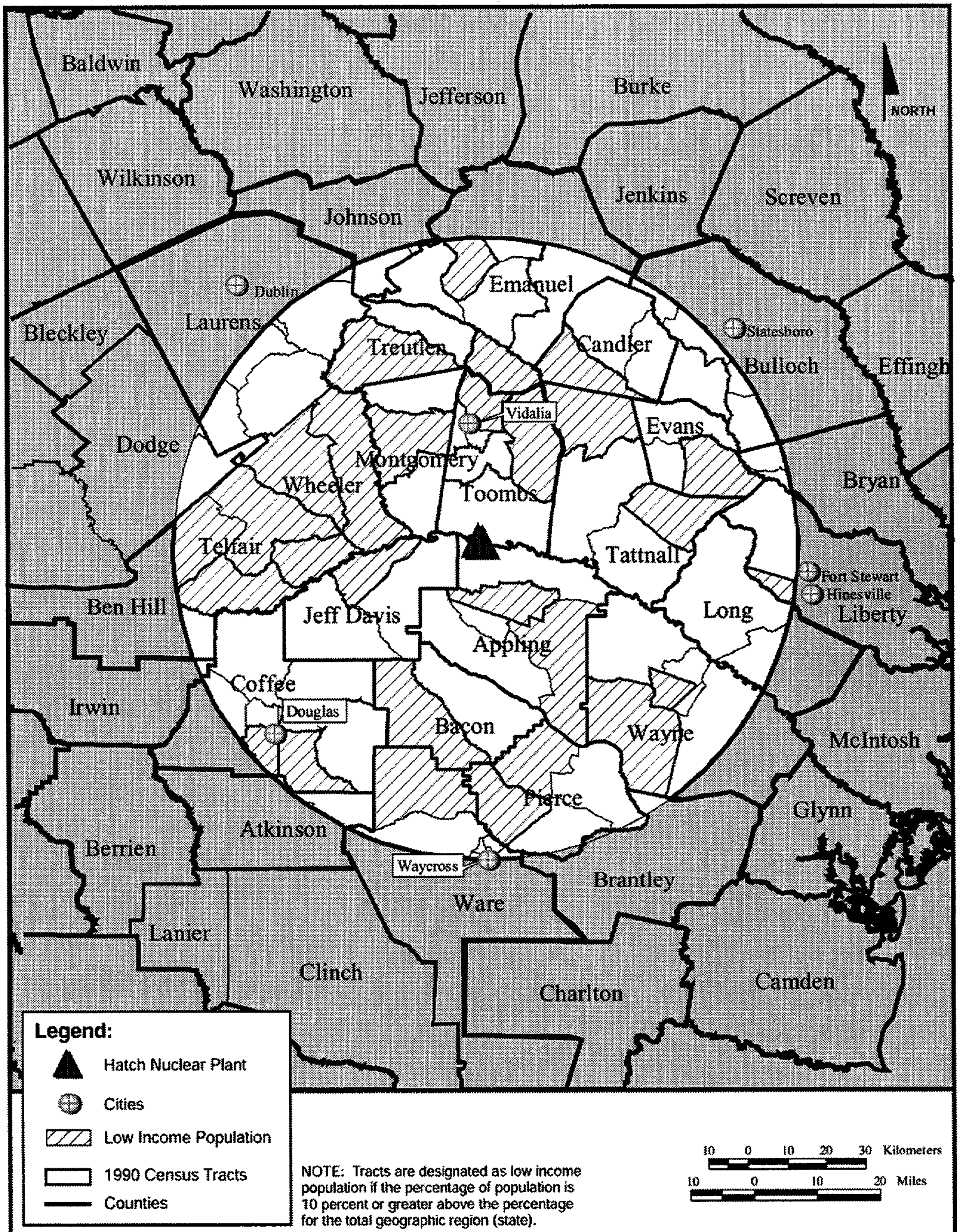


Figure 3-4. Low income population within 50 miles of Edwin I. Hatch Nuclear Plant Site

4.0 COMPLIANCE STATUS

4.1 PROPOSED ACTION

4.1.1 General

Environmental protection licenses and permits from Federal and State authorities for current HNP operations are listed in Table 4-1. HNP has no regionally or locally issued environmental permits or other environmental protection approvals or entitlements. Table 4-2 identifies environmental approvals and consultation associated with HNP license renewal. As indicated, SNC anticipates that relatively few such approvals are required.

SNC has initiated consultation with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service in accordance with Section 7 of the Endangered Species Act (16 USC 1536). SNC has included as Attachment C correspondence related to these consultations.

SNC has initiated consultation with the Georgia State Historical Preservation Officer regarding potential effects of HNP License Renewal on cultural resources, in accordance with Section 106 of the Natural Historic Preservation Act (16 USC 470 et seq.). SNC has included as Attachment D correspondence related to these consultations.

No permits from, or consultations with, states other than Georgia are necessary because HNP is at least 75 miles from the nearest Georgia border and SNC expects that the quality of the water and air in neighboring states would not be affected by the proposed action of license renewal.

4.1.2 Water Quality Certification

E. I. Hatch Nuclear Plant currently holds a National Pollution Discharge Elimination System (NPDES) Permit issued in 1997 by the State of Georgia Department of Natural Resources - Environmental Protection Division. The permit (GA0004120), which was issued in accordance with Section 402 of the Federal Clean Water Act, authorizes water discharges from HNP into the Altamaha River. HNP also holds two permits issued by the U.S. Army Corps of Engineers, Savannah District under Clean Water Act Section 404. One permit (9400003873) authorizes maintenance dredging activities in the Altamaha River in front of the HNP intake structure. The other permit (970012880) authorizes a weir to be constructed in the Altamaha River in front of the Plant Hatch intake structure during low river flow periods, if necessary. Each of the above referenced permits will be maintained, as necessary, throughout operation of the HNP.

Federal Clean Water Act Section 401 requires that applicants for a Federal license to conduct an activity that might result in a discharge into navigable waters must provide the licensing agency a certification from the State that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). SNC is applying to NRC for a license (i.e., license renewal) to continue HNP operations and HNP operations result in discharges to the Altamaha River, a navigable water, within the State of Georgia. At present, HNP holds a Section 401 Water Quality Certification per letter dated November 10, 1972 from the State of Georgia, that issued its approval for HNP relative to water quality.

4.1.3 Coastal Zone Management

The Coastal Zone Management Act of 1972 (16 USC 1451 et seq.) requires applicants for a Federal license to conduct an activity that could affect a state's coastal zone to certify to the licensing agency that the proposed activity would be consistent with the state's Federally-approved coastal zone management plan [16 USC 1456(c)(3)(A)]. The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate the requirement is applicable to renewal of Federal licenses for activities not previously reviewed by the State [15 CFR 930.51(b)(1)]. The regulation requires license applicants to provide its certification to the Federal licensing agency and a copy to the applicable State agency [15 CFR 930.57(a)].

The Georgia Coastal Zone Management Act, enacted in 1997, defines the coastal zone as "all tidally influenced waters and submerged land seaward to the state's jurisdictional limits and all lands, submerged lands, waters, and other resources within the counties of Brantley, Bryan, Camden, Charlton, Chatham, Effingham, Glynn, Long, Liberty, McIntosh, and Wayne counties." The western boundary of Wayne County, which is the portion of the Georgia coastal zone nearest to HNP, is approximately 25 river miles downstream of Hatch Nuclear Plant. Ongoing HNP plant release and environmental monitoring have identified no significant impacts to the environment and no direct impacts on the coastal zone. License renewal would introduce no significant operational changes and SNC license renewal analysis has identified no significant changes to the current level of environmental impacts. Based on the distance to the coastal zone, past HNP performance with respect to discharges and releases, and the fact that no major changes in operations are expected during the license renewal term, SNC believes that direct impacts to the coastal zone from HNP operations during the license renewal term are unlikely. Because HNP is not located within the coastal zone and HNP operations are unlikely to directly affect the coastal zone, requirements for coastal zone management consistency certification are inapplicable to HNP license renewal.

4.2 ALTERNATIVES

NRC

The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements. [10 CFR 51.45(d) as referenced by 10 CFR 51.53(c)(2)]

The coal-fired and gas-fired generation alternatives discussed in Sections 2.2.2.1 and 2.2.2.2, respectively, generally could be designed and constructed at the Plant Hatch location so as to comply with all applicable environmental quality standards and requirements.

Although construction and operation details for the imported power alternative, Section 2.2.2.3, are not known, it is reasonable to assume that any facility offering power for purchase would be in compliance or would be working to achieve compliance.

Table 4-1. Federal, state, local, and regional licenses, permits, consultations, and other approvals pertinent to current HNP Station operation (page 1 of 2).

Agency	Authority	Requirements	HNP Number	Issue Date	Expiration Date	Remarks
COE	Federal Clean Water Act (Section 404)	Maintenance Dredging Permit	940003870	03/19/95	09/31/04	The permit authorizes periodic dredging in the Altamaha river at the HNP intake structure.
COE	River and Harbor Act (Section 10) Clean Water Act (Section 404)	Permit for construction of a Weir	199101536	04/08/93	02/01/03	The permit authorizes construction of a temporary water retaining wall structure (weir) in the Altamaha River near the HNP intake structure. The weir would be placed in the river on in the event of an extreme low flow situation in the river, after supplemental flows from upstream reservoirs are near exhaustion.
GADNR	Georgia Groundwater Use Act, (Georgia Laws 1972 et seq., as amended by Georgia Laws 1973, et seq.)	State Groundwater Use Permit	001-0001	12/16/97	12/04/04	The permit authorizes withdrawal of groundwater from 4 wells for use at HNP sanitary facilities, process water, central water supply, and make-up water for a wildlife habitat pond
GADNR	Georgia Water Quality Control Act, (Georgia Law 1964, et seq.)	State Surface Water Withdrawal Permit	001-0690-01	12/16/97	01/01/10	Permit authorizes withdrawal of surface water from the Altamaha for cooling water at HNP.
EPA; GADNR	Federal Clean Water Act (33 USC 1251 et seq.); Georgia Water Quality Control Act, (Georgia Law 1964, et seq.)	Individual Discharge Permit	GA 0004120	09/15/97	08/31/02	Permit contains effluent limits for HNP combined plant waste steams, including sanitary wastewater, cooling water, and cooling tower blow down. SNP would have to submit a renewal application to GADNR no later than 180 days beyond the expiration date to receive authorization to discharge beyond the expiration date of August 31, 2002.
EPA; GADNR	Federal Clean Water Act (33 USC 1251 et seq.); Georgia Water Quality Control Act, (Georgia Law 1964, et seq.)	Stormwater Discharge Permit	GAR000000	06/01/98	05/31/03	The permit covers all discharges of storm water associated with industrial activities. SNC would have to notify GADNR before new storm water discharges from sites where industrial activity will occur.

Table 4-1. Federal, state, local, and regional licenses, permits, consultations, and other approvals pertinent to current HNP Station operation (page 2 of 2).

Agency	Authority	Requirements	HNP Number	Issue Date	Expiration Date	Remarks
EPA; GADNR	Federal Safe Drinking Water Act [42 USC 300(F) et seq., 40 CFR Parts 100-149]; Georgia Safe Drinking Water Act of 1997, Chapter 391-3-5	Public water system, production	PG0010005	03/21/91	03/21/01	The permit authorizes withdrawal of groundwater from 2 wells for use as drinking water at HNP.
EPA; GADNR	Federal Safe Drinking Water Act [42 USC 300(F) et seq., 40 CFR Parts 100-149]; Georgia Safe Drinking Water Act of 1997, Chapter 391-3-5	Public water system, recreation site	NG0010011	02/07/95	02/06/05	The permit authorizes withdrawal of groundwater from one well for use at the HNP recreation area.
EPA; GADNR	Resource Conservation and Recovery Act (Solid Waste Disposal Act) (42 USC 6901 et seq.); Georgia Solid Waste Management Act, Section 1486, Georgia Laws of 1972 as amended, Chapter 391-3-4	Solid waste landfill, phase II	001-004 D(L)(I)	09/12/80	Upon Closure	Imposes restrictions on activities at the HNP landfill
EPA; GADNR	Federal Clean Air Act, as amended, (42 USC 7401 et seq., (40 CFR 50-99); GA Air Quality Act, Section 12-9-1, et seq. and the Rules, Chapter 391-3-1	Air Quality	4911-001-0001-V-01-0	02/04/99	02/04/04	The permit applies to the following units: Auxiliary Start-up Boiler Number 2 Two diesel engine fire pumps Five for emergency diesel generators One Security power diesel generator
NRC	10 CFR Part 50	NRC license, HNP Unit 1	DPR-57	08/06/74	08/06/14	None
NRC	10 CFR Part 50	NRC license, HNP Unit 2	NPF-5	06/13/78	06/13/18	None

CFR = Code of Federal Regulations
COE = U.S. Corps of Engineers
EPA = Environmental Protection Agency
GADNR = Georgia Department of Natural Resources
HNP = Edwin I. Hatch Nuclear Plant
NRC = U.S. Nuclear Regulatory Commission
USC = United States Code

Table 4-2. Environmental approvals and consultations for HNP license renewal.a

Agency	Authority	Requirement	Remarks
Federal			
NRC	Atomic Energy Act (42 USC 2011 et seq.) 10 CFR 54.23 10 CFR Part 51	License renewal	Environmental Report submitted in support of license renewal application.
USFWS and NMFS	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires Federal agency issuing a license to consult with FWS and NMFS. See Attachment C.
State			
GADNR	Clean Water Act Section 401 (33 USC 1341)	Certification	Requires applicant to provide certification from the State to Federal licensing agency.
GADNR Historic Preservation Division	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer. See Attachment D.

EPA = U.S. Environmental Protection Agency
FWS = U.S. Fish and Wildlife Service
GADNR = Georgia Department of Natural Resources
NMFS = National Marine Fisheries Service
NRC = U.S. Nuclear Regulatory Commission
a. No renewal-related requirements identified for local or other agencies.

5.0 GENERAL REFERENCES

1. Nuclear Operating Agreement between SNC and GPC, 1997.

2. HNP Environmental Report Construction Stage, 1971.

3. HNP Environmental Report Operating License Stage. 1975.

4. Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2; Georgia Power Company; Docket Nos. 50-321 and 50-366, Atomic Energy Commission, October 1972.

5. NUREG-0147, Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 2; Georgia Power Company; Docket Nos. 50-366, Atomic Energy Commission, March 1978.

6. NPDES Discharge Monitoring Reports January 1997 – September 1998.

7. Sumner, H. L., Southern Nuclear Operating Company, Inc., letter to U.S. Nuclear Regulatory Commission Document Control Desk, dated August 8, 1997, "Edwin I, Hatch Nuclear Plant Request for License Amendment Extended Power Uprate Operation."

8. Not used.

9. National Electrical Safety Code®, published by the Institute of Electrical and Electronics Engineers, 1997 Edition.

10. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," U.S. Nuclear Regulatory Commission, May 1996.

11. "Georgia Energy Data in Summary," Georgia Energy Facilities Authority, 1998.

12. Facts and Figures, Ga Power 1997.

13. Not used.

14. "Environmental Assessment for Cope Power Plant," South Carolina Electric and Gas Company, 1991.

15. "Electric Power Annual 1995, Volume II," DOE, Energy Information Administration, December 1996.

16. "Final Site Selection Study; 600 MW Coal-Fired Power Plant," Delmarva Power and Light Company, September 1992.

17. "Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources," EPA, AP-42, November 1996.

18. DOE/EIA-00191(97), "Cost and Quality of Fuels for Electric Utility Plants 1997 Tables," Energy Information Administration, DOE, May 1998.

19. HNP Monthly Operating Report, December 1997, January 1998.

20. EPA 904/9-94-002(a), "Final Environmental Impact Statement, Volume I: Tampa Electric Company - Polk Power Station," EPA, June 1994.

21. "The Beaver Combined Cycle Combustion Turbine Generating Plant," Portland General Electric, undated brochure.

22. DOE/EIA-0226(98/08), "Electric Power Monthly; August 1998 with Data for May 1998," Energy Information Administration, DOE, August 1998.

23. Local Climatological Data, NOAA 1996.

24. Not used.

25. Not used.

26. Not used.

27. Not used.

28. "Renewable Energy Annual; 1997" Energy Information Administration, DOE, February 1998.

29. Surface water use reports 1989-1997.

30. Groundwater use reports 1990-1997.

31. Not used.

32. Plant Edwin I. Hatch UFSAR Units 1 and 2.

33. "Edwin I. Hatch Nuclear Plant Environmental Field Survey Plan," Southern Nuclear Operating Company, August 1998.

34. Engineering Study on Induced Short Circuit Currents, Georgia Power Company, 1999 [SNC/GPC to provide citable reference for this evaluation of HNP 500kV lines].

35. Short Circuit Study on 230kV Lines From Plant Hatch, Georgia Power Company, 1999 [SNC/GPC to provide citable reference for this evaluation].

36. "TLWorkstation Code: Volume 7: ACDCLINE User's Manual Version 1.0," prepared for Electric Power Research Institute by the EPRI High Voltage Transmission Research Center, November 1991.

37. "Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment – Georgia," Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II), Revision 2, page 13, Bureau of Economic Analysis, U.S. Department of Commerce, Economics, and Statistics Administration, Washington, D.C., May 1992.

38. Joklik, W. K. and D. T. Smith (eds.), *Microbiology*, 15th edition, Appleton-Centry-Crofts, New York, New York, 1972.

39. Tyndall, R. L, K. S. Ironside, P. L. Metler, E. L. Tan, T. C. Hazen, and C. B. Fliermans, 1989. *"Effect of Thermal Additions on the Density and Distribution of a Thermophilic Amoebae and*

Pathogenic Naegleria Fowleri in a Newly Created Cooling Lake." Applied and Environmental Microbiology 55(3): 722-732.

40. 1990 U.S. Census Data.

41. Sellars, J., Appling County Board of Education, personal communication with J. B. Hovey, Tetra Tech, Inc, Aiken, South Carolina, "Student/Teacher data for Appling County, Georgia schools," October 30, 1998.

42. Alman, B., Toombs Central Elementary School, personal communication with J. B. Hovey, Tetra Tech, Inc, Aiken, South Carolina, "Student/Teacher data," November 2, 1998.

43. Burton, K., Toombs Middle School, personal communication with J. B. Hovey, Tetra Tech, Inc, Aiken, South Carolina, "Student/Teacher data," November 2, 1998.

44. Denmark, B., Lyons Elementary School, personal communication with J. B. Hovey, Tetra Tech, Inc, Aiken, South Carolina, "Student/Teacher data," October 30, 1998.

45. Culpepper, E., Toombs County High School, personal communication with J. B. Hovey, Tetra Tech, Inc, Aiken, South Carolina, "Student/Teacher data," October 30, 1998.

46. "Unity of Vision: Appling County, Baxley, Graham, and Surrency 2011, A Joint Comprehensive Plan for Appling County, the City of Baxley, the City of Graham, and the Town of Surrency, Georgia in accordance with the Georgia Planning Act of 1989", Appling County Joint Planning Board, Altamaha Georgia Southern Regional Development Center, January 1997.

47. State of Georgia Traffic count data.

48. Memorandum from J. C. Hoyle (NRC) to L. J. Callan (NRC), dated January 13, 1998, "Staff Requirements – SECY-97-279 – Generic and Cumulative Environmental Impacts of Transportation of High-Level Waste (HLW) in the Vicinity of an HLW Repository (SRM M970612)."

49. "EPA's Regional Emissions Plan Leaves Utilities Breathless," *Engineering New Record*, October 5, 1998.

50. NUREG/CR-6525, SECPOP90: Sector Population, Land Fraction, and Economic Estimation Program, Office of Nuclear Regulatory Research, U.S. Nuclear Commission, Washington, D.C., September 1997.

51. Ms. D. Carter, Appling County Tax Commissioner's Office personal communication with J. B. Hovey, Tetra Tech, Inc., "Tax payment amount for the Edwin I. Hatch Plant," November 1998.

52. "Together and Forward: Toombs County, Lyons, Santa Claus, and Vidalia 2012, A Joint Comprehensive Plan for Toombs County, the City of Lyon, the City of Santa Claus, and the City of Vidalia, Georgia in accordance with the Georgia Planning Act of 1989," Toombs County Comprehensive Plan Steering Committee, Altamaha Georgia Southern Regional Development Center, April 1992.

53. Fetter, C. W., *Applied Hydrogeology*, Second Edition, Macmillan Publishing Company, New York, New York, 1988.

54. "Significant Species Survey of Plant Hatch Appling County, Georgia," The Nature Conservancy of Georgia, 1995.

55. "Wildlife Habitat Council 1996 Recertification Application for Edwin I. Hatch Nuclear Plant," submitted by The Southern Company.

56. "Freshwater Mussel Survey, Altamaha River, Appling and Toombs Counties, Georgia," Law Engineering and Environmental Services, December 2, 1998.

57. Personal communication between J. A. Cudworth, Tetra Tech, Inc., and A. L. Clapp, Clapp Associates, February 26, 1999.

58. Wiltz, J. W., "Plant Edwin I. Hatch 316(b) Demonstration on the Altamaha River in Appling County Georgia," March 1981.

59. McMahon, R. R., "Mollusca: Bivalvia" in J. H. Thorp and A. P. Covich (editors), *Ecology and Classification of North American Freshwater Invertebrates*, Academic Press, Inc., San Diego, California, 1991.

60. Pennak, R. W., *Fresh-water Invertebrates of the United States*, John Wiley & Sons, New York, 1978.

61. DG-4005, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," U.S. Nuclear Regulatory Commission, Draft Regulatory Guide, July 1998.

62. NUREG-0586, "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," U.S. Nuclear Regulatory Commission, August 1998.

63. NUREG-1437, Addendum 1 "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Main Report, Section 6.3 - Transportation, Table 9.1 Summary of Findings on NEPA issues for License Renewal of nuclear power plants," Draft Report for Comment, U.S. Nuclear Regulatory Commission, February 1999.

64. DOE/FEIS-0201, "Final Environmental Impact Statement Coyote Springs Cogeneration Project, Morrow County, Oregon, U.S. Department of Energy, July 1994.

65. "Threatened and Endangered Species Surveys: E.I. Hatch Nuclear Plant and Associated Transmission Line Corridors (1998-1999)," Southern Nuclear Operating Company, September 1999.

66. Georgia Natural Heritage Program (GNHP), 1997. Georgia Power Company location of rare species and natural communities within ¼ mile of Georgia Power transmission lines. Georgia Department of Natural Resources, Social Circle, Georgia.

67. Georgia Natural Heritage Program (GNHP), 1999b. Georgia element occurrence record database. Georgia Department of Natural Resources, Social Circle, Georgia, March 31.

68. Southern Company, "Wildlife Habitat Council 1999 Recertification Application for Edwin I. Hatch Nuclear Plant," July 1999.

69. Feimster, B., Georgia Power Company (HNP), personal communication with J. Bouknight, Tetra Tech, Inc., Aiken, South Carolina, October 12, 1999.

70. Memorandum from T.C. Moorer (Southern Nuclear Operating Company-Environmental Services) to C. R. Pierce (Southern Nuclear Operating Company-License Renewal Services) dated September 27, 1999, "Review of New and Significant Information Relative to License Renewal."

71. Council on Environmental Quality, "Environmental Justice: Guidance Under the National Environmental Policy Act," December 10, 1997.

72. Office of Nuclear Reactor Regulation (NRR), NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues," September 21, 1999.

73. "Environmental Permits Manual," Southern Company, undated.

ATTACHMENT A. NRC NATIONAL ENVIRONMENTAL POLICY ACT ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

Southern Nuclear Operating Company has prepared this Environmental Report – Operating License Renewal Stage for the Edwin I. Hatch Nuclear Plant (HNP) in accordance with the requirements of 10 CFR 51.53. Included in the regulation is a list of environmental issues that the U.S. Nuclear Regulatory Commission (NRC) developed from the analysis presented in NRC's Generic Environmental Impact Statement (Reference 1), which examines possible environmental impacts that could occur as a result of renewing licenses of individual nuclear power plants. These 92 issues are listed in Table B-1 of Appendix B to Subpart A of Part 51 and are provided in Table A-1 of this document. For expediency, numbers have been assigned to each issue as it appears in Table B-1 and are referenced throughout this Environmental Report. Table A-1 also provides a cross-reference for each of NRC's environmental issues to the respective environmental report section where that issue is discussed.

Reference

1. NUREG-1437, Volume 1, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," December 1996.

Table A-1. HNP environmental report discussion of license renewal national environmental policy act issues (page 1 of 3).

	Issue[a]	Category	Section of this Environmental Report
1.	Impacts of refurbishment on surface water quality	1	3.1.1
2.	Impacts of refurbishment on surface water use	1	3.1.1
3.	Altered current patterns at intake and discharge structures	1	3.1.1
4.	Altered salinity gradients	1	3.1.1
5.	Altered thermal stratification of lakes	1	NA[b]
6.	Temperature effects on sediment transport capacity	1	3.1.1
7.	Scouring caused by discharged cooling water	1	3.1.1
8.	Eutrophication	1	3.1.1
9.	Discharge of chlorine or other biocides	1	3.1.1
10.	Discharge of sanitary wastes and minor chemical spills	1	3.1.1
11.	Discharge of other metals in waste water	1	3.1.1
12.	Water use conflicts (plants with once-through cooling systems)	1	NA[c]
13.	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	3.1.2
14.	Refurbishment impacts to aquatic resources	1	3.1.1
15.	Accumulation of contaminants in sediments or biota	1	3.1.1
16.	Entrainment of phytoplankton and zooplankton	1	3.1.1
17.	Cold shock	1	3.1.1
18.	Thermal plume barrier to migrating fish	1	3.1.1
19.	Distribution of aquatic organisms	1	3.1.1
20.	Premature emergence of aquatic insects	1	3.1.1
21.	Gas supersaturation (gas bubble disease)	1	3.1.1
22.	Low dissolved oxygen in the discharge	1	3.1.1
23.	Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	3.1.1
24.	Stimulation of nuisance organisms (e.g., shipworms)	1	3.1.1
25.	Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA[c]
26.	Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA[c]
27.	Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA[c]
28.	Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	3.1.1
29.	Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	3.1.1
30.	Heat shock for plants with cooling-tower-based heat dissipation systems	1	3.1.1
31.	Impacts of refurbishment on ground-water use and quality	1	3.1.1
32.	Ground-water use conflicts (potable and service water; plants that use < 100 gpm)	1	NA[d]
33.	Ground-water use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	2	3.1.3

Table A-1. HNP environmental report discussion of license renewal national environmental policy act issues (page 2 of 3).

	Issue[a]	Category	Section of this Environmental Report
34.	Ground-water use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	3.1.3
35.	Ground-water use conflicts (Ranney wells)	2	NA[e]
36.	Ground-water quality degradation (Ranney wells)	1	NA[e]
37.	Ground-water quality degradation (saltwater intrusion)	1	3.1.1
38.	Ground-water quality degradation (cooling ponds in salt marshes)	1	NA[c]
39.	Ground-water quality degradation (cooling ponds at inland sites)	2	NA[c]
40.	Refurbishment impacts to terrestrial resources	2	3.1.4
41.	Cooling tower impacts on crops and ornamental vegetation	1	3.1.1
42.	Cooling tower impacts on native plants	1	3.1.1
43.	Bird collisions with cooling towers	1	NA[f]
44.	Cooling pond impacts on terrestrial resources	1	NA[c]
45.	Power line right-of-way management (cutting and herbicide application)	1	3.1.1
46.	Bird collisions with power lines	1	3.1.1
47.	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	3.1.1
48.	Floodplains and wetlands on power line right of way	1	3.1.1
49.	Threatened or endangered species	2	3.1.5
50.	Air quality during refurbishment (non-attainment and maintenance areas)	2	3.1.6
51.	Air quality effects of transmission lines	1	3.1.1
52.	Onsite land use	1	3.1.1
53.	Power line right of way	1	3.1.1
54.	Radiation exposures to the public during refurbishment	1	3.1.1
55.	Occupational radiation exposures during refurbishment	1	3.1.1
56.	Microbiological organisms (occupational health)	1	3.1.1
57.	Microbiological organisms (public health)(plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	3.1.7
58.	Noise	1	3.1.1
59.	Electromagnetic fields, acute effects (electric shock)	2	3.1.8
60.	Electromagnetic fields, chronic effects	NA[g]	NA[g]
61.	Radiation exposures to public (license renewal term)	1	3.1.1
62.	Occupational radiation exposures (license renewal term)	1	3.1.1
63.	Housing impacts	2	3.1.9
64.	Public services: public safety, social services, and tourism and recreation	1	3.1.1
65.	Public services: public utilities	2	3.1.10
66.	Public services, education (refurbishment)	2	3.1.11
67.	Public services, education (license renewal term)	1	3.1.1
68.	Offsite land use (refurbishment)	2	3.1.12

Table A-1. HNP environmental report discussion of license renewal national environmental policy act issues (page 3 of 3).

	Issue[a]	Category	Section of this Environmental Report
69.	Offsite land use (license renewal term)	2	3.1.13
70.	Public services, transportation	2	3.1.14
71.	Historic and archaeological resources	2	3.1.15
72.	Aesthetic impacts (refurbishment)	1	3.1.1
73.	Aesthetic impacts (license renewal term)	1	3.1.1
74.	Aesthetic impacts of transmission lines (license renewal term)	1	3.1.1
75.	Design basis accidents	1	3.1.1
76.	Severe accidents	2	3.1.16
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)	1	3.1.1
78.	Offsite radiological impacts (collective effects)	1	3.1.1
79.	Offsite radiological impacts (spent fuel and high level waste disposal)	1	3.1.1
80.	Nonradiological impacts of the uranium fuel cycle	1	3.1.1
81.	Low-level waste storage and disposal	1	3.1.1
82.	Mixed waste storage and disposal	1	3.1.1
83.	On-site spent fuel	1	3.1.1
84.	Nonradiological waste	1	3.1.1
85.	Transportation	1	3.1.1
86.	Radiation doses (decommissioning)	1	3.1.1
87.	Waste management (decommissioning)	1	3.1.1
88.	Air quality (decommissioning)	1	3.1.1
89.	Water quality (decommissioning)	1	3.1.1
90.	Ecological resources (decommissioning)	1	3.1.1
91.	Socioeconomic impacts (decommissioning)	1	3.1.1
92.	Environmental justice	NA[g]	3.1.18

a. Source: 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue numbers added to facilitate discussion.)
b. Not applicable because HNP is not located on a lake.
c. Not applicable because HNP does not use a cooling pond or once-through heat dissipation system.
d. Not applicable because HNP uses > 100 gpm of groundwater.
e. Not applicable because HNP does not use Ranney wells.
f. Not applicable because HNP does not use natural draft cooling towers (NUREG-1437, Section 4.3.5.2).
g. Not applicable because the categorization and impact finding definitions do not apply to this issue (10 CFR 51, Subpart A, Appendix B, Table B-1, footnote 4).

ATTACHMENT B. SURFACE WATER WITHDRAWAL IMPACT ASSESSMENT

B.1 Surface Water Impact Calculations

The U.S. Geological Survey (USGS) measures streamflow characteristics at locations, called gauging stations, throughout the U.S. The USGS has prepared tables, called rating tables, that show the relationship between the height of water at a gauging station and the volume of water, called discharge, passing that station. For example, Rating Table 13 for USGS Gauging Station 02225000, located in Georgia on the Altamaha River at the U. S. Highway 1 bridge indicates that if the gauge height reading is 8.7 feet, the USGS has calculated that the river discharge at that time is 11,520 cubic feet per second. Conversely, if the river discharge were 9,619 cubic feet per second, the expected gauge height reading would be 7.7 feet. A copy of Rating Table 13 is attached as Table B-1.

The reader will note that the right-hand column of Rating Table 13 shows the difference in river discharge, Q, per foot of gauge height. If the river sides were vertical, the difference would remain effectively the same regardless of gauge height; each additional 1,000 cubic feet per second, for example, would raise the river height the same amount. Because rivers in cross section are generally shaped like a broad letter "V," however, the higher the water level, the more room there is to contain water. This is why Rating Table 13 indicates that an increase in gauge height from 1 foot to 2 feet adds only 732 cubic feet per second of discharge whereas an increase from 21 feet to 22 feet adds 17,500 cubic feet per second.

The USGS also publishes annual summaries of streamflow data for each gauging station. Attached, as Table B-2, is the water year[1] 1997 discharge data for Altamaha River Gauging Station 02225000. For example, the table indicates that on January 20, 1997, the river discharge was 22,500 cubic feet per second. Referring to Rating Table 13 (Table B-1), this value corresponds to the gauge height of 13 feet, the approximate gauge reading on that day.

In addition to annual discharge data, Table B-2 presents statistical analyses of annual and multi-year data. The table indicates that, based on 49 years of data (1949 – 1997), 11,580 cubic feet per second is the river's annual mean discharge, that March is the month that has the highest mean discharge (24,570 cubic feet per second) and maximum discharge (47,260 cubic feet per second), and that September is the month that has the lowest mean discharge (4,907 cubic feet per second) and minimum discharge (1,864 cubic feet per second). The annual discharge table for fiscal year 1990, attached as Table B-3, also indicates that the historical lowest daily mean was 1,620 cubic feet on July 21, 1986.

The equations use data presented in attached ratings and annual discharge tables in calculating information presented in Section 3.1.2.1.

EQUATION B.1 – ANNUAL FLOW RATE

Calculate the Altamaha River annual flow rate in cubic feet per year by converting average mean discharge of 11,580 cubic feet per second from Table B-2:

> 11,580 cubic feet per second × 3,600 seconds per hour × 24 hours per day × 365 days per year = 365,186,880,000 or 3.65 × 1011 cubic feet per year

1. A water year runs from October 1 through September 30.

EQUATION B.2 – IMPACT ON AVERAGE FLOW

Calculate the percent that HNP cooling water consumptive use by evaporation, 32.6 million gallons per day (Section 2.1.4), reduces Altamaha River the annual mean discharge of 11,580 cubic feet per second (cfs) (Table B-1). First, convert consumptive loss units to same as discharge units:

$$\frac{32{,}600{,}000 \text{ gallons per day} \times 0.1336719 \text{ cubic feet per gallon}}{3600 \text{ seconds per hour} \times 24 \text{ hours per day}} = 50.44 \text{ cubic feet per second}$$

Second, determine percentage represented by consumptive loss:

$$\frac{50.44 \text{ cubic feet per second}}{11{,}580 \text{ cubic feet per second}} \text{x}100 = 0.44 \text{ percent}$$

EQUATION B.3 – IMPACT ON MINIMUM FLOW

Calculate the percent that HNP cooling water consumptive use by evaporation, 50.44 cubic feet per second (Equation B-2), would have reduced the Altamaha River historic lowest daily mean discharge of 1,620 cubic feet per second (Table B-3):

$$\frac{50.44 \text{ cubic feet per second}}{1{,}620 \text{ cubic feet per second}} \text{x}100 = 3.1 \text{percent}$$

EQUATION B.4 – IMPACT ON AVERAGE ELEVATION

Calculate the amount that HNP cooling water consumptive use by evaporation, 50.44 cubic feet per second (Equation B.2), reduces the Altamaha River elevation at the time of the annual mean discharge of 11,580 cubic feet per second.

Table B-1 is the USGS rating table for the referenced gauging station. It provides flow rates for gage height increments of 0.1 feet. For all practical purposes, there is a straight line relationship between gage height and flow rate between these small increments of gage height.

The average flow rate of 11,580 cfs is between the following points on the rating table.

Flow rate (cfs)	Gage height (feet)
11,520	8.7
11,720	8.8

A straight line between these points is:

$$\text{gage height (ft)} = 8.7 + \frac{8.8 - 8.7}{11{,}720 - 11{,}520} \times (\text{flow rate} - 11{,}520)$$

therefore, 11,580 cfs occurs at a gage height of

$$8.7 + \frac{0.1}{200}(11{,}580 - 11{,}520) = 8.73 \text{ ft}$$

subtraction of the consumptive withdrawal reduces the flow rate to

$$11{,}580 - 50.44 = 11{,}529.6 \text{ cfs}$$

This is also between the two reference points, therefore gage height would be

$$8.7 + \frac{.1}{200} \times (11{,}529.6 - 11{,}520) = 8.70 \text{ ft}$$

The difference in gage height (0.03 ft) is negligible.

EQUATION B.5 – IMPACT ON MINIMUM ELEVATION

Calculate the amount that HNP cooling water consumptive use by evaporation, 50.44 cubic feet per second (Equation B.2) would have reduced the Altamaha River historic lowest daily mean discharge of 1,620 cubic feet per second (Table B-3):

The lowest flow rate of record (1,620 cfs) is between the following points on the rating table:

Flow rate (cfs)	Gage height (feet)
1,553	1.1
1,621	1.2

A straight line between these points is:

$$\text{gage height (ft)} = \quad 1.1 + \frac{1.2 - 1.1}{1{,}621 - 1{,}553}(\text{flow rate} - 1{,}553)$$

therefore, 1,620 cfs occurs at a gage height of:

$$1.1 + \frac{0.1}{68} \text{x} (1{,}620 - 1{,}553) = 1.20 \text{ ft}$$

subtraction of the consumptive withdrawal reduces the flow rate to

1,620 – 50.44 = 1,569.6

This is also between the two reference points, therefore gage height would be

$$1.1 + \frac{0.1}{68} \text{x} (1{,}569.6 - 1{,}553) = 1.12 \text{ ft}$$

The difference in gage height (0.08 ft) is negligible.

Table B-1. USGS Expanded Rating Table, Altamaha River Station 02225000, Rating No. 13.0.

UNITED STATES DEPARTMENT OF INTERIOR - GEOLOGICAL SURVEY - WATER RESOURCES DIVISION PAGE 1
EXPANDED RATING TABLE TYPE: LOG
02225000 DATE PROCESSED: 12-22-1998 ● 11:35 BY wrstokes
ALTAMAHA RIVER NEAR BAXLEY, GA. DD: 3 TYPE: 001 RATING NO: 13.0
OFFSET: -4.0 START DATE/TIME: 10-01-1997 (0001)

BASED ON ________ DISCHARGE MEASUREMENTS, NOS ________, AND ________, AND IS ________ WELL DEFINED BETWEEN ________ AND ________ CFS
COMP BY ______ DATE ________ CHK. BY ______ DATE ________
SAME AS RATING NO 12 BELOW 20 FEET.

GAGE HEIGHT (FEET)	DISCHARGE IN CUBIC FEET PER SECOND .0	.1	.2	.3	.4	(EXPANDED PRECISION) .5	.6	.7	.8	.9	DIFF IN Q PER FOOT
.0						1180*	1238	1298	1360	1423	614.0
1.0	1487	1553	1621	1690	1761	1833	1907	1983	2060	2139	732.0
2.0	2219	2301	2385	2470	2557	2646	2736	2828	2922	3017	895.0
3.0	3114	3212	3312	3414	3518	3623	3730	3838	3949	4061	1061
4.0	4175	4290	4407	4526	4647	4769	4893	5019	5146	5276	1232
5.0	5407	5540	5674	5810	5948	6088	6230	6373	6519	6665	1407
6.0	6814	6965	7117	7271	7427	7585	7744	7906	8069	8234	1587
7.0	8401	8569	8740	8912	9086	9262	9440	9619	9801	9984	1769
8.0	10170	10360	10550	10740	10930	11120	11320	11520	11720	11920	1950
9.0	12120	12330	12540	12750	12960	13170	13390	13600	13820	14040	2150
10.0	14270	14490	14720	14950	15180	15410	15640	15880	16120	16360	2330
11.0	16600*	16870	17140	17410	17690	17970	18250	18530	18820	19110	2800
12.0	19400*	19700	20000	20300	20610	20920	21230	21540	21860	22180	3100
13.0	22500*	22880	23270	23660	24050	24450	24850	25260	25670	26080	4000
14.0	26500*	26990	27490	27990	28500	29020	29540	30070	30610	31150	5200
15.0	31700*	32290	32900	33500	34120	34750	35380	36020	36670	37330	6300
16.0	38000*	38680	39370	40070	40780	41500*	42280	43070	43870	44680	7500
17.0	45500*	46370	47260	48160	49070	50000*	50910	51840	52780	53730	9200
18.0	54700*	55650	56600	57570	58560	59550	60560	61570	62610	63650	10010
19.0	64710	65780	66860	67960	69060	70190	71320	72470	73630	74810	11290
20.0	76000*	77250	78510	79790	81090	82400	83720	85060	86420	87790	13180
21.0	89180	90590	92010	93450	94910	96380	97870	99380	100900	102400	14820
22.0	104000*	105700	107300	109000	110700	112500	114200	116000	117800	119600	17500
23.0	121500	123300	125200	127100	129100	131000	133000	135000	137000	139000	19600
24.0	141100	143200	145300	147400	149600	151700	153900	156200	158400	160700	21900*
25.0	163000*										

Table B-2. USGS Discharge Table for the Altamaha River Water Year October 1996 to September 1997 (Station 02225000).

UNITED STATES DEPARTMENT OF THE INTERIOR - GEOLOGICAL SURVEY - GEORGIA INSTALLATION 12/22/1998

STATION NUMBER 02225000 ALTAMAHA RIVER NEAR BAXLEY, GA. STREAM SOURCE AGENCY USGS
LATITUDE 315620 LONGITUDE 0822113 DRAINAGE AREA 11600.00 DATUM 61.51 STATE 13 COUNTY 001

DISCHARGE, CUBIC FEET PER SECOND, WATER YEAR OCTOBER 1996 TO SEPTEMBER 1997
DAILY MEAN VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	3350	2790	3730	6300	17700	49900	7920	11600	6220	5320	8750	2430
2	3340	2730	4070	6160	17400	47500	7960	12800	6710	5610	6790	2380
3	3980	2680	4670	6500	16300	43800	7880	14000	6920	6360	6530	2330
4	4780	2700	5960	6660	15400	39400	7540	15200	7090	6060	6990	2270
5	5190	2800	7800	6790	14600	34800	7190	16100	6990	5680	7220	2220
6	5510	2880	9170	6880	13800	31200	6960	17000	6790	5680	6960	2150
7	5320	2890	10200	6930	13200	28800	6630	17800	6580	5660	6600	2080
8	5520	2890	10200	7230	12600	27900	6200	18600	6490	5040	6280	2040
9	6420	3010	8690	8470	12200	29200	5890	19200	6430	4640	5720	1990
10	7070	3380	7530	10400	11600	32900	5820	19700	6310	4200	5230	1950
11	7300	3860	7100	12300	11300	36900	6190	19500	6130	3880	4900	1920
12	6960	4680	7150	13600	11400	40100	6260	17800	5860	3810	4480	1860
13	6690	4920	7040	14800	11300	41300	6100	14800	5380	3720	3920	1840
14	6340	5000	6550	15900	12400	39400	5980	12000	4840	3600	3560	1820
15	5720	5110	6210	17100	17100	35500	5720	10200	4430	3510	3360	1820
16	4960	5250	6200	18500	22900	31900	5390	9300	4250	3480	3230	1840
17	4350	5350	6120	19900	26500	27700	5110	8880	4390	3400	3190	1850
18	3980	4930	6060	21100	28700	23800	5050	8180	5000	3300	3280	1850
19	3660	4490	6630	22000	29600	20700	5490	7000	6560	3210	3250	1840
20	3450	4230	7880	22500	30000	18200	5820	6070	7600	3240	3200	1820
21	3420	3810	9150	22300	30700	16000	5710	5230	8310	3370	3260	1810
22	3350	3510	9460	20800	33100	14500	5370	4700	9070	3790	3470	1830
23	3220	3330	9030	19200	38600	13600	5180	4380	9820	4070	3450	1820
24	3090	3380	8120	18400	44700	12900	4820	4280	10300	4360	3230	1820
25	2990	3670	7090	17600	48600	12100	4530	4530	9330	4250	3020	1800
26	2900	3800	6310	16500	50600	11100	4470	4670	7690	3990	2860	1820
27	2820	3820	6070	16000	50900	10200	4850	4500	6640	5310	2710	1900
28	2800	3800	5870	15500	50800	9220	6720	4340	6310	6970	2630	2310
29	2780	3680	5530	15000	---	8520	9140	4490	6140	8220	2590	4660
30	2800	3640	5830	15200	---	8110	10700	4840	5590	9380	2530	6770
31	2820	---	6630	16400	---	8030	---	5530	---	10100	2490	---
TOTAL	136880	113010	218050	442920	694000	805180	188590	327220	200170	153210	135680	66840
MEAN	4415	3767	7034	14290	24790	25970	6286	10560	6672	4942	4377	2228
MAX	7300	5350	10200	22500	50900	49900	10700	19700	10300	10100	8750	6770
MIN	2780	2680	3730	6160	11300	8030	4470	4280	4250	3210	2490	1800
CFSM	.38	.32	.61	1.23	2.14	2.24	.54	.91	.58	.43	.38	.19
IN.	.44	.36	.70	1.42	2.23	2.58	.60	1.05	.64	.49	.44	.21

STATISTICS OF MONTHLY MEAN DATA FOR WATER YEARS 1949 - 1997, BY WATER YEAR (WY)

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
MEAN	5577	5729	10060	16030	22410	24570	19080	9903	7057	6506	6351	4907
MAX	24560	14480	29870	36550	41600	47260	41730	20630	19380	32470	19600	13860
(WY)	1995	1996	1993	1993	1973	1975	1975	1975	1973	1994	1994	1949
MIN	1864	2115	2763	3395	4803	9112	5635	2576	2302	1796	1902	2228
(WY)	1982	1982	1988	1981	1989	1985	1986	1986	1988	1988	1988	1997

SUMMARY STATISTICS	FOR 1996 CALENDAR YEAR		FOR 1997 WATER YEAR		WATER YEARS 1949 - 1997	
ANNUAL TOTAL	4023250		3481750			
ANNUAL MEAN	10990		9539		11580	
HIGHEST ANNUAL MEAN					17720	1975
LOWEST ANNUAL MEAN					5210	1988
HIGHEST DAILY MEAN	57800	Feb 12	50900	Feb 27	97900	Jul 16 1994
LOWEST DAILY MEAN	2650	Sep 22	1800	Sep 25		
ANNUAL SEVEN-DAY MINIMUM	2760	Oct 29	1820	Sep 20	1660	Jul 17 1986
INSTANTANEOUS PEAK FLOW			51300	Feb 27	98800	Jul 16 1994
INSTANTANEOUS PEAK STAGE			17.64	Feb 27	22.70	Mar 12 1971
ANNUAL RUNOFF (CFSM)	.95		.82		1.00	
ANNUAL RUNOFF (INCHES)	12.90		11.17		13.56	
10 PERCENT EXCEEDS	27500		20700		25500	
50 PERCENT EXCEEDS	6410		6160		7190	
90 PERCENT EXCEEDS	3140		2760		2720	

STATISTICS COMPUTED BY: rogermc DATE: 04/21/1998 AT: 07:48:32

Table B-3. USGS Water Discharge Record Water Year October 1990 to September 1991, Altamaha River Station 02225000.

ALTAMAHA RIVER BASIN

02225000 ALTAMAHA RIVER NEAR BAXLEY, GA.

LOCATION.--Lat 31°56'20", long 82°21'13", Appling-Toombs County line, Hydrologic Unit 03070106, on right bank 400 ft downstream from bridge on U.S. Highway 1, 2.2 mi upstream from Bay Creek, 6 mi downstream from Bullards Creek, and 12 mi north of Baxley.
DRAINAGE AREA.--11,600 mi^2, approximately.

WATER-DISCHARGE RECORDS

PERIOD OF RECORD.--August 1949 to June 1951, October 1970 to current year.
GAGE.--Water-stage recorder. Datum of gage is 61.51 ft above National Geodetic Vertical Datum of 1929. Aug. 13, 1949, to June 30, 1 nonrecording gage at site 400 ft upstream at same datum.
REMARKS.--No estimated daily discharges. Records good.
AVERAGE DISCHARGE.--22 years (water years 1950, 1971-91), 11,190 ft^3/s, 13.10 in/yr.
EXTREMES FOR PERIOD OF RECORD.--Maximum discharge, 97,600 ft^3/s, Mar. 12, 1971, gage height, 22.7 ft; minimum daily discharge, 1,620 ft^3/s, July 21, 1988.
EXTREMES OUTSIDE PERIOD OF RECORD.--Flood of Dec. 10, 1948, reached a stage of 25.1 ft, from floodmark, discharge, 130,000 ft^3/s. Flood of January 1925 reached a stage of 30.0 ft, from information furnished by Georgia Department of Transportation.
EXTREMES FOR CURRENT YEAR.--Peak discharges greater than base discharge of 25,000 ft^3/s and maximum (*):

Date	Time	Discharge (ft^3/s)	Gage height (ft)	Date	Discharge Time	Gage height (ft^3/s)	(ft)
Feb. 7	2100	50,500	17.75	Apr. 10	2000	28,100	14.78
Mar. 10	1100	*62,500	*19.04				

Minimum daily discharge, 2,330 ft^3/s, Oct. 9.

DISCHARGE, CUBIC FEET PER SECOND, WATER YEAR OCTOBER 1990 TO SEPTEMBER 1991
DAILY MEAN VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	2450	6030	3590	5230	31000	14400	14900	16200	10600	9300	13300	17100
2	2420	5560	4070	5430	33900	16000	16200	16200	10800	9600	17900	17200
3	2380	4850	4250	5800	37000	21800	17300	18100	10900	9830	20600	16000
4	2350	4650	3890	5960	42000	30800	18500	16100	10700	9840	21100	12800
5	2350	5180	3690	6050	47400	41900	20400	18400	11200	9750	19800	10000
6	2380	5190	3710	6200	49600	51100	23100	17100	11900	9640	17700	8860
7	2420	4470	4430	6470	50100	57300	25100	17900	12700	9660	15500	8140
8	2370	4260	4980	6650	50200	60200	26600	18600	12700	10300	13300	7880
9	2330	5510	5260	6330	49400	61300	27600	19200	11400	10800	11100	7890
10	2480	6870	5520	5940	47800	62000	28000	19000	10200	10700	9070	7320
11	2700	8190	5190	6110	45400	61400	27900	18800	9100	10500	7940	6660
12	3140	9110	4700	8260	42200	59200	27500	19300	7900	10500	8440	5910
13	4050	9590	4590	10600	37300	55900	26600	19600	6540	9740	10200	5190
14	6660	9340	4710	12300	30800	51800	25300	19700	5700	9200	9940	4670
15	8680	8450	4880	13700	25900	46900	23700	20100	5480	9360	10000	4340
16	9620	7300	4880	14500	22400	40700	22400	20700	5470	10200	11000	4180
17	6940	6280	4800	14700	20100	33400	21700	21700	5630	11900	12000	3930
18	6820	5720	4360	15100	18100	28300	21200	22900	5980	13300	12700	3640
19	5380	5450	4220	15600	16100	25600	19800	24000	6330	14700	13300	3490
20	4550	5210	4570	17300	14500	23600	18300	24300	6400	15900	13500	3630
21	4110	4560	5310	19400	13100	21800	18300	22700	6490	16400	12600	3740
22	4170	4130	5550	20800	12300	19900	15500	20600	7280	16700	12000	3650
23	4220	3910	5470	21600	11800	18600	15400	19200	7720	16800	11900	3530
24	4160	3800	5580	22100	11400	17000	15600	18000	7960	16300	11200	3450
25	4630	3870	5740	23100	11500	15400	15800	16700	8430	15000	9980	3360
26	6280	3950	5980	24200	12100	14200	16100	15300	8870	14000	10600	3260
27	8120	3880	6350	24700	12900	12900	16400	13900	8600	13400	12500	3220
28	9150	3730	6060	25300	13700	12000	16300	12800	8380	13000	13400	3320
29	9110	3580	5640	25800	—	11900	16600	11900	8500	12500	13800	3210
30	8240	3490	5380	27500	—	12600	16400	11200	8890	12000	15000	3110
31	6650	—	5270	29300	—	13400	—	10900	—	12000	16300	---
TOTAL	153510	166130	152360	451930	810000	1013300	612400	557300	258750	373020	407770	192480
MEAN	4952	5538	4915	14580	28930	32690	20410	17980	8625	12030	13150	6418
MAX	9620	9590	6350	29300	50200	62000	28000	24300	12700	16800	21100	17200
MIN	2330	3490	3590	5230	11400	11900	14900	10900	5470	9200	7940	3110
CFSM	.43	.48	.42	1.26	2.49	2.82	1.76	1.55	.74	1.04	1.13	.55
IN.	.49	.53	.49	1.45	2.60	3.25	1.96	1.79	.83	1.20	1.31	.62

CAL YR 1990	TOTAL 3905730	MEAN 10700	MAX 65000	MIN 1840	CFSM .92	IN. 12.53
WTR YR 1991	TOTAL 5140970	MEAN 14110	MAX 62000	MIN 2330	CFSM 1.22	IN. 16.51

ATTACHMENT C. SPECIAL-STATUS SPECIES CONSULTATIONS

Attachment C presents letters Southern Nuclear Operating Company submitted to the Georgia Department of Natural Resources requesting information on state-listed species in the project area and to the U.S. Fish and Wildlife Service and National Marine Fisheries Service requesting information on Federally-listed that might be present and that could be affected by the proposed action.

5131 Maner Road
Smyrna, Georgia 30080

Tel 404 799 2100
Fax 404 799 2111

GEORGIA POWER
A SOUTHERN COMPANY

December 16, 1997

Georgia Department of Natural Resources
Wildlife Resources Division
Natural Heritage Program
2117 U. S. Hwy.278
Social Circle, Georgia 30279

Attention: Mr. Greg Krakow, Data Manager

Re: Request for
Threatened & Endangered
Species Information

Dear Mr. Krakow:

Southern Nuclear is in the process of preparing an application for a license extension for Plant Hatch near Baxley, Georgia. We anticipate the need for an endangered species survey for the site as a part of this application. We are requesting that you conduct a search of your data base for known locations of Threatened & and Endangered Species within and around the immediate project site. I have a copy of the most resent lists for Threatened and Endangered Species for Appling and Toombs counties from the U.S. Fish and Wildlife Service. The approximate location of the Plant site is indicated on the attached photocopy of the Baxley NE, Ga. 7.5 Minute Topographic Quadrangle.

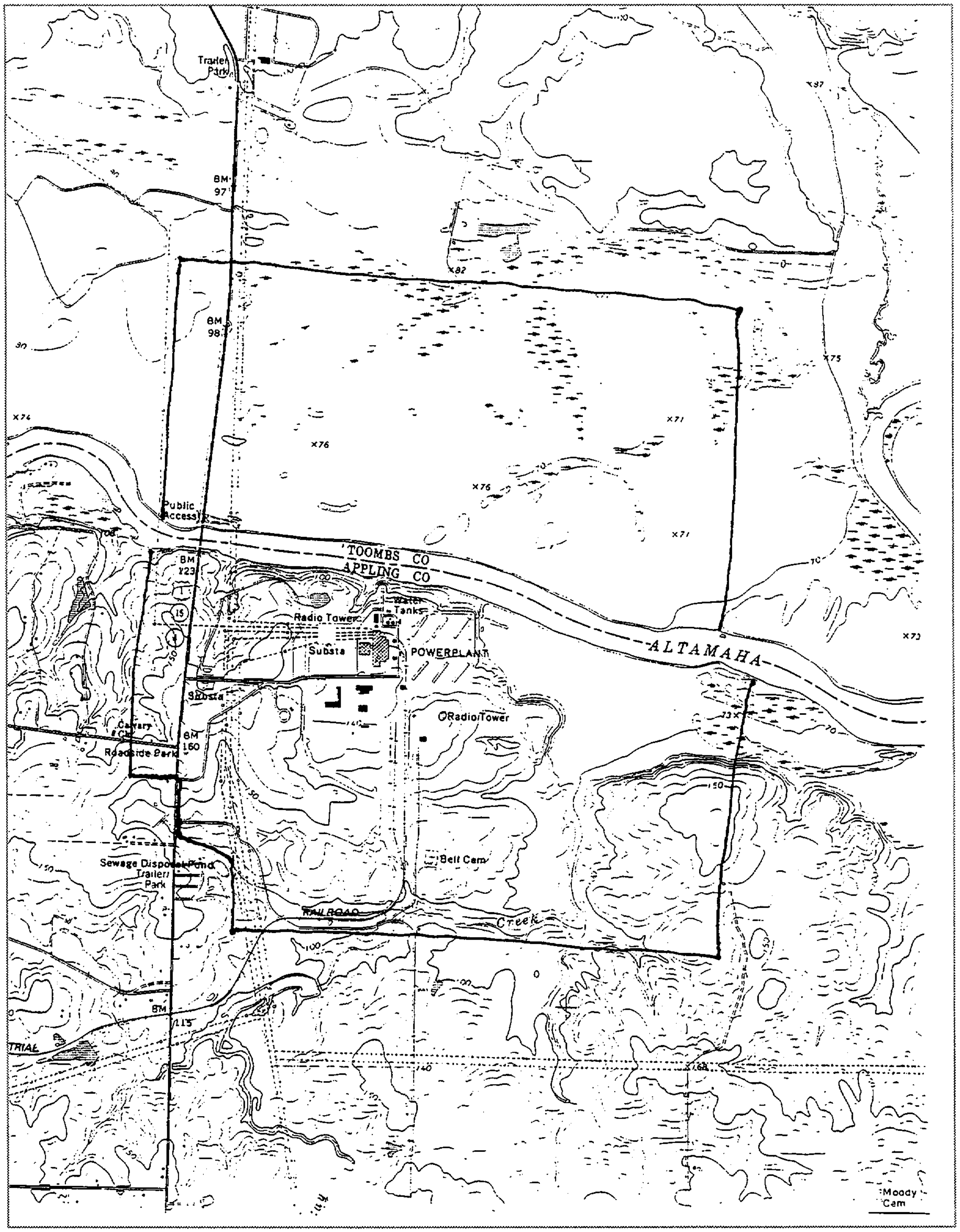
Southern Nuclear and Georgia Power Company appreciates your attention to processing this data request. If you need additional information, please contact me at 404-799-2151.

Sincerely,

William J. Candler

William J. Candler
Environmental Supervisor

Letter C-1. Georgia Department of Natural Resources letter (page 1 of 2).



Letter C-1. Georgia Department of Natural Resources letter (page 2 of 2).

Georgia Department of Natural Resources

Wildlife Resources Division

LONICE C. BARRETT, COMMISSIONER
DAVID WALLER, DIVISION DIRECTOR

Georgia Natural Heritage Program
2117 U.S. Hwy. 278 S.E., Social Circle, Georgia 30025-4714
(770) 918-6411, (706) 557-3032

February 27, 1998

William J. Candler
5131 Maner Road
Smyrna, Georgia 30080

Subject: **Known or Potential Occurrences of Special Concern Plant and Animal Species for Plant Hatch Extension, Bailey, Georgia**

Dear Mr. Candler;

This is in response to your request of February 6, 1998. According to our records, within a three mile radius of the project site, there are occurrences of the following:

Within the Project Area (Includes map location numbers. All locations are exact except *Alasmidonta arcula* which is within 1.5 miles of the location indicated on the map.)

Alasmidonta arcula (Altamaha arc-mussel), #5
Elliptio spinosa (Georgia spiny mussel), #4
Sideroxylon sp. 1 (Ohoopee bumelia), #1
Agrimonia incisa (Cutleaf agrimony), #2 & #3

1 Mile East of Project Area

Elliptio shepardiana (Altamaha lance)
Elliptio spinosa (Georgia spiney mussel)

1 Mile Southeast of Project Area

Picoides borealis (Red-cockaded woodpecker)
Aimophilia aestivalis (Bachman's sparrow)
Gopherus polyphemus (Gopher tortoise)
Krameria lanceolata (Sandbur)

3 Miles East of Project Area

Elliptio spinosa (Georgia spiny mussel)
Alasmidonta arcula (Altamaha arc-mussel)

Letter C-2. Georgia Department of Natural Resources letter (page 1 of 9).

Mr. William J. Candler
Page 2
February 11, 1998

Enclosed are potential animal and plant lists for Toombs County that should aid in assessing the potential for rare species occurrences within the area of concern.

Please keep in mind the limitations of our database. The data collected by the Georgia Natural Heritage Program comes from a variety of sources, including museum and herbarium records, literature, and reports from individuals and organizations, as well as field surveys by our staff biologists. In most cases the information is not the result of a recent on-site survey by our staff. Many areas of Georgia have never been surveyed thoroughly. Therefore, the Georgia Natural Heritage Program can only occasionally provide definitive information on the presence or absence of rare species on a given site. Our files are updated constantly as new information is received. Thus, information provided by our program represents the existing data in our files at the time of the request and should not be considered a final statement on the species or area under consideration.

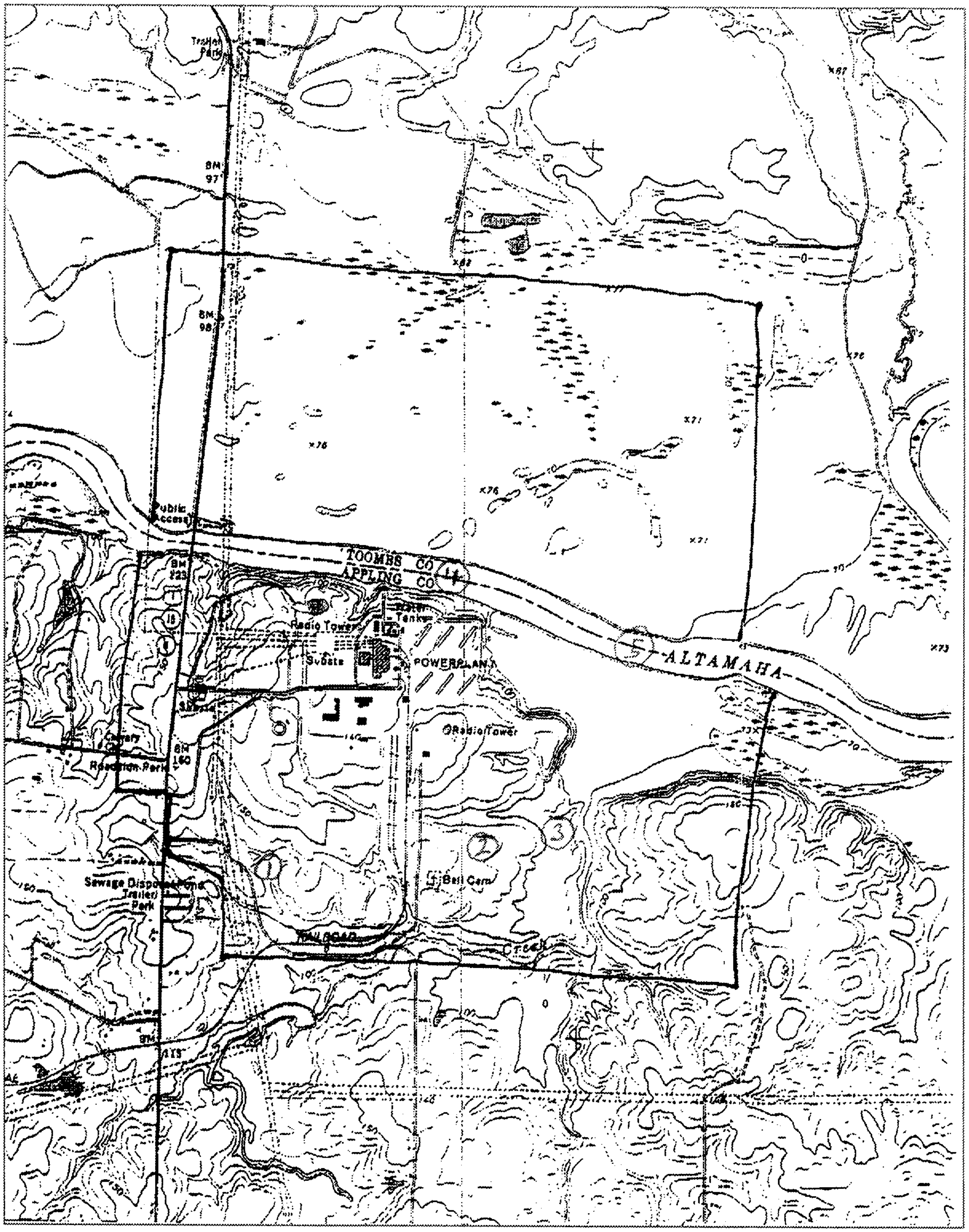
If I can be of further assistance, please let me know.

Sincerely,

Greg Krakow
Data Manager

GK/gk
enclosures

Letter C-2. Georgia Department of Natural Resources letter (page 2 of 9).



Letter C-2. Georgia Department of Natural Resources letter (page 3 of 9).

Page Number 1 of 3 Report Generated 27 February 1998

Special Concern Animals Potentially Occurring in Toombs County

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

Species Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Acantharchus pomotis MUD SUNFISH	G5	S3			Blackwater streams; bays; cypress/gum ponds
Acipenser brevirostrum SHORTNOSE STURGEON	G3	S2	LE	E	Brownwater rivers; tidal rivers; estuaries
Aimophila aestivalis BACHMAN'S SPARROW	G3	S3		R	Open pine or oak woods; old fields; brushy areas
Alasmidonta arcula ALTAMAHA ARC-MUSSEL	G1G2	S3			Altamaha River
Alosa alabamae ALABAMA SHAD	G4	S1		U	Brownwater & blackwater streams
Ambystoma cingulatum FLATWOODS SALAMANDER	G2G3	S3		R	Pine flatwoods; moist savannas; cypress/gum ponds
Ammodramus henslowii HENSLOW'S SPARROW	G3G4	S3			Fields; meadows
Anodonta couperiana BARREL FLOATER	G3G4	S?			Habitat data is not available
Anodonta gibbosa INFLATED FLOATER	G1G3	S3?			Habitat data is not available
Catharus fuscescens VEERY	G5	S4			Moist deciduous woods; streamside thickets
Cordulegaster sayi SAY'S SPIKETAIL	G1G2	S2			Habitat data is not available
Cyprinella callisema OCMULGEE SHINER	G3	S3			Blackwater & brownwater streams
Cyprinella leedsi BANNERFIN SHINER	G3	S3S4			Blackwater & brownwater streams
Drymarchon corais couperi EASTERN INDIGO SNAKE	G4T3	S3	LT	T	Sandhills; pine flatwoods; dry hammocks
Elanoides forficatus AMERICAN SWALLOW-TAILED KITE	G5	S2		R	River swamps; marshes
Elliptio dariensis GEORGIA ELEPHANT-EAR	G3	S3			Habitat data is not available
Elliptio hopetonesis ALTAMAHA SLABSHELL	G3	S4			Habitat data is not available
Elliptio shepardiana ALTAMAHA LANCE	G2	S4			Brownwater rivers
Elliptio spinosa GEORGIA SPINY MUSSEL	G1	S2			Altamaha River
Enneacanthus chaetodon BLACKBANDED SUNFISH	G5	S1S2		R	Blackwater streams; bays; cypress/gum ponds
Etheostoma parvipinne GOLDSTRIPE DARTER	G4G5	S2		R	Blackwater & brownwater streams; springs
Etheostoma serriferum SAWCHEEK DARTER	G5	S3			Blackwater & brownwater streams; lakes

Letter C-2. Georgia Department of Natural Resources letter (page 4 of 9).

Page Number 2 of 3 Report Generated 27 February 1998

Special Concern Animals Potentially Occurring in Toombs County

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

Species / Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Eumeces egregius MOLE SKINK	G4	S3			Coastal dunes; longleaf pine-turkey oak woods; dry hammocks
Eurycea longicauda LONGTAIL SALAMANDER	G5	S2			Moist woods near streams or springs; cave entrances
Falco peregrinus PEREGRINE FALCON	G4	S1	E(S/A)	E	Rocky cliffs & ledges; seacoasts
Falco sparverius paulus SOUTHEASTERN AMERICAN KESTREL	G5T3T4	S3			Pine forests; pine savannas
Farancia erytrogramma RAINBOW SNAKE	G5	S3			River swamps; springs; sandy fields near water
Fundulus chrysotus GOLDEN TOPMINNOW	G5	S3			Blackwater streams; ponds; bays; brackish streams
Gopherus polyphemus GOPHER TORTOISE	G3	S3		T	Sandhills; dry hammocks; longleaf pine-turkey oak woods
Haliaeetus leucocephalus BALD EAGLE	G4	S2	LTNL	E	Edges of lakes & large rivers; seacoasts
Heterodon simus SOUTHERN HOGNOSE SNAKE	G4G5	S3			Open, sandy woods; fields; floodplains
Hybognathus regius EASTERN SILVERY MINNOW	G5	S3?			Blackwater & brownwater streams
Kinosternon baurii STRIPED MUD TURTLE	G5	S3			River swamps; sloughs; ponds; marshes
Lampropeltis triangulum MILK SNAKE	G5	S2			Open woods; fields; forests
Lampsilis dolabraeformis ALTAMAHA POCKETBOOK	G2	S2?			Habitat data is not available
Lampsilis splendida RAYED PINK FATMUCKET	G3	S3?			Habitat data is not available
Lasiurus intermedius NORTHERN YELLOW BAT	G4G5	S2S3			Wooded areas near open water or fields
Limnothlypis swainsonii SWAINSON'S WARBLER	G4	S3S4			Habitat data is not available
Micrurus fulvius EASTERN CORAL SNAKE	G5	S3			Hardwood forests; pine flatwoods; dry hammocks; marshes
Mycteria americana heronry WOOD STORK	G4	S2	LENL	E	Cypress/gum ponds; marshes; river swamps; bays
Necturus punctatus DWARF WATERDOG	G4	S2			Blackwater streams
Notophthalmus perstriatus STRIPED NEWT	G2G3	S2		R	Pine flatwoods; ponds; ditches
Notropis harperi REDEYE CHUB	G4	S1		R	Springs & small streams
Nyctanassa violacea YELLOW-CROWNED NIGHT-HERON	G5	S3S4			River swamps; marshes; cypress/gum ponds

Letter C-2. Georgia Department of Natural Resources letter (page 5 of 9).

Page Number 3 of 3 Report Generated 27 February 1998

Special Concern Animals Potentially Occurring in Toombs County

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

GEORGIA

Species Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Nycticorax nycticorax BLACK-CROWNED NIGHT-HERON	G5	S3S4			River swamps; marshes; cypress/gum ponds
Ophisaurus attenuatus SLENDER GLASS LIZARD	G5	S3			Open woods; savannas; old fields; edges of streams & ponds; sandhills
Ophisaurus mimicus MIMIC GLASS LIZARD	G3	S2			Pine flatwoods
Pandion haliaetus OSPREY	G5	S3			Lakes; rivers; seacoasts
Picoides borealis RED-COCKADED WOODPECKER	G3	S2	LE	E	Open pine woods; pine savannas
Pituophis melanoleucus mugitus FLORIDA PINE SNAKE	G5T3?	S3			Upland forests; grasslands; floodplains; old field
Pseudotriton montanus MUD SALAMANDER	G5	S4			Swamps; muddy seeps; springs
Pteronotropis hypselopterus SAILFIN SHINER	G5	S3			Blackwater & brownwater streams
Rana capito GOPHER FROG	G4	S?	C		Floodplains; wet meadows; pastures; ponds
Sciurus niger shermani SHERMAN'S FOX SQUIRREL	G5T2	S?			Pine forests; pine savannas
Toxolasma pullus SAVANNAH LILLIPUT	G3	S2			Altamaha River; Savannah River
Villosa delumbis EASTERN CREEKSHELL	G3G4	S?			Habitat data is not available

Letter C-2. Georgia Department of Natural Resources letter (page 6 of 9).

Page Number 1 of 3 — Report Generated 14 January 1998

Special Concern Plants Potentially Occurring in Toombs County — 65 Taxa in List

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

Species Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Agalinis aphylla SCALE-LEAF PURPLE FOXGLOVE	G3G4	S2S3?			Longleaf pine-wiregrass savannas; pine flatwoods
Agalinis filicaulis SPINDLY PURPLE FOXGLOVE	G3G4	S2?			Seasonally wet, longleaf pine-wiregrass savannas; grassy pine barrens
Agrimonia incisa CUTLEAF AGRIMONY; CUTLEAF HARVEST LICE	G3	S3			Mixed oak-hickory forests, pine savannas, mesic hardwood forests
Amorpha georgiana var. georgiana GEORGIA INDIGO-BUSH	G3T2	S1			Fluvial terraces: pine-shrub-wiregrass terraces along rivers and major streams
Amphicarpum muehlenbergianum BLUE MAIDENCANE, FLORIDA GOOBER GRASS	G4	S3?			Pine flatwoods
Andropogon mohrii BOG BLUESTEM	G4?	S2?			Longleaf pine-wiregrass savannas; pine-cypress savannas
Apteria aphylla NODDING NIXIE	G4	S3			Mesic hardwoods or magnolia-beech bluff forests
Aristida condensata SANDHILL THREE-AWN GRASS	G4?	S3?			Sandridges
Astragalus michauxii SANDHILL MILKVETCH	G3	S2			Longleaf pine-wiregrass savannas; turkey oak scrub
Balduina atropurpurea PURPLE HONEYCOMB HEAD	G2G3	S2		R	Wet savannas, pitcherplant bogs
Calamintha ashei OHOOPEE DUNES WILD BASIL	G3	S2		T	Ohoopee dunes
Carex dasycarpa VELVET SEDGE	G4?	S3		R	Evergreen hammocks; mesic hardwood forests
Carex decomposita CYPRESS-KNEE SEDGE	G4	S2?			Swamps and lake margins on floating logs
Ceratiola ericoides ROSEMARY	G4	S2		T	Ohoopee Dunes; deep sandridges
Chrysoma pauciflosculosa WOODY GOLDENROD	G4G5	S3			Ohoopee dunes; sandridges
Delphinium carolinianum CAROLINA LARKSPUR	G5	S3			Granite outcrops; rocky, calcareous oak forests; Altamaha Grit outcrops
Elliottia racemosa GEORGIA PLUME	G2G3	S2S3		T	Scrub forests; Altamaha Grit outcrops; open forests over ultramafic rock
Epidendrum conopseum GREEN-FLY ORCHID	G3G4	S3		U	Epiphytic in bottomland hardwoods and magnolia-beech bluff forests, also Altamaha Grit outcrops
Evolvulus sericeus var. sericeus CREEPING MORNING-GLORY	G5T?	S1		E	Altamaha Grit outcrops; open calcareous uplands
Fothergilla gardenii DWARF WITCH-ALDER	G4	S2		T	Openings in low woods; swamps

Letter C-2. Georgia Department of Natural Resources letter (page 7 of 9).

Page Number 2 of 3 Report Generated 14 January 1998

Special Concern Plants Potentially Occurring in Toombs County 65 Taxa in List

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

GEORGIA

Species / Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Habenaria quinqueseta var. quinqueseta MICHAUX ORCHID	G4G5T?	S1			Moist shade, Altamaha Grit outcrops; open pine woods
Ilex amelanchier SERVICEBERRY HOLLY	G4	S2			Wet, sandy thickets; cypress-gum swamps
Ipomopsis rubra STANDING CYPRESS	G4G5	S3			Granite outcrops; sandridges
Isoetes melanopoda BLACK-FOOTED QUILLWORT	G5	S1?			Clayey soils in low woods; sandstone or granite outcrop seeps
Krameria lanceolata SANDBUR	G5	S3?			Longleaf pine-wiregrass sandridges
Lachnocaulon beyrichianum SOUTHERN BOG-BUTTON	G2G3	S1			Flatwoods
Lechea deckertii DECKERT PINWEED	G4G5	S1?			Scrub
Lechea torreyi TORREY PINWEED	G4G5	SU			Flatwoods; pond margins; scrub
Liatris pauciflora FEW-FLOWER GAY-FEATHER	G4G5	S2?			Sandridge scrub
Lindera melissifolia PONDBERRY	G2	S1	LE	E	Pond margins and wet savannas
Listera australis SOUTHERN TWAYBLADE	G4	S2			Poorly drained circumneutral soils
Litsea aestivalis PONDSPICE	G3	S2		T	Cypress ponds; swamp margins
Macranthera flammea FLAME FLOWER	G3	S2?			Wet, sandy thickets; pitcherplant bogs
Marshallia ramosa PINELAND MARSHALLIA	G2	S2		R	Altamaha Grit outcrops; open forests over ultramafic rock
Matelea flavidula YELLOW MILKVINE	G3	SU			Open bluff forests; floodplain forests
Matelea pubiflora TRAILING MILKVINE	G3G4	S2		R	Exposed sandy soils; sandridges
Nestronia umbellula INDIAN OLIVE	G4	S2		T	Oak-hickory-pine woods with heath understory; rocky or sandy woods;
Oxypolis ternata TERNATE COWBANE	G3	S2			Wet pine savannas and bogs
Penstemon dissectus GRIT BEARDTONGUE	G2?	S2		R	Altamaha Grit outcrops and adjacent pine savannas; rarely sandridges
Phaseolus polystachios var. sinuatus TRAILING BEAN-VINE	G4T3	S2?			Sandhills; dry pinelands and hammocks
Pieris phillyreifolia CLIMBING HEATH	G3?	S3			Cypress ponds; epiphytic on cypress bark
Platanthera integra YELLOW FRINGELESS ORCHID	G4	S2			Wet savannas, pitcherplant bogs
Platanthera nivea SNOWY ORCHID	G5	S3			Wet savannas, pitcherplant bogs

Letter C-2. Georgia Department of Natural Resources letter (page 8 of 9).

 Report Generated 14 January 1998

Special Concern Plants Potentially Occurring in Toombs County 65 Taxa in List

Georgia Natural Heritage Program, 2117 US Hwy 278 SE, Social Circle, GA 30025, (770) 918-6411

Species / Common Name	Global Rank	State Rank	Federal Status	State Status	Habitat
Polanisia tenuifolia SLENDERLEAF CLAMMY-WEED	G5	S3			Sandridges; scrub
Polygala leptostachys GEORGIA MILKWORT	G2G4	S1			Oak-pine scrub
Quercus austrina BLUFF WHITE OAK	G5	S3?			Bluff forests; floodplain hammocks
Rhynchospora culixa GEORGIA BEAKRUSH	G1	SH			Pine savannas; flatwoods
Rhynchospora punctata PINELAND BEAKRUSH	G1?	S1?			Wet savannas, pitcherplant bogs
Rudbeckia nitida var. nitida YELLOW CONEFLOWER	G3?T1T3	S3?			Wet savannas, pitcherplant bogs; cypress ponds
Sarracenia flava YELLOW FLYTRAP	G4G5	S3S4		U	Wet savannas, pitcherplant bogs
Sarracenia minor HOODED PITCHERPLANT	G4	S4		U	Wet savannas, pitcherplant bogs
Sarracenia psittacina PARROT PITCHERPLANT	G4	S2S3		T	Wet savannas, pitcherplant bogs
Sarracenia purpurea PURPLE PITCHERPLANT	G5	S1		E	Swamps, wet rhododendron thickets
Sarracenia rubra SWEET PITCHERPLANT	G3	S2		E	Atlantic white cedar swamps; wet meadows
Schizachyrium stoloniferum BLUESTEM	G3G4Q	S2?			Longleaf pine-wiregrass savannas
Scutellaria mellichampii SKULLCAP	G?	S1?			Sandy deciduous woods
Sideroxylon sp. 1 OHOOPEE BUMELIA	G2Q	S3?			Dry longleaf pine woods with oak understory
Silene caroliniana CAROLINA PINK	G5	S2?			Granite outcrops and sandhills near the Ogeechee and Savannah Rivers
Sium suave WATER-PARSNIP	G5	S2			Swamps
Sporobolus teretifolius WIRE-LEAF DROPSEED	G1G2	S2?			Longleaf pine-wiregrass savannas, pitcherplant bogs
Stewartia malacodendron SILKY CAMELLIA	G4	S2		R	Steepheads, bayheads; edges of swamps
Stylisma pickeringii var. pickeringii PICKERING MORNING-GLORY	G4?T2T3	S2		T	Open, dry, oak scrub of sandhills
Uvularia floridana FLORIDA BELLWORT	G3?	S3?			Mixed oak-hickory forests; mesic hardwoods or magnolia-beech bluff forests
Warea cuneifolia SANDHILL-CRESS	G4	S3			Sandhills scrub
Zigadenus leimanthoides DEATH-CAMUS	G4Q	S1			Sandhill bogs; pine flatwoods

Letter C-2. Georgia Department of Natural Resources letter (page 9 of 9).

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992 5000

SOUTHERN COMPANY
Energy to Serve Your World℠

September 15, 1999 LRS-99-001

U.S. Fish and Wildlife Service
Ecological Services Field Office
247 South Milledge Avenue
Athens, Georgia 30605

Attn: Ms. Sandra Tucker, Field Supervisor

Re: Request for "no effect" determination regarding License Renewal Activity.

Southern Nuclear Operating Company ("SNC") is preparing an application to renew the Edwin I. Hatch ("HNP") Nuclear Power Plant operating licenses consistent with the U.S. Nuclear Regulatory Commission ("NRC") regulations. This application would provide for an additional 20 years of operation beyond the current license term. As part of the license renewal process, the NRC requires applicants to identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities.

HNP Unit 1 began commercial operation December 31, 1974 and is licensed to operate through August 5, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed through June 13, 2018. The Plant is in Appling County, Georgia, approximately 11 miles north of the town of Baxley. HNP's six transmission lines cross 17 counties in the Coastal Plain of Georgia (see attached figure for details).

SNC recently conducted surveys of the HNP site and associated transmission line rights-of-way. No federally listed species were found on the plant site property, but several listed species were observed (or evidence of these species was found) in or adjacent to existing transmission line corridors. A report detailing the findings of the threatened and endangered species surveys is enclosed.

Page 1 of 3

Letter C-3. U.S. Fish and Wildlife Services letter (page 1 of 4).

LR-99-001
Re: Request for "no effect" determination regarding License Renewal Activity.
Page 2 of 3

Two federally-listed species not recorded in the 1998-1999 surveys, the threatened bald eagle and endangered wood stork, have been observed by Georgia Power Company biologists and natural resources managers in the general area of the Plant, but neither species is believed to nest in the vicinity of the Plant. Bald eagles have been seen foraging along the Altamaha River upstream and downstream of HNP. Wood storks have been observed in a beaver pond wetland just east of the HNP cooling towers.

In addition to the surveys of terrestrial plants and animals, SNC conducted a freshwater mussel survey in a 12-mile reach of the Altamaha River up and downstream of HNP in September 1998. Collections were dominated by species that are endemic to the Altamaha River system and species that are considered "Species of Concern" by the USFWS and Georgia DNR because the status of their populations is not known. None of the mussel species collected were state or federally-listed. A copy of the *Freshwater Mussel Survey: Altamaha River/Appling and Toombs Counties, Georgia* is enclosed. Note that a copy of this survey has already been sent to Mr. Greg Masson of your Brunswick office.

SNC is committed to the conservation of significant natural habitats and protected species, and expects that operation of the Plant through the license renewal period (an additional 20 years) would not adversely affect any listed species. Thus, SNC has no plans to alter current operations for the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. The license renewal would not constitute a "major construction activity" because no expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. Accordingly, we request your concurrence with our determination that a renewed license would have no effect on listed or proposed endangered or threatened species and that formal consultation is not necessary.

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by October 22, 1999 to enable us to meet our application preparation schedule.

Sincerely,

C R Pierce

C. R. Pierce
License Renewal Services Manager

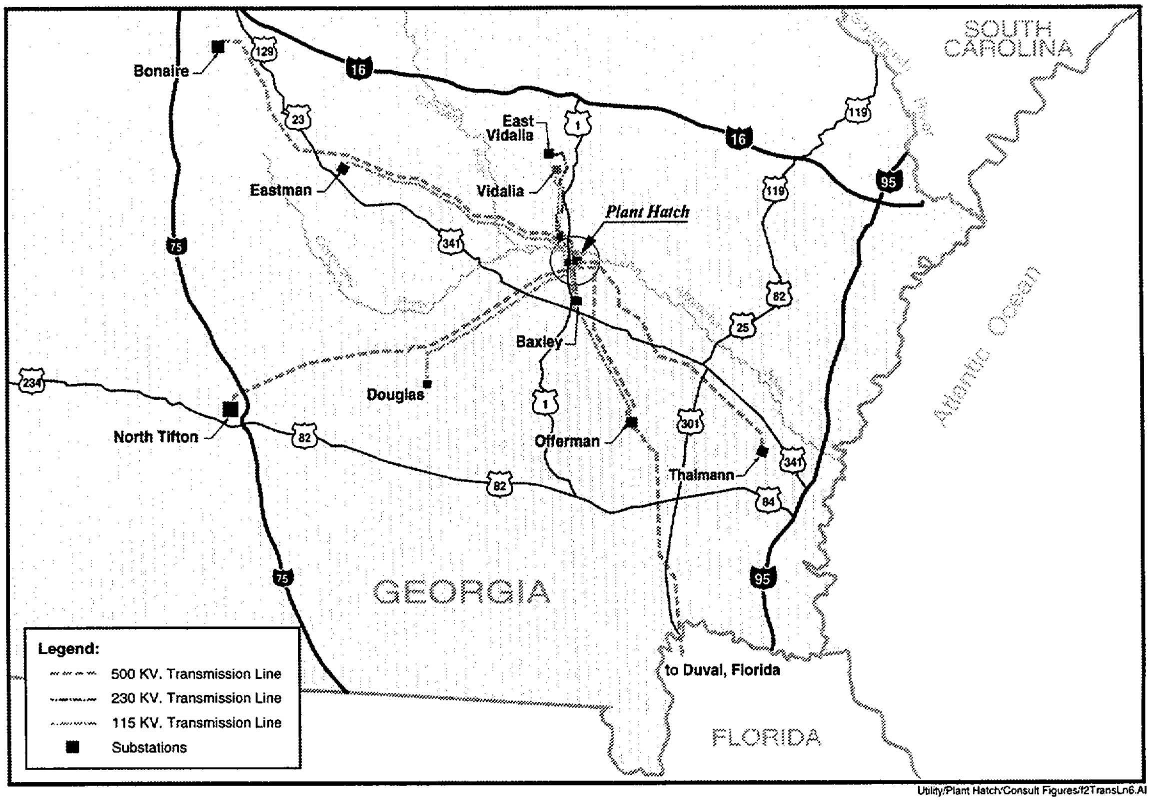
CRP/JTD
Attachment

Letter C-3. U.S. Fish and Wildlife Services letter (page 2 of 4).

LR-99-001
Re: Request for "no effect" determination regarding License Renewal Activity.
Page 3 of 3

CC: Greg Masson, USFWS – Brunswick
Mark Bowers, USFWS – Piedmont NWR
P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter C-3. U.S. Fish and Wildlife Services letter (page 3 of 4).



Edwin I. Hatch Nuclear Plant Transmission Lines.

Letter C-3. U.S. Fish and Wildlife Services letter (page 4 of 4).

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

September 15, 1999

LRS-99-002

National Marine Fisheries Service
Southeast Regional Office
9721 Executive Center Drive North
St. Petersburg, Florida 33702

Attn: Mr. Charles Oravetz, Chief, Protected Species Branch

Re: Request for "no effect" determination regarding License Renewal Activity.

Southern Nuclear Operating Company ("SNC") is preparing an application to renew the Edwin I. Hatch ("HNP") Nuclear Power Plant operating licenses consistent with the U.S. Nuclear Regulatory Commission ("NRC") regulations. This application would provide for an additional 20 years of operation beyond the current license term. As part of the license renewal process, the NRC requires applicants to identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities.

NRC guidance directs license applicants to consult with the appropriate agency to determine whether threatened or endangered species are present and whether they would be adversely affected by the proposed action.

HNP Unit 1 began commercial operation December 31, 1974, and is licensed to operate through August 6, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed through June 13, 2018. The Plant is in Appling County, Georgia, approximately 11 miles north of the town of Baxley. Generating facilities for HNP lie on the south bank of the Altamaha River, just east of U.S. Highway 1 (see attached figures). The Altamaha River is approximately 500 feet wide and as deep as 30 feet in the area of HNP, and is bordered by a mature floodplain forest.

Page 1 of 3

Letter C-4. National Marine Fisheries Service letter (page 1 of 5).

LR-99-002
RE: Request for "no effect" determination regarding License Renewal Activity.
Page 2 of 3

One Federally listed aquatic species, the anadromous shortnose sturgeon (*Acipenser brevirostrum*) is known to occur in the Altamaha River in the vicinity of Plant Hatch. The *Final Environmental Statement* (FES) *Related to Operation of Edwin I. Hatch Nuclear Plant Unit No. 2* (NRC 1978) reported that one adult shortnose sturgeon and three larval sturgeon were collected during three years (1972-1975) of pre- and post-operational monitoring in the Altamaha River near the Plant. The NRC concluded in the FES that losses of adult fish (due to impingement) and ichthyoplankton (due to entrainment) as a result of operation of both units of HNP would not be significant. The NRC also concluded that the thermal (discharge) plume would not present a barrier to migrating fish, including the shortnose sturgeon because the thermal plume would be small and restricted to a surface layer.

Additional studies conducted by Georgia Power in 1974, 1975, 1976, 1979, and 1980 (summarized in the Plant Hatch 316(b) Demonstration, dated March 1981) confirmed that the operation of two nuclear units at HNP has minimal impact on fish populations in the Altamaha River. No shortnose sturgeons were collected in these impingement and entrainment studies. Annual impingement rate estimates ranged from 146 fish per year to 438 fish per year. The hogchoker, *Trinectes maculatus*, was the species most often impinged and the only species collected every year in impingement samples. Estimated entrainment losses of fish, larvae, and eggs were less than one percent of the total number present in 1974, 1975, 1976, 1979, and 1980 spawning seasons, with the exceptions of three months (July, August, and September) in 1980. This was a period when a severe drought dramatically reduced river flows. It should be noted that all of the anadromous fish species that are found in the Altamaha including the shortnose sturgeon would have completed their spawning runs by late summer and would not normally be affected by these low river conditions. Catostomids, cyprinids, and centrarchids dominated the entrainment samples.

SNC is committed to the conservation of significant natural habitats and protected species, and expects that operation of the Plant through the license renewal period (an additional 20 years) would not adversely affect any listed species, including the shortnose sturgeon. SNC has no plans to alter current patterns of operation over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no major structural modifications are anticipated in support of license renewal. We therefore request your concurrence with our determination that the license renewal would have no effect on listed or proposed endangered or threatened species and that formal consultation is not necessary.

Letter C-4. National Marine Fisheries Service letter (page 2 of 5).

LR-99-002
RE: Request for "no effect" determination regarding License Renewal Activity.
Page 3 of 3

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by October 22, 1999, to enable us to meet our application preparation schedule. SNC will include a copy of this letter and your response in the Environmental Report that will be submitted as part of the HNP license renewal application should we decide to request renewal.

Sincerely,

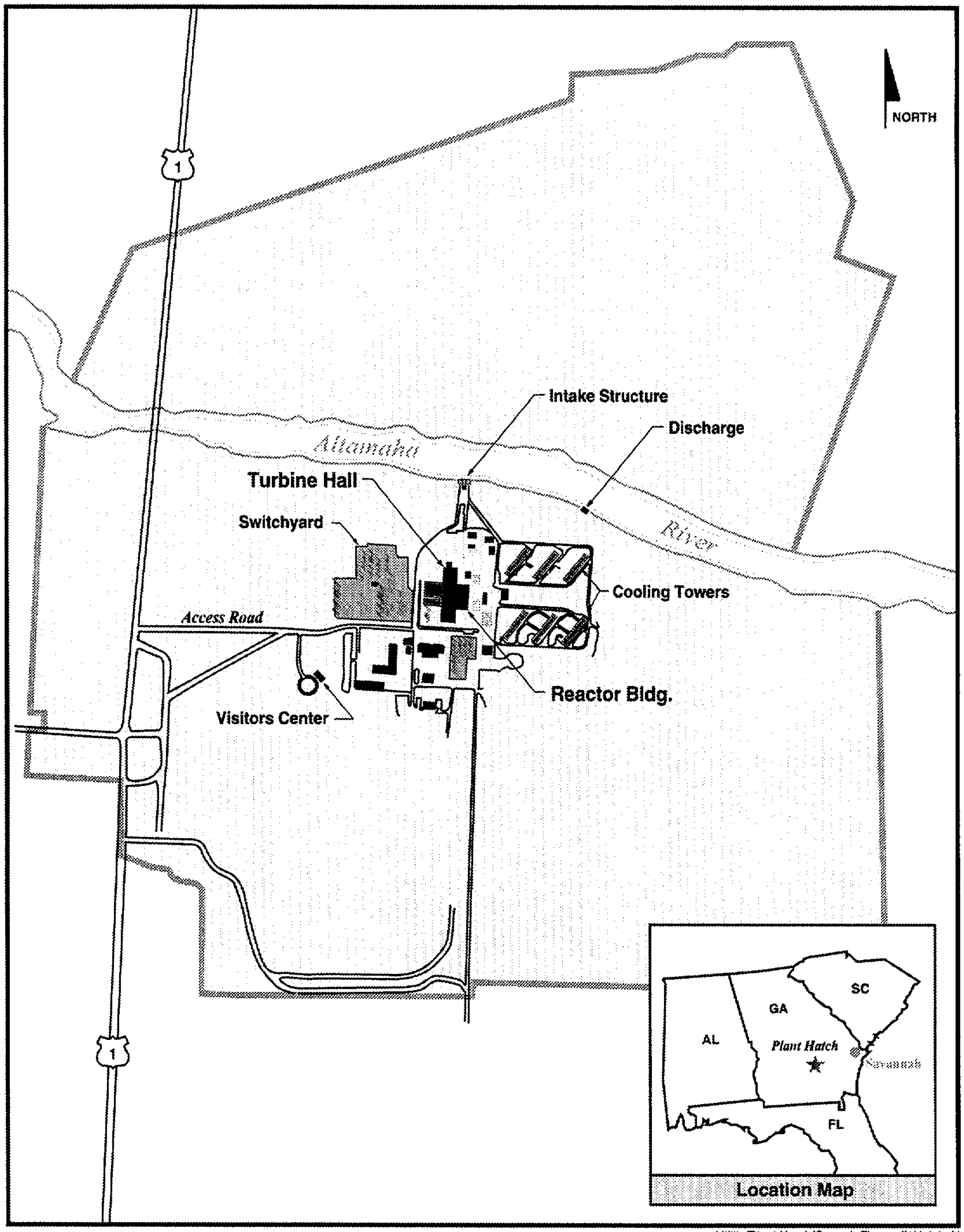
C. R. Pierce
License Renewal Services Manager

CRP/JTD

Attachment

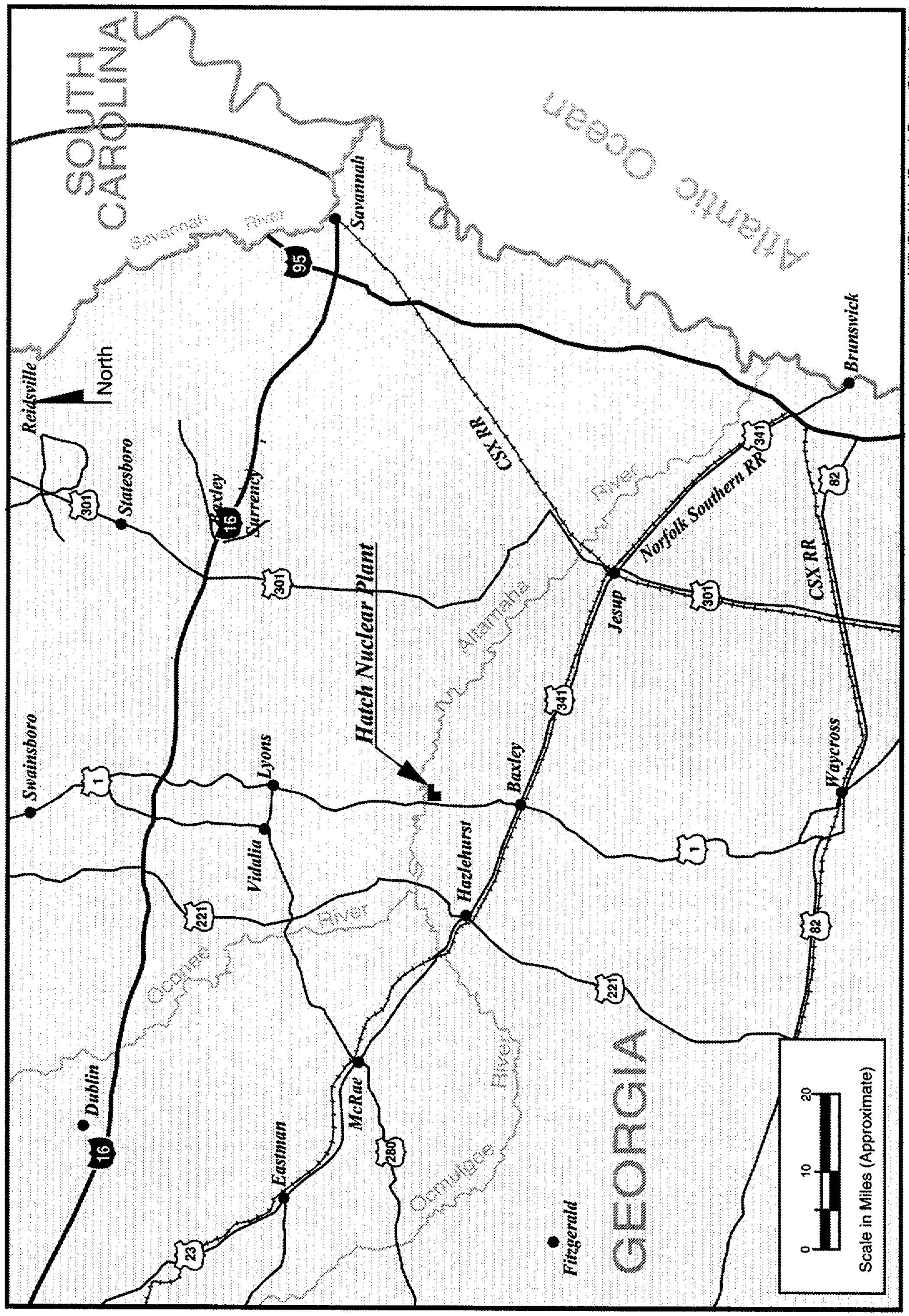
cc: P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter C-4. National Marine Fisheries Service letter (page 3 of 5).



Edwin I. Hatch Nuclear Plant Site.

Letter C-4. National Marine Fisheries Service letter (page 4 of 5).



Utility/Plant Hatch/Consult Figures/F2-1 50-mile.ai

Edwin I. Hatch Nuclear Plant , 50-mile region.

Letter C-4. National Marine Fisheries Service letter (page 5 of 5).

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

September 15, 1999

LR-99-005

Wildlife Resources Division
Georgia Department of Natural Resources
2070 U.S. Highway 278 SE
Social Circle, Georgia 30025

Attn: Mr. David Waller, Director

Re: E.I. Hatch Nuclear Plant Threatened and Endangered Species Surveys

Southern Nuclear Operating Company ("SNC") is preparing an application to renew the Edwin I. Hatch ("HNP") Nuclear Power Plant operating licenses consistent with the U.S. Nuclear Regulatory Commission ("NRC") regulations. This application would provide for an additional 20 years of operation beyond the current license term. As part of the license renewal process, the NRC requires applicants to identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or refurbishment activities.

HNP Unit 1 began commercial operation December 31, 1974, and is licensed to operate through August 5, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed through June 13, 2018. The Plant is in Appling County, Georgia, approximately 11 miles north of the town of Baxley. HNP's six transmission lines cross 17 counties in the Coastal Plain of Georgia (see attached figures for details).

SNC recently conducted surveys of the HNP site and associated transmission line rights-of-way. These surveys were conducted in accordance with the *Edwin I. Hatch Nuclear Plant Environmental Field Survey Plan*, a copy of which was submitted to your organization for comment in September 1998. No federally-listed species were found on the plant site property, but several state and federally-listed species were observed (or evidence of these species was found) in or adjacent to existing transmission line corridors. A report detailing the findings of the threatened and endangered species surveys is enclosed.

Page 1 of 3

Letter C-5. Wildlife Resources Division letter (page 1 of 5).

LR-99-005
RE: E.I. Hatch Nuclear Plant Threatened and Endangered Species Surveys
Page 2 of 3

Two federally-listed species not recorded in the 1998-1999 surveys, the threatened bald eagle and endangered wood stork, have been observed by Georgia Power Company biologists and natural resources managers in the general area of the Plant, but neither species is believed to nest in the vicinity of the Plant. Bald eagles have been seen foraging along the Altamaha River upstream and downstream of HNP. Wood storks have been observed in a beaver pond wetland just east of the HNP cooling towers.

In addition to the surveys of terrestrial plants and animals, SNC conducted a freshwater mussel survey in a 12-mile reach of the Altamaha River up and downstream of HNP in September 1998. Collections were dominated by species that are endemic to the Altamaha River system and species that are considered "Species of Concern" by the USFWS and Georgia DNR because the status of their populations in not known. None of the mussel species collected were state or federally-listed. A copy of the *Freshwater Mussel Survey: Altamaha River/Appling and Toombs Counties, Georgia* is enclosed. Note that a copy to this survey has already been sent to Mr. Bert Deener of your Waycross office.

SNC is committed to the conservation of significant natural habitats and protected species, and expects that operation of the Plant through the license renewal period (an additional 20 years) would not adversely affect any listed species. SNC has no plans to alter current operations for the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously-disturbed areas. The license renewal would not constitute a "major construction activity" because no expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. Accordingly, we ask that you provide comments on the survey reports and concurrence with our determination that license renewal is not likely to have an adverse impact on threatened and endangered species.

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by October 22, 1999, to enable us to meet our application preparation schedule.

Sincerely,

C. R. Pierce
License Renewal Services Manager

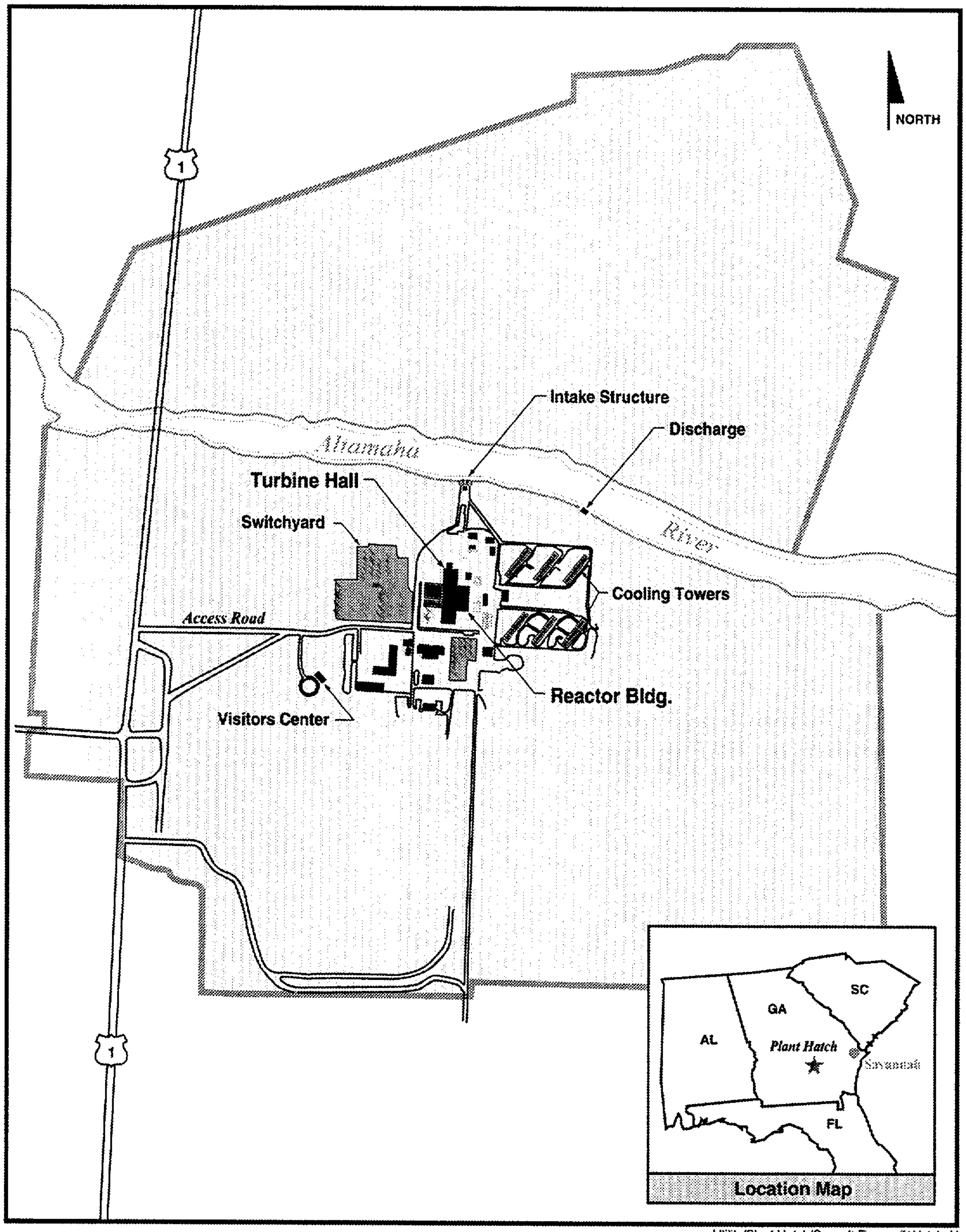
CRP/JTD
Enclosure

Letter C-5. Wildlife Resources Division letter (page 2 of 5) .

LR-99-005
RE: E.I. Hatch Nuclear Plant Threatened and Endangered Species Surveys
Page 3 of 3

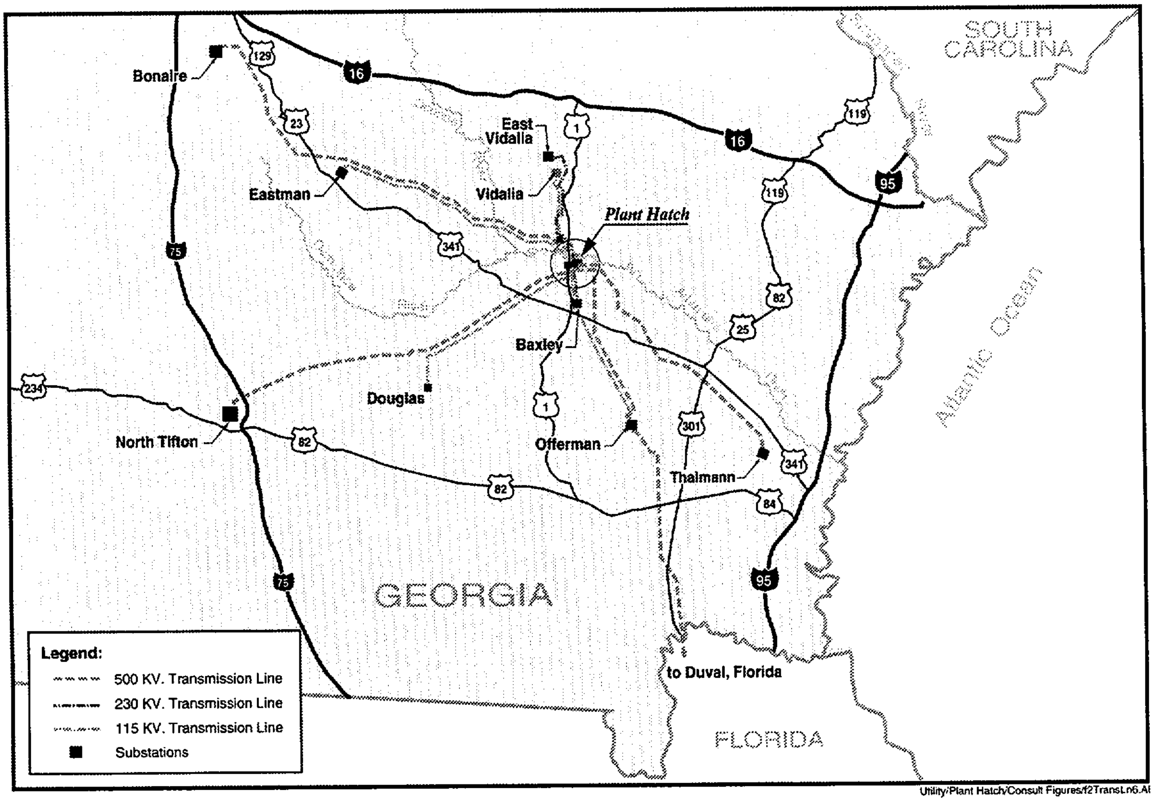
Cc: Bert Deener, Georgia DNR
P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter C-5. Wildlife Resources Division letter (page 3 of 5) .



Edwin I. Hatch Nuclear Plant Site.

Letter C-5. Wildlife Resources Division letter (page 4 of 5) .



Edwin I. Hatch Nuclear Plant Transmission Lines.

Letter C-5. Wildlife Resources Division letter (page 5 of 5) .

United States Department of the Interior

U.S. FISH AND WILDLIFE SERVICE
247 South Milledge Avenue
Athens, Georgia 30605

West Georgia Sub Office
P.O. Box 52560
Ft. Benning, Georgia 31995-2560

November 8, 1999

Coastal Sub Office
4270 Norwich Street
Brunswick, Georgia 31520

C.R. Pierce,
License Renewal Services Manager
Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, Alabama 35201
Attn: Mr. Jim Davis

Re: FWS Log No. 99-0887

Dear Mr. Pierce:

The U.S. Fish and Wildlife Service (Service) has reviewed your letter dated September 15, 1999, requesting concurrence with Southern Nuclear Operating Company's "no effect" determination with regard to potential impacts to threatened and endangered species associated with license renewal at the Edwin I. Hatch Nuclear Power Plant (Plant Hatch) located on the Altamaha River near the town of Baxley, Appling County, Georgia. Additional information requested by our office during discussions with Mr. Mike Nichols of Georgia Power Company was provided to our office by letter dated October 8, 1999, and included the following supporting materials: U.S. Nuclear Regulatory Commission (NRC) Draft Regulatory Guidance (DG-4005, July, 1998), request for threatened and endangered species information (December 16, 1997), completed threatened and endangered species surveys for Plant Hatch Extension (February 27, 1998), and Sections 2 and 5 of the Environmental Statement for Operation of Plant Hatch (March, 1978). We provide the following comments in accordance with Section 7 of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.).

We are unable to concur with Souther Nuclear Operating Company's determination of "no effect" regarding license renewal. In order to adequately evaluate natural resource impacts associated with the operation of Plant Hatch, we recommend that the NRC and Southern Nuclear evaluate additional relative information must be reviewed including; (1) any reports concerning actual operations at the facility since initial licensing, (2) any operations that may differ from those described in the initial license, (3) any operations that may differ from those described in the initial environmental reviews, (4) proposed or anticipated plant modifications or operational changes, (5) any Notices of Violation (NOV's) concerning operations, maintenance, releases of hazardous materials or exeedences in regulated discharges. In addition, any recorded data concerning actual intake velocities, discharge rates, chemical constituents in the actual discharges, accidents or spills, and any spill contingency plans should be provided. Thermal

1

Letter C-6. USFWS Letter, November 8, 1999 (page 1 of 3).

discharges should also be characterized and evaluated since the initial reviews in the 1970's relied heavily on modeled predictions and not actual measurements.

The Service is concerned about the potential entrainment of anadromous species and sensitive aquatic species at plant intake structures located in the Altamaha River, and recommends that effective methods to reduce entrainment of fishery resources at the project be evaluated. Entrainment reduction may include incorporation of the best scientifically developed technology available. However, some evaluation of the actual entrainment occurring at the project may also be necessary to quantify impacts to fishery resources due to the unique characteristics of the intake structures.

Many changes in water quality and quantity have occurred since the initial licensing of Plant Hatch. The Service is concerned that excessive thermal discharges may have adverse impacts on water quality and the aquatic environments of the Altamaha River. Of particular concern are high water temperatures and low dissolved oxygen concentrations due to increased Biological Oxygen Demand (BOD) resulting from significantly increased wastewater discharges.

We would encourage Souther Nuclear to further investigate the potential occurrence of the federally threatened flatwoods salamander, (Ambystoma cingulatum), in the vicinity of Plant Hatch and associated transmission line corridors. The flatwoods salamander is known from areas geographically close to Plant Hatch and the Service believes that suitable habitat may exist on the main facility property or within the transmission line corridors. Additionally, information concerning methods used to maintain transmission line corridors (mechanical and chemical) should be discussed and evaluated.

Concurrent to our discussions of potential impacts to natural resources under federal purview, we would strongly encourage Southern Nuclear to coordinate closely with the Georgia Department of Natural Resources, Wildlife Resources Division concerning impacts to aquatic resources of the Altamaha River. Additionally, Section 7 consultation should be initiated with the National Marine Fisheries Service, Protected Species Branch concerning potential impacts to the federally endangered shortnose sturgeon, (Acipencer brevirostrum).

We appreciate the opportunity to be involved in early planning stages of the license renewal process for the Edwin I. Hatch Nuclear Power Plant. While recognizing our statutory obligations to protect federal trust resources, we look forward to working with you in developing a timely license application that reflects Southern Nuclear's committment to protecting the environment. If you should have any questions or require addtitional information, please contact Mr. Mark D. Bowers of my staff at (912) 986-3066.

Sincerely,

Sandra S. Tucker

Sandra S. Tucker
Field Supervisor

Letter C-6. USFWS Letter, November 8, 1999 (page 2 of 3).

cc:
U.S. EPA, Atlanta, GA
GADNR-EPD, Atlanta, GA
GADNR-WRD, Social Circle, GA
NMFS, Charleston, SC
NMFS, Panama City, FL
FWS, GA ES, Brunswick, GA
Altamaha River Keeper
The Nature Conservancy, Darien, GA

3

Letter C-6. USFWS Letter, November 8, 1999 (page 3 of 3) .

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

December 7, 1999

LRS-99-008

U.S. Fish and Wildlife Service
Ecological Services Field Office
247 South Milledge Avenue
Athens, Georgia 30605

Attn: Ms. Sandra Tucker, Field Supervisor

Re: FWS Log No. 99-0887

Southern Nuclear Operating Company (SNC) is preparing an application to renew the Edwin I. Hatch Nuclear Plant operating licenses in accordance with Nuclear Regulatory Commission (NRC) regulations. As part of this process, the NRC requires applicants to identify adverse impacts to threatened and endangered species resulting from the continued operation of the facility.

By letters dated September 15, 1999 and October 4, 1999, respectively, SNC provided U.S. Fish and Wildlife Service (USFWS) with reports and other pertinent information assessing the potential impacts of license renewal on threatened and endangered species for review. The information concluded that license renewal would have no significant effect on listed or proposed endangered or threatened species and that formal consultation under Section 7 of the Endangered Species Act was not necessary. USFWS responded by letter dated November 2, 1999, that USFWS could not concur based on the information provided by SNC without clarification of certain issues that were noted in the referenced correspondence.

SNC met with Mr. Mark Bowers of your staff on November 30, 1999, in order to clarify the issues noted in the November 2, 1999 letter, and develop a thorough understanding of the information necessary for USFWS to complete an assessment of the potential impacts to threatened and endangered species associated with license renewal. Based on discussions with Mr. Bowers, the following additional information is provided in response to the issues outlined in your November 2, 1999 letter.

Letter C-7. SNC Letter to USFWS, December 7, 1999 (page 1 of 10) .

LRS-99-008
Page 2 of 3

The USFWS November 2, 1999 letter recommended that specific information be evaluated relative to the relicensing of Plant Hatch including: (1) reports concerning actual operation of the facility since initial licensing; (2) operations differing from those described in the initial licensing, and environmental reviews; (3) proposed or anticipated plant modifications or operational changes; (4) notice of violations (NOVs) associated with environmental permits and regulations; and (5) recorded data concerning intake velocities, discharge rates, chemical constituents of discharges, spills, and spill contingency plans. USFWS also recommended that thermal discharges be carefully evaluated.

This information is provided to NRC on an ongoing basis. Most of it is provided in accordance with the requirements of Appendix B of the current NRC operating license, known as the Environmental Protection Plan (EPP). The EPP requires the licensee to evaluate changes in plant design or operation with potential for impact to the environment, and inform the NRC of incidents such as spills or permit exceedances that result in significant environmental impact. 10 CFR Section 51.53(c) identifies the environmental information that must be submitted with the license renewal application in the form of an environmental report. The NRC will review the environmental report and relevant historical information in development of the Final Environmental Impact Statement for license renewal.

Thermal discharge information for two-unit operation was provided to Mr. Bowers and discussed in detail in the November 30, 1999 meeting. The "Thermal Plume Model Verification" (Attachment B) documents the field study that was performed to verify the accuracy of the model predicted plume described in the Environmental Impact Statement. The model and field verification demonstrate that thermal discharge to the river does not create thermal blockage or result in significant elevation of water temperature in the Altamaha River.

In the November 2, 1999 letter, USFWS, also indicated a concern with potential impingement and entrainment of sensitive aquatic species by the plant intake structure. This issue was discussed in detail with Mr. Bowers. Accordingly SNC provided copies of the 316(b) demonstration study (Attachment C) which includes five years of impingement data and three years of entrainment data. The study conclusively demonstrates that impingement and entrainment of sensitive aquatic species is not an issue for the Plant Hatch intake structure. SNC has determined that continued operation of Edwin I. Hatch Nuclear Plant is "not likely to adversely affect" sensitive aquatic species from entrainment or impingement.

In the November 2, 1999 letter, USFWS also expressed a concern related to the need for further investigation of the potential occurrence of the federally threatened flatwoods salamander (Ambystoma cingulatum) in the vicinity of Plant Hatch. The flatwoods salamander habitat and occurrence were evaluated in the Threatened and Endangered Species Survey provided in previous correspondence. The conclusion of this survey report has been revised to note that flatwoods salamander habitat can possibly occur

Letter C-7. SNC Letter to USFWS, December 7, 1999 (page 2 of 10).

LRS-99-008
Page 3 of 3

adjacent to or within the transmission corridors. The "Biological Information Update, Edwin I. Hatch Nuclear Plant, License Renewal" (Attachment A) discusses the flatwoods salamander habitat and the impact of maintenance activities within the transmission corridors. SNC has determined that continued operation of Edwin I. Hatch Nuclear Plant is "not likely to adversely affect" the flatwoods salamander.

Lastly, USFWS encouraged SNC to consult with Georgia Department of Natural Resources, Wildlife Services Division, and National Marine Fisheries Service (NMFS), Protected Species Branch relative to the potential impacts from license renewal on the shortnose sturgeon (Acipenser brevirostrum). SNC has formally contacted both agencies and is currently engaged in discussions relative to impact of license renewal on the shortnose sturgeon with NMFS. A copy of the "Biological Information Update, Edwin I. Hatch Nuclear Plant, License Renewal" developed by SNC discusses the shortnose sturgeon and is provided for your information as Attachment A.

We appreciate your efforts in developing the information necessary to analyze threatened and endangered species issues associated with Plant Hatch license renewal. SNC request, that USFWS provide concurrence letter upon the completion of your review of this additional material.

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by December 17, 1999 to enable us to meet our application preparation schedule.

Sincerely,

C. R. Pierce

C. R. Pierce
License Renewal Services Manager

CRP/JTD
Attachments

CC: Greg Masson, USFWS – Brunswick
Mark Bowers, USFWS – Piedmont NWR
David Bernhart, NMFS – St. Petersburg
P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter C-7. SNC Letter to USFWS, December 7, 1999 (page 3 of 10).

Biological Information Update
Edwin I Hatch Nuclear Plant
License Renewal

Letter C-7. Attachment (page 4 of 10) .

Table of Contents

Letter C-7. Attachment (page 5 of 10) .

I. INTRODUCTION

The purpose of this report is to provide additional information concerning Edwin I. Hatch Nuclear Plant to address questions raised by U. S. Fish and Wildlife Services concerning the Flatwoods Salamander and the Shortnose Sturgeon. The report summarizes plant information and existing data related to the Flatwoods Salamander and the Shortnose Sturgeon.

II. PROPOSED ACTION

The proposed action is the renewal of existing NRC operating licenses NPF-5 and DPR-57 for Edwin I. Hatch Nuclear Plant Units 1 and 2 respectively. HNP Unit 1 began commercial operation December 31, 1974, and is licensed to operate through August 6, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed to operate through June 13, 2018. NRC regulations (10 CFR Part 54) allow license renewal for periods of up to 20 years, which would extend the operation of Unit 1 to August 6, 2034 and extend the operation of Unit 2 to June 13, 2038.

III. SITE DESCRIPTION

The Edwin I. Hatch Nuclear Plant (HNP) is a steam-electric generating facility operated by Southern Nuclear Operating Company (SNC). HNP is located in Appling County, Georgia southeast of where U.S. Highway 1 crosses the Altamaha River. It is approximately 11 miles north of Baxley, Georgia; 98 miles southeast of Macon, Georgia; 73 miles northwest of Brunswick, Georgia; and 67 miles southwest of Savannah, Georgia. The Universal Transverse Mercator coordinates of the Unit 2 reactor (to the nearest 100 meters) are Zone 17R LF 3,533,700 meters North and 372,900 meters East. These coordinates correspond to latitude 31 degrees, 56 minutes, and 4 seconds North and longitude 82 degrees, 20 minutes, and 39 seconds West.

HNP is a two-unit plant. Each unit is equipped with a General Electric Nuclear Steam Supply System that utilizes a boiling-water reactor with a Mark I containment design. Both units were originally rated at 2,436 megawatt-thermal and designed for a power level corresponding to approximately 2,537 megawatt-thermal. Both units are now licensed for 2,763 megawatt-thermal (63 FR 53473-53478, October 5, 1998). The Plant withdraws water for cooling from the Altamaha River via shoreline intake and discharges via offshore discharge structures. Main Condenser cooling is provided by closed loop mechanical draft cooling towers. Descriptions of HNP can be found in documentation submitted to U.S. Nuclear Regulatory Commission (NRC) for the original operating license and subsequent license amendments. Georgia Power Company (GPC) submitted environmental reports for the construction stage and operating license stage for HNP in 1971 and 1976, respectively (References 1 and 2). In 1972, the Atomic Energy Commission (AEC)[1] issued a Final Environmental Statement (FES) for Units 1 and 2 (Reference 3), and in 1978 issued a FES for Unit 2 (Reference 4). The FES evaluates the environmental impacts from plant construction and operation in accordance with the National Environmental Policy Act (NEPA).

The excess heat produced by HNP's two nuclear units is absorbed by cooling water flowing through the condensers and the service water system. As stated above, main condenser cooling is provided by mechanical draft cooling towers. Each HNP circulating water system is a closed-loop cooling system that utilizes three (3) cross-flow mechanical-draft cooling towers and one (shared) counter-flow mechanical-draft cooling tower for dissipating waste heat to the atmosphere.

Letter C-7. Attachment (page 6 of 10) .

1. Predecessor agency to NRC.

SNC is permitted by Georgia DNR (GADNR Permit 001-0690-01) to withdraw surface water for cooling and other uses. For both Units, cooling water is withdrawn from the Altamaha River through a single intake structure. The intake structure is located along the southern shoreline of the Altamaha River and is positioned so that water is available to the plant at both minimum flow and probable flood conditions. The main river channel is located closer to the northern shoreline. The intake is approximately 150 feet long, 60 feet wide, and approximately 60 feet above normal river level. The water passage entrance is about 27 feet wide and extends from 16 feet below to 33 feet above normal water levels. Large debris is removed by trash racks, while small debris is removed by vertical traveling screens with a 3/8-inch mesh. As a condition of its permit, SNC is required to monitor and report withdrawals. HNP withdraws an annual average of 57.18 million gallons per day (88 cfs).

Water is returned to the Altamaha River via a submerged discharge structure that consists of two 42-inch lines extending approximately 120 feet out from the shore at an elevation of 54 feet mean sea level. The point of discharge is approximately 1,260 feet down-river from the intake structure and approximately 4 feet below the surface when the river is at its lowest level. The U. S. Nuclear Regulatory Commission developed a model which predicted the average expected thermal conditions and extreme thermal conditions under conservative assumptions in the E. I. Hatch Unit 1 and 2 Environmental Impact Statement. They independently noted the small size of the thermal plume even under conservative assumptions, and the lack of the possibility of thermal blockage in the Altamaha River from the plant discharge (Reference 3). The predictive thermal plume model was field-verified during 1980 following commencement of Unit 2 operation (Reference 7).

The National Pollutant Discharge Elimination System (NPDES) Permit for HNP (GA0004120) issued by the Environmental Protection Division (EPD) of the Georgia Department of Natural Resources (GA DNR) in 1997 requires weekly monitoring of discharge temperatures. The permit does not contain temperature limits.

GPC built six transmission lines for the specific purpose of connecting HNP to the transmission system. In total, for the specific purpose of connecting HNP to the transmission system, HNP has approximately 340 miles of transmission line corridors that occupy approximately 7,200 acres. GPC plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely.

HNP transmission line corridors pass through land that primarily is a mixture of cultivated land, grazing land, and managed timberlands (paper and pulp stock). Georgia Power Company controls vegetation in transmission corridors to keep vegetation heights low enough to prevent interference with the transmission lines. Corridors in timberlands and in the vicinity of road crossings are maintained on a 3-year cycle by mowing. The current practice may use mowers on dry ground, approved herbicides on low-lying wet areas and stream crossings where mowers cannot be operated, and hand clearing in sensitive wetland areas. In areas inaccessible to mowers, the preferred method of controlling woody plants is to apply herbicide labeled for use in wetlands, such as Accord, with a backpack sprayer. The normal practice for these corridors is to use non-restricted herbicides applied to specific woody vegetation on a three-year schedule. Some portions of the transmission corridors are cultivated by local farmers, and therefore require no additional vegetation maintenance. Private interests, who have agreed to handle vegetation maintenance, are maintaining other portions of the transmission corridors for wildlife enhancement.

Letter C-7. Attachment (page 7 of 10).

IV. SPECIES EVALUATION

A. Flatwoods Salamander

The historical range of the flatwoods salamander included parts of the States of Alabama, Florida, Georgia, and South Carolina that are in the lower Coastal Plain of the southeastern United States. There are no records of known occurrence of this species for Appling and Toombs County. Surveys of sensitive species have been conducted at the HNP site in the past; the most recent being the "Significant Species Survey" prepared by The Nature Conservancy of Georgia in 1995. An additional set of surveys covering transmission corridors and undeveloped areas of the site were conducted in 1998-1999 (TetraTech/Nus, 1999, Reference 9). The transmission corridors, because of their size, were surveyed by concentrating efforts in areas offering the greatest potential for harboring listed species (e.g. unusual communities such as sandhill seepage bogs). Resources such as aerial photographs, topographic maps, soil surveys, and National Wetlands Inventory maps were used as tools to locate these areas. The survey of the HNP site was accomplished by systematic walkover within all natural habitats. Biologists walked parallel overlapping transects through various natural habitats so that each habitat type was thoroughly searched. Similar surveys were conducted along transmission line corridors. Surveys were conducted in the spring from March 29 through April 14, 1999, and during the summer from May 24 through June 1 and on June 13, 1999. Flatwoods salamanders were not located during these surveys or the earlier "Significant Species Survey". Adults of this species are not expected to occur within the transmission corridors, but may occur in restored long-leaf pine/ wiregrass communities adjacent to suitable breeding habitat. Breeding sites consisting of shallow, ephemeral cypress or swamp tupelo ponds were not found on the HNP site adjacent to suitable adult habitat.

Georgia Power Company's goal is to re-establish the longleaf pine-wiregrass communities that were historically found in the sandhills and Coastal Plain of South Georgia. Several hundred acres of pines, including native longleaf pine, have been planted in formerly agricultural upland areas of the site. Transmission lines may be adjacent to potential breeding sites and cross areas subject to temporary flooding which may be suitable for breeding, but it is not known if suitable habitat for adults is adjacent to these locations and within the range of individuals of this species. Transmission line vegetation control normally consists of herbicide application (Accord) to specific woody vegetation using backpack sprayers. This practice is used to limit the growth of trees and other woody vegetation in the transmission corridors. This method is also used to control woody vegetation in wetland areas. Control of trees and woody vegetation supports the open canopy necessary for breeding of the flatwoods salamander. Vegetation control is conducted on a three-year cycle.

Glyphosate, the active ingredient in Accord, works on the plant, not in the soil. Studies firmly show that Accord will not bioaccumulate and proper use of this product will not result in toxicity in the flatwoods salamander.

There are no modifications proposed for license renewal; therefore no land will be disturbed in a habitat that the flatwoods salamander might be found. Current land management activities in the transmission corridors are protective of the wetland areas and foster habitats favorable to reproduction of flatwoods salamanders. Continued transmission line maintenance associated with license renewal "is not likely to adversely affect" the flatwoods salamander.

Letter C-7. Attachment (page 8 of 10) .

B. Shortnose Sturgeon

Entrainment samples at Plant Edwin I. Hatch were collected for the years 1975, 1976, and 1980. Samples were collected weekly during 1975 and 1976, and monthly in 1980. The results of these surveys are summarized in Plant Edwin I. Hatch 316(b) demonstration on the Altamaha River in Appling County, Georgia (Reference 6). Additional ichthyological drift data are available for 1974 (weekly collection) and 1979 (monthly collection), but were not used in summarizing entrainment rates. Impingement data are available for five years, including 1975, 1976, 1977, 1979, and 1980. Impingement samples include weekly samples in 1975, 1976, and 1977 and monthly samples for 1979 and 1980. Each sample represents impingement for at least a 24-hour period.

Monthly entrainment data for each taxa for 1975, 1976 represent entrainment estimates for Unit 1 operation. The 1980 data includes entrainment estimates for Unit 1 and Unit 2 operation. There was no increase in fish eggs and larvae entrainment. The differences in numbers of fish eggs and larvae are due to differences in species abundance from year to year, spawning activity upstream from the plant, river discharge, and time of year.

It was noted in the Edwin I. Hatch Nuclear Plant Annual Environmental Surveillance Report No. 3, January 1 - December 31, 1976, (Georgia Power Company, 1977) that densities of fish and fish eggs during the spawning seasons in 1975 and 1976 fluctuated directly with spawning intensity and inversely with river flow. The same conditions occurred in the 1979 and 1980 studies. Relative abundance of fish families varied during the five years of study, but the Catostomidae and Cyprinidae were the most abundant taxa each year. Clupeidae comprised only a small percentage of the total fish collected with 1980 being the highest (10.9%). The density of most fish groups was greater in night samples than in similar day samples. Shortnose sturgeon larvae where not found in any entrainment samples.

The entrainment estimates assume a uniform distribution of fish eggs and larvae, while the cross section measurements suggest that the greater densities would occur in the channel furthest from the intake (Reference 6, Figure 9). Under normal flow and pumping conditions, the intake velocity is 1.9 feet per second. The measured range of intake velocities was from 0.3 feet per second to 2.7 feet per second. Estimated percent of river flow entrained in Plant Edwin I. Hatch cooling water has remained less than one percent with the exception of the months of July, August, and September, 1980. The increase in estimated percent flow entrained during this period was due to extremely low river elevations resulting from the lack of rainfall.

Five years, 1975, 1976, 1977, 1979, and 1980, of impingement samples were also collected at Plant Edwin I. Hatch. A total of 165 fish representing 22 species were collected. The highest annual number of fish collected in impingement samples was 61 fish in 1975, while the lowest, 14 fish, was in 1980. The data indicates low impingement estimates per day and per year. The 1975 estimates are 1.2 fish per day and 438 per year; 1976 estimates are 0.4 fish per day and 146 per year; 1977 estimates are 1.1 fish per day and 401.5 per year; 1979 estimates are 1.3 fish per day and 474.5 per year; and 1980 estimates are 1.2 fish per day and 438 per year. The hogchoker, Trinectes maculatus, was the most abundant and the only species collected consistently each year. No shortnose sturgeon was collected in impingement samples.

Letter C-7. Attachment (page 9 of 10) .

Biological factors affecting impingement include the resident fish population, daily and seasonal movements to deeper water, feeding behavior, and movement associated with breeding behavior. Physical factors that affect impingement losses include river elevation, intake velocities, and intake location relative to the river cross section. Elevated river levels resulted in a reduction in intake velocities.

It is believed that shortnose sturgeon ages one year and older aggregate in the Altamaha River at or just upstream of the fresh/saltwater interface during the summer. These fish appear to move downstream into more saline water at the end of summer. During late fall and early winter, movement to less saline water occurs and some adults may move upstream toward spawning areas. Spawning is thought to occur during February through March. Some spawning fish move downstream immediately, while other remain upstream (Reference 9).

No spawning aggregation has been identified in the immediate vicinity of E. I Hatch Nuclear Plant. The main channel of the river is located near the northern bank and Plant Hatch's intake structure is located on the southern bank. Entrainment of eggs is unlikely because the shortnose sturgeon eggs are demersal, adhesive, and negatively buoyant. Entrainment of larval fish has been assessed and entrainment rates found to be low. Impingement of healthy juvenile and adult shortnose sturgeon is unlikely considering their strong swimming ability. Five years of data collected for the intake structure has not identified any entrainment or impingement of shortnose sturgeon.

There are no construction modifications of the intake structure, effluent pipes, or changes in operation proposed for the license renewal period. Existing data for impingement and entrainment (Reference 6) and the thermal plume characteristics (Reference 7) demonstrate that renewal of E. I. Hatch Nuclear Plant operating license "is not likely to adversely affect" the shortnose sturgeon.

V. REFERENCES

1. HNP Environmental Report Construction Stage, 1971.
2. HNP Environmental Report Operating License Stage, 1975.
3. Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2; Georgia Power Company; Docket Nos. 50-321 and 50-366, Atomic Energy Commission, October 1972.
4. NUREG-0147, Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 2; Georgia Power Company; Docket Nos. 50-366, Atomic Energy Commission, March 1978.
5. NPDES Discharge Monitoring Reports January 1997 – September 1998.
6. Wiltz, J. W., 1981. Plant Edwin I. Hatch 316(b) demonstration on the Altamaha River in Appling County, Georgia. Georgia Power Environmental Affairs Center, March, 1981.
7. Nichols, M. C., and S. D. Holder, 1981. Plant Edwin I Hatch Units 1 and 2 Thermal Plume Model Verification, Georgia Power Company, Environmental Affairs Center, March, 1981.
8. Rogers, S.G, and W. Weber. 1995. Movements of shortnose sturgeon in the Altamaha River system, Georgia. Contribution Series No. 57. Coastal Resources Division, Georgia Department of Natural Resources, Brunswick, Georgia. 78 pp.
9. Tetra Tech, 1999. Threatened and Endangered Species Survey: E. I. Hatch Nuclear Plant and Associated Transmission Line Corridors (1998-1999). July 9, 1999.

Letter C-7. Attachment (page 10 of 10) .

United States Department of the Interior

U.S. FISH AND WILDLIFE SERVICE
247 South Milledge Avenue
Athens, Georgia 30605

West Georgia Sub Office
P.O. Box 52560
Ft. Benning, Georgia 31995-2560

Coastal Sub Office
4270 Norwich Street
Brunswick, Georgia 31520

13 JAN 2000

C.R. Pierce
License Renewal Services Manager
Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, Alabama 35201
Attn: Mr. Jim Davis

Re: FWS Log No. 99-0887

The U.S. Fish and Wildlife Service (Service) has reviewed your letter of December 13, 1999, concerning potential impacts to threatened and endangered species associated with license renewal at the Edwin I. Hatch Nuclear Power Plant (Plant Hatch) located on the Altamaha River near the town of Baxley, Appling County, Georgia. We have also reviewed the additional information requested in our letter dated November 2, 1999. We provide the following comments in accordance with Section 7(a)(2) of the Endangered Species Act of 1973, as amended, (16 U.S.C. 1531 et seq.).

Based on the information provided, and in coordination with the Georgia Department of Natural Resources, we concur that the relicensing of Plant Hatch would not adversely affect federally threatened or endangered species under purview of the U.S. Fish and Wildlife Service. Consultation under Section 7 (a)(2) of the Endangered Species Act must be re-initiated if any of the following incidents occur: (1) new information reveals impacts of this identified action that may affect listed species in a manner not previously considered; (2) this action is subsequently modified in a manner that was not considered in this assessment; or (3) a new species is listed or critical habitat determined that may be affected by the identified action. As you proceed with consultation on the federally endangered shortnose sturgeon with the National Marine Fisheries Service, we ask that you copy our office so that we may maintain a complete administrative record for the relicensing of Plant Hatch.

We appreciate the opportunity to be involved in early planning stages of the license renewal process for the Edwin I. Hatch Nuclear Power Plant. If you should have any questions or require additional information, please contact Mr. Mark D. Bowers of my staff at (912) 986-3066.

Sincerely,

Sandra S. Tucker

Sandra S. Tucker
Field Supervisor

Letter C-8. USFWS Letter, January 13, 2000 (page 1 of 2).

cc:
Keith Parsons, GADNR-EPD, Atlanta, GA
Russ England, GADNR-WRD, Social Circle, GA
Prescott Brownell, NMFS, Charleston, SC

Letter C-8. USFWS Letter, January 13, 2000 (page 2 of 2) .

Lonice C. Barrett, Commissioner
David Waller, Director

Georgia Department of Natural Resources
Wildlife Resources Division

2070 U.S. Highway 278, S.E., Social Circle, Georgia 30025
(770) 918-6400

October 13, 1999

Mr. C.R. Pierce
License Renewal Services Manager
Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, Alabama 35201-1295

Dear Mr. Pierce:

Thank you for your letter of 15 September requesting comments on the rare species surveys conducted as part of an environmental assessment for the proposed license renewal for E.I. Hatch Nuclear Power Plant near Baxley, Georgia. My staff has reviewed the freshwater mussel survey report developed by Law Engineering and Environmental Services, Inc., as well as the terrestrial species survey report submitted by Tetra Tech, Inc. Based on this review, we find the surveys to be adequate for the purpose of assessing potential effects of the license renewal on state-listed and federally-listed species. We concur with your determination that license renewal is not likely to have an adverse impact on threatened and endangered species in the vicinity of the nuclear plant or its transmission corridors.

We appreciate the commitment of Georgia Power Company to protect and enhance rare species habitats within the boundaries of its power plant properties and transmission corridors. In particular, we applaud the stated management goal of restoring and enhancing longleaf pine-wiregrass habitats on the Hatch Nuclear Power Plant property, as well as maintaining species-rich seeps and other wetlands within the powerline corrdors. Once again, thank you for the opportunity to review these rare species survey reports and comment on this project.

Sincerely,

David Waller

David J. Waller

DW/jpa

cc: Jon Ambrose
Mike Harris

Letter C-9. GADNR Wildlife Resource Division Letter, October 13, 1999 (page 1 of 1) .

5131 Maner Road
Smyrna, Georgia 30080

Tel 404.799.2100
Fax 404.799.2141

GEORGIA POWER
A SOUTHERN COMPANY

October 18, 1999

Mr. David Bernhart
National Marine Fisheries Service
9721 Executive Center Drive North
St. Petersburg, Florida 33702

Dear Mr. Bernhart:

Enclosed are copies of additional information requested by Jim Davis for your review. This information is provided as part of the informal consultation for license renewal of E. I. Hatch Nuclear Plant and includes:

> Sections 2 and 5 of the Environmental Statement related to operation of E. I Hatch Nuclear Plant Unit 2 (March 1978).
>
> Plant Edwin I. Hatch 316(b) demonstration on the Altamaha River in Appling County, Georgia (March 1981).

Sections 2 and 5 of the Environmental Statement provide details of the plant site and the environmental assessment conducted by the NRC. The Plant Edwin I. Hatch 316(b) presents five years of entrainment and impingement data collected for this facility.

Please let me know if you need any additional information or have any questions regarding these reports.

Sincerely,

M C Nichols

M. C. Nichols
Environmental Laboratory Manager

cc:

> ✓J. T. Davis, Southern Nuclear
> C. R. Pierce, Southern Nuclear
> C. M. Hobson, Georgia Power

Letter C-10. National Marine Fisheries Letter (page 1 of 1) .

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Southeast Regional Office
9721 Executive Center Drive North
St. Petersburg, Florida 33702
(727)570-5312, FAX 570-5517

OCT - 8 1999

F/SER3:DMB

Mr. C. R. Pierce
License Renewal Services Manager
Southern Nuclear Operating Company
P.O. Box 1295
Birmingham, Alabama 35201-1295

Dear Mr. Pierce:

This is in response to your September 15, 1999 letter regarding your application to the Nuclear Regulatory Commission (NRC) to extend the current operating licenses for the Edwin I. Hatch Nuclear Power Plant for an additional twenty years. The plant's Unit 1 began operations in 1974, and Unit 2 began operations in 1979. The proposed application would extend the Units' operations to 2034 and 2038. The Plant is sited in Appling County, Georgia on the south bank of the Altamaha River. The plant has cooling water intake and discharge from and into the river.

The Federally endangered shortnose sturgeon (*Acipenser brevirostrum*) inhabits the Altamaha River and would likely use the areas in the vicinity of the plant during its spawning migration and juvenile development. Little recent data is available on the shortnose sturgeon's status and habitats in the Altamaha; however, population estimates based on tag-recapture work estimated the population at 2,862 in 1988, 798 in 1990, and 468 in 1993. There is concern that the shortnose sturgeon populations in the three major rivers to the south -- the Satilla, St. Mary's, and St. John's -- may have been recently extirpated, as the result of declining water quality. Any adverse effects on shortnose sturgeon through entrainment or impingement at the plant or through decreased water quality could have potentially serious impacts on the Altamaha population and the species as a whole.

Based on the information provided in your letter and the status of the Altamaha River population of shortnose sturgeon, we cannot concur with your determination that Plant operations through 2038 would have no effect on endangered species under National Marine Fisheries Service purview. We recommend that Southern Nuclear and the NRC prepare a more thorough biological assessment of potential effects of plant operation on shortnose sturgeon as required by section 7 of the Endangered Species Act, using the best available data. We appreciate your early notification to us on this issue, and we look forward to working with you and the NRC to ensure that plant operations do not adversely affect listed species.

Letter C-11. NMFS Letter, October 8, 1999 (page 1 of 2) .

If you have any questions, please contact David Bernhart, Fishery Biologist, at (727)570-5312.

Sincerely yours,

Charles A. Oravetz

for William T. Hogarth
Regional Administrator

cc: NRC - Leigh
F/PR3
F/SER45 - Rackley

Letter C-11. NMFS Letter, October 8, 1999 (page 2 of 2) .

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

February 2, 2000 LRS-00-001

National Marine Fisheries Service
Southeast Regional Office
9721 Executive Center Drive North
St. Petersburg, Florida 33702

Attn: Mr. Charles Oravetz, Chief, Protected Species Branch

Re: Request for Concurrence Regarding License Renewal Activity.

Southern Nuclear Operating Company (SNC) is preparing an application to renew the Edwin I. Hatch Nuclear Plant operating licenses in accordance with Nuclear Regulatory Commission (NRC) regulations. As part of this process, the NRC requires applicants to identify adverse impacts to threatened and endangered species resulting from the continued operation of the facility.

By letters dated September 15, 1999 and October 18, 1999, respectively, SNC provided National Marine Fisheries Service (NMFS) with reports and other pertinent information assessing the potential impacts of license renewal on threatened and endangered species for review. The information concluded that license renewal would have no significant effect on listed or proposed endangered or threatened species and that formal consultation under Section 7 of the Endangered Species Act was not necessary. NMFS responded by letter dated October 8, 1999, that NMFS could not concur based on the information provided by SNC and recommended a more thorough biological assessment of the potential effects of plant operations on shortnose sturgeon.

SNC met with Mr. David Bernhart of your staff on December 20, 1999, in order to clarify the scope of information necessary to complete the assessment recommended in the October 8, 1999 letter and any other pertinent information that would support the NMFS review. The goal of this meeting was to develop a thorough understanding of the information necessary for NMFS to complete an assessment of the potential impacts to the shortnose sturgeon associated with license renewal.

Letter C-12. SNC Letter to NMFS, February 2, 2000 (page 1 of 73)

LRS-00-001
Page 2 of 3

Based on discussions with Mr. Bernhart during the December 20, 1999, meeting, NMFS recommended that specific additional information be evaluated relative to the relicensing of Plant Hatch including:

- Clarification of referenced larval sturgeon data
- Additional comparative data for impingement of shortnose sturgeon
- Early life history of shortnose sturgeon as it applies to potential effects

Additional information has been developed as requested, including the items identified above, and is attached for your review. The information in the following attachment (Biological Information Update – NMFS) includes a description of the plant operations, a brief description of shortnose sturgeon life history, existing monitoring data, an evaluation of the potential for HNP operations to impact shortnose sturgeon, and a comparison to data collected from facilities on the Hudson River.

SNC has determined that continued operation of Edwin I. Hatch Nuclear Plant is "not likely to adversely affect" the shortnose sturgeon for the following reasons.

- No spawning aggregation has been located in the immediate vicinity of E. I. Hatch Nuclear Plant based on studies of the Altamaha River population.
- Data collected for the intake structure over a significant period of time did not identified any entrainment of larval shortnose sturgeon.
- Impingement of healthy juvenile and adult shortnose sturgeon is unlikely considering their strong swimming ability and the design of the intake structure. Data collected over a five-year period did not identify any impingement of shortnose sturgeon.

SNC requests, that NMFS provide a concurrence letter upon the completion of your review of this additional material. We appreciate your efforts in helping us develop the information necessary to analyze threatened and endangered species issues associated with Plant Hatch license renewal.

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by February 15, 2000 to enable us to meet our application preparation schedule.

Sincerely,

C R Pierce

C. R. Pierce
License Renewal Services Manager

CRP/JTD
Attachments

Letter C-12. SNC Letter to NMFS, February 2, 2000 (page 2 of 73)

LRS-00-001
Page 3 of 3

CC: Sandra Tucker, USFWS – Athens
Mark Bowers, USFWS – Piedmont NWR
David Bernhart, NMFS – St. Petersburg
P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter C-12. SNC Letter to NMFS, February 2, 2000 (page 3 of 73)

Biological Information Update for NMFS
Edwin I Hatch Nuclear Plant
License Renewal

Prepared by:

J. T. Davis, Southern Nuclear

M. C. Nichols, Georgia Power

A. S. Hendricks, Georgia Power

T. C. Moorer, Southern Nuclear

January 24, 2000

Letter C-12. Attachment (page 4 of 73)

Table of Contents

Letter C-12. Attachment (page 5 of 73)

I. INTRODUCTION

The purpose of this report is to provide additional information concerning Edwin I. Hatch Nuclear Plant and to address questions raised by U. S. National Marine Fisheries Service concerning the impacts of continued operation in relation to the shortnose sturgeon (*Acipenser brevirostrum*). The report summarizes plant information and existing data and discusses the consequences of the proposed action for the shortnose sturgeon.

II. PROPOSED ACTION

The proposed action is the renewal of existing NRC operating licenses for Edwin I. Hatch Nuclear Plant Units 1 and 2, which are operated in accordance with NRC operating licenses NPF-5 and DPR-57, respectively. HNP Unit 1 began commercial operation December 31, 1975, and is currently licensed to operate through August 6, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is currently licensed to operate through June 13, 2018. NRC regulations (10 CFR Part 54) allow license renewal for periods of up to 20 years, which would extend the operation of Unit 1 through August 6, 2034, and extend the operation of Unit 2 through June 13, 2038.

III. SITE DESCRIPTION

A. General Plant Information

The Edwin I. Hatch Nuclear Plant (HNP) is a steam-electric generating facility operated by Southern Nuclear Operating Company (SNC) (Reference 1). HNP is located in Appling County, Georgia, at river kilometer (rkm) 180, slightly southeast of the U.S. Highway 1 crossing of the Altamaha River. It is approximately 11 miles north of Baxley, Georgia; 98 miles southeast of Macon, Georgia; 73 miles northwest of Brunswick, Georgia; and 67 miles southwest of Savannah, Georgia. The Universal Transverse Mercator coordinates of the Unit 2 reactor (to the nearest 100 meters) are Zone 17R LF 3,533,700 meters North and 372,900 meters East. These coordinates correspond to latitude 31 degrees, 56 minutes, and 4 seconds North and longitude 82 degrees, 20 minutes, and 39 seconds West. Figures VI-1 and VI-2 illustrate the HNP location.

HNP is a two-unit plant. Each unit is equipped with a General Electric Nuclear Steam Supply System that utilizes a boiling-water reactor with a Mark I containment design. Both units were originally rated at 2,436 megawatt-thermal and designed for a power level corresponding to approximately 2,537 megawatt-thermal. Both units are now licensed for 2,763 megawatt-thermal (63 FR 53473-53478, October 5, 1998). HNP uses a closed-loop system for main condenser cooling that withdraws from and discharges to the Altamaha River via shoreline intake and offshore discharge structures. Descriptions of HNP can be found in documentation submitted to U.S. Nuclear Regulatory Commission (NRC) for the original operating license and subsequent license amendments. Georgia Power Company (GPC) submitted environmental reports for the construction stage and operating license stage for HNP in 1971 and 1975, respectively (References 2 and 3). In 1972, the Atomic Energy Commission (AEC)1 issued a Final Environmental Statement (FES) for Units 1 and 2 (Reference 4), and in 1978 issued a FES for Unit 2 (Reference 5). The FESs evaluate the environmental impacts from plant construction and operation in accordance with the National Environmental Policy Act (NEPA).

Letter C-12. Attachment (page 6 of 73)

[1]. Predecessor agency to NRC.

The property at the HNP site totals approximately 2,240 acres and is characterized by low, rolling sandy hills that are predominantly forested. A property plan is shown in Figure VI-3. Figure VII-4 provides a more detailed site plan. The property includes approximately 900 acres north of the Altamaha River in Toombs County and approximately 1,340 acres south of the River in Appling County. All industrial facilities associated with the site are located in Appling County. The restricted area, which comprises the reactors, containment buildings, switchyard, cooling tower area and associated facilities, is approximately 300 acres (Figure VI-4). Approximately 1,600 acres are managed for timber production and wildlife habitat.

B. Heat Dissipation System

The excess heat produced by HNP's two nuclear units is absorbed by cooling water flowing through the condensers and the service water system. Main condenser cooling is provided by mechanical draft cooling towers. Each HNP circulating water system is a closed-loop cooling system that utilizes three (Reference 3) cross-flow and one counter-flow mechanical-draft cooling towers for dissipating waste heat to the atmosphere.

For both Units 1 and 2, cooling tower makeup water is withdrawn from the Altamaha River through a single intake structure. The intake structure is located along the southern shoreline of the Altamaha River (Figure VI-3) and is positioned so that water is available to the plant at both minimum flow and probable flood conditions. The main river channel is located closer to the northern shoreline. The intake is approximately 150 feet long, 60 feet wide, and the roof is approximately 60 feet above the water surface at normal river level. The water passage entrance is about 27 feet wide and extends from 16 feet below to 33 feet above normal water levels. Large debris is removed by trash racks, while small debris is removed by vertical traveling screens with a 3/8 inch mesh. Water velocity through the intake screens is 1.9 feet per second (fps) at normal river elevations and decreases at higher river flows.

Water is returned to the Altamaha River via a submerged discharge structure that consists of two 42-inch lines extending approximately 120 feet out from the shore at an elevation of 54 feet mean sea level. The point of discharge is approximately 1,260 feet down-river from the intake structure and approximately 4 feet below the surface when the river is at its lowest level (Figure VI-3).

The National Pollutant Discharge Elimination System (NPDES) Permit for HNP (GA0004120) issued by the Environmental Protection Division (EPD) of the Georgia Department of Natural Resources (GA DNR) in 1997 requires weekly monitoring of discharge temperatures, but does not stipulate a maximum discharge temperature or maximum temperature rise across the condenser. Maximum discharge temperatures measured at the mixing box, which are reported to EPD on a quarterly basis, range from 62 °F in winter to 94 °F in summer (see Table V-1).

C. Surface Water Use

The Altamaha River is the major source of water for the plant. Water is withdrawn from the River to provide cooling for certain once-through loads and makeup water to the cooling towers. SNC is permitted (GADNR Permit 001-0690-01) to withdraw a monthly average of up to 85 million gallons per day with a maximum 24-hour rate of up to 103.6 million gallons. As a condition of this permit, SNC is required to monitor and report withdrawals. Table V-2 provides the annual average daily withdrawal and the maximum daily withdrawal for the years 1989 through 1997. As shown in Table V-2, HNP withdraws an annual average of 57.18 million gallons per day (88 cubic feet per second (cfs)).

Letter C-12. Attachment (page 7 of 73)

The evaluation of surface water use in the FES concluded that the consumptive losses would be approximately 46 percent of the total water withdrawn from the River. In NRC's environmental assessment for an extended power uprate (Volume 63 Number 192 FR pages 53473-53478, at page 53474), NRC concluded that the necessary increase in makeup water to support the higher heat load would be insignificant and that cooling tower blowdown would decrease by approximately 626 gallons per minute (1.4 cfs). As evaluated by NRC, consumptive water use for the plant operating at the extended power level is expected to be 57 percent of the total withdrawal (Reference 7).

The thermal discharge plume has been modeled using the Motz-Benedict model for horizontal jet discharges. The predictive thermal plume model was field verified during 1980 following commencement of Unit 2 operation (Reference 10). Twelve thermal plume monitoring surveys were conducted during 1980 and compared to model predictions. During each of the twelve surveys, temperatures were taken at depths of one foot, three feet, and five feet. All temperatures measurements were made from a boat moving along a pre-selected transects in the river using a temperature probe and continuous recorder. Monitoring equipment was calibrated in the laboratory before each survey and rechecked in the field before and after each survey. The average projected fully mixed excess temperature under average summer conditions (average river flow of 3000 cfs, ΔT of 4.7 °F) is 0.09 °F (Reference 3). During the 1980 field surveys, the period of lowest river flow and greatest cooling tower heat rejection (3220 cfs, and ΔT of 4.5 °F, respectively) resulted in a fully mixed excess temperature of 0.05 °F. The NRC modeled average expected thermal conditions and extreme thermal conditions under conservative assumptions in the E. I. Hatch Unit 2 Final Environmental Impact Statement. The NRC independently noted the small size of the thermal plume even under the conservative assumptions, and concluded thermal blockage in the Altamaha River from the plant discharge was not possible (Reference 5).

To control biofouling of cooling system components such as condenser tubes and cooling towers, an oxidizing biocide (typically sodium hypochlorite or sodium bromide) is injected into the system as needed to maintain a concentration of free oxidant sufficient to kill most microbial organisms and algae. When the system is being treated, blowdown is secured to prevent the discharge of residual oxidant into the river. After biocide addition, water is recirculated within the system until residual oxidant levels are below discharge limits specified in the NPDES permit (GA0004120).

Letter C-12. Attachment (page 8 of 73)

IV. STATUS REVIEW OF SHORTNOSE STURGEON

A. Life History

The shortnose sturgeon Acipenser brevirostrum is a member of the family Acipenseridae, a long-lived group of ancient anadromous and freshwater fishes. The species is currently known by at least 19 distinct population segments inhabiting Atlantic coast rivers from New Brunswick, Canada to northern Florida (Reference 15). Most shortnose sturgeon populations have their greatest abundance in the estuary of their respective river (Reference 14). The species is protected throughout its range.

The distribution of shortnose sturgeon strongly overlaps that of the Atlantic sturgeon, but life histories differ greatly between the two species. The Atlantic sturgeon is truly anadromous with adults and older juveniles spending large portions of their lives at sea. Shortnose sturgeon, however, are restricted to their natal streams. Shortnose sturgeon are not known to move among or between different river drainages (References 13 and 15).

Seasonal migration patterns and some aspects of spawning may be partially dependent on latitude. In northern rivers, shortnose sturgeon move to estuaries in summer months. In southern rivers, movement to estuaries usually occurs in winter (Reference 15). Shortnose sturgeon spawn in freshwater like the Atlantic sturgeon, but then return to the estuaries and spend much of their lives near the fresh/salt water interface. Fresh tidewaters and oligohaline areas serve as nurseries for shortnose sturgeon (Reference 11). Availability of spawning and rearing habitats may be limited throughout the range of shortnose sturgeon (Reference 14).

Shortnose sturgeon exhibit faster growth in southern rivers, but will reach larger adult size in northern rivers (Reference 15). Thus, shortnose sturgeon will reach sexual maturity (45-55 cm FL, (Reference 14)) at a younger age in southern rivers. Spawning by individual fish may only occur at intervals with frequencies of a few to several years. Dadswell et al. (Reference 16) composed a detailed summary of the known biology of shortnose sturgeon.

Rivers of the deep south are on the edge of the natural range of the shortnose sturgeon and present somewhat unique problems for the species. The majority of southern rivers and estuaries regularly reach temperatures unfavorable to shortnose sturgeon. Intolerant of saline environments and limited to riverine habitats, shortnose sturgeon must seek thermal refuges during most summers in the south. The refuges are found in lower river reaches and consist usually of a few deep holes, possibly cooled by springs or seeps. The fish concentrated in a few of these thermal refuges quickly exhaust local food supplies and appear to just be surviving the summer (Reference 11). A life history that restricts the species to individual drainages, combined with seasonally restricted use of habitats, may be directly related to the species' current endangered status. Sturgeons have long been commercially important species, which may be a leading cause in their rapid decline worldwide. For more than a century, Atlantic and shortnose sturgeon populations were subjected to extensive fishing, likely contributing to the massive population declines along the east coast (Reference 15). Prior to 1900, sturgeon catches were averaging over 3.0 million kg per annum, but this harvest was sustained for less than a decade. Prior to the closure of most east coast fisheries during the 1980s, catches had decreased to less than 1% of historical levels (References 12).

Letter C-12. Attachment (page 9 of 73)

Although the shortnose sturgeon was severely overharvested in the past, the greatest threats to survival presently include barriers to its spawning grounds created by dams, loss of habitat for other life history stages, poor water quality, and incidental capture in gill net and trawl fisheries targeting other species (Reference 13 and 16). Shortnose sturgeon was listed as endangered in 1967 by the U.S. Fish and Wildlife Service. In 1974, the National Marine Fisheries Service reconfirmed this decision under the Endangered Species Act of 1973 (Reference 13 and 15).

B. Status in Altamaha River

The Altamaha River is large, with the largest watershed east of the Mississippi River. The Altamaha River is located entirely within the state of Georgia. It flows over 800 km from its headwaters to the Atlantic Ocean. The main body of the Altamaha is formed by the confluence of the Oconee and Ocmulgee rivers in the central coastal plain at Altamaha rkm 212 (Reference 13).

The incidences of catch and overharvest of sturgeons from Georgia rivers paralleled the trends of other states. From 1888 through 1892, sturgeon catches in Georgia averaged 71,000 kg per annum (Reference 18). "As recently as 49 years ago, a dealer in Savannah (GA) was shipping 4,500 kg of carcasses per week (6,500 kg in the round) during the peak three to five weeks of the spring run"(Reference 18). Similar harvests were recorded from the Altamaha River (Reference 11).

Catch rate data for sturgeons in Georgia is just as startling. In 1880, and average seasonal catch was 100 fish per net. During a 20-year period from the late 1950s through the late 1970s, net fishermen in the lower Altamaha River caught just 1.1 to 3.2 fish per net per season (Reference 20 as presented in Reference 11). This data indicates a 97-99% decline in the sturgeon fishery (Reference 11).

There is a continuing high demand for sturgeon roe and flesh. From 1962 to 1994 the source of the majority of sturgeon catches has shifted among the Savannah, Ogeechee, and Altamaha rivers. The Altamaha River has been the focus of a "much-throttled" fishery from 1982 to present. Certain recent events have kept prices for sturgeon products high or rising, fueling commercial fisheries and some poaching (Reference 12). Some of these events were an increasing US domestic demand for all seafood products, decreased supplies of sturgeon products as fisheries closed in the US, and sturgeon stocks worldwide were becoming more depleted by overharvest and habitat degradation, particularly in the republics of the old Soviet Union (Reference 12).

The Altamaha River population of shortnose sturgeon has been the focus of much recent research to assess abundance and distribution, determine migration patterns, and describe habitat utilization. Some authors suggested the Altamaha River population of shortnose sturgeon was in better shape than the population in the Savannah River, Georgia-South Carolina (Reference 12). Another study indicated shortnose sturgeon in the Altamaha River may be experiencing lower juvenile mortality rates than in the Ogeechee River, Georgia (Reference 14). The Shortnose Sturgeon Recovery Team indicated that the Altamaha River population was the largest and most viable population south of Cape Hatteras, North Carolina (Reference 15). Relative abundance data from one sampling station during 1986-1991 appears to demonstrate a relatively stable population with little trend in the abundance of juveniles (Reference 11).

Letter C-12. Attachment (page 10 of 73)

Telemetry studies have revealed much information about the seasonal migrations of shortnose sturgeon in the Altamaha River and the importance of certain habitats. During summer in the Altamaha River, most fish ages 1+ and older are concentrated at or just upstream of the fresh/salt water interface in physiological refugia. Cooling water temperatures in the fall spur a movement of all sizes of fish to generally more saline waters. Some adult and most large juvenile fish move back to fresh tidewater near the end of autumn to overwinter with little movement or activity. In preparation for spawning in late winter-early spring, some adults will move upstream to locations near spawning sites. The majority of adults and a few large juveniles remain in oligohaline waters near the fresh/salt water interface and may be very active (Reference 13).

Several suspected spawning sites for shortnose sturgeon have been located within the Altamaha River system. Much of the spawning activity occurs in a 70 kilometer section of the Altamaha River centered about Doctortown, Georgia. Spawning is also suspected in the lower Ocmulgee River (Ocm rkm 4-16), which is several kilometers upstream of the shoals marking the transition to the upper coastal plain (Reference 13). This reach is about 40 rkm upstream of Plant Hatch.

Suspected spawning areas in the Altamaha River system were often adjacent to river bluffs with gravel, cobble, or hard rock substrate (Reference 12). Shortnose sturgeon eggs are demersal and adhesive after fertilization, sinking quickly and adhering to sticks, stones, gravel, and rubble on the stream bottom.

Shortnose sturgeon, especially juveniles, appear severely restricted to certain habitats near the fresh/salt water interface of the lower Altamaha River. During summers when the water temperature exceeds 28 °C, the fish are further restricted to a few deep holes near the interface. Recaptures of tagged fish indicate that the fish move little and lose weight during this time, which indicates the oversummering habitat is very important, and that food resources may be quickly exhausted (Reference 11). Flournoy et al (Reference 11) proposed that shortnose sturgeon were using a few deep holes in the lower Altamaha as physiological refuges, and that these holes may constitute critical habitat. They further hypothesized that the Altamaha River population of shortnose sturgeon existed only because the physiological refugia were available.

The Shortnose Sturgeon Recovery Team has identified numerous factors that may affect the continued survival and potential recovery of the species. Some of these factors may be habitat degradation or loss from dams, bridge construction, channel dredging, and pollutant discharges, as well as mortality from cooling water intake systems, dredging, and incidental capture in other fisheries (Reference 15). Recent evidence of illegal directed take of shortnose sturgeon in South Carolina indicate that poaching may also be a significant source of mortality (Reference 14).

All of the above factors may contribute to mortality in shortnose sturgeon populations, and the significance of each may vary with latitude and individual circumstances. However, the prevailing evidence seems to indicate, at least for the Altamaha River, that the primary threats to the population are commercial harvest and limited oversummering habitat. Dahlberg and Scott (Reference 17) recognized that shortnose sturgeon were often caught in gill nets by shad fishermen in the Altamaha River. The threat of bycatch remains real as many of the individual shortnose sturgeon used in recent studies were captured or recaptured with shad fishing gear. Rogers et al (Reference 12) stated that at least one of their tagged fish released in the estuary was captured in commercial shad gear, and six of

Letter C-12. Attachment (page 11 of 73)

the 36 individuals telemetered were initially collected with shad gear. Even if the fish are recognized as protected shortnose sturgeon and returned to the river, the capture may result in abandonment of spawning activity (Reference 14).

Several authors suggested the Altamaha River population of shortnose sturgeon may be healthier than the Savannah River population. In comparing the two rivers, (Reference 13) found that both rivers have discharges of similar magnitude and neither is dammed below the fall line. Both the Savannah and Altamaha are moderately industrialized, including paper mills and nuclear generating stations along their reaches from the fall line to the coast. Only the Savannah, however, is heavily altered and industrialized in its estuarine zone (Reference 12).

Previous research has shown shortnose sturgeon ages one year and older aggregate in the Altamaha River at or just upstream of the fresh/saltwater interface during the summer. These fish appear to move downstream into more saline water at the end of summer. During late fall and early winter, movement to less saline water occurs and some adults may move upstream toward spawning areas. Spawning is thought to occur during February through March. Some spawning fish move downstream immediately, while other remain upstream (Reference 13).

C. Low Potential for Plant Hatch to effect Shortnose Sturgeon

Biological, hydraulic, and physical factors affect the rates of impingement and entrainment. Southern Nuclear believes the shortnose sturgeon's known behavior and use of the Altamaha River indicates a low potential for impingement or entrainment with the cooling water for Plant Hatch. Southern Nuclear also believes the low potential for impingement or entrainment is further reduced by siting, design, and operational characteristics of Plant Hatch. This section presents information specific to this argument.

Available literature suggests there is little opportunity for shortnose sturgeon eggs or larvae to encounter the cooling water intakes at Plant Hatch. Much of the available spawning habitat for shortnose sturgeon in the Altamaha River is well downstream of Plant Hatch. Eggs and larvae from these spawning locations are not available for entrainment by Plant Hatch.

There is a suspected spawning area in the lower Ocmulgee River about 40 rkm upstream from Plant Hatch, but entrainment of eggs or larvae of from this site is also unlikely. Fertilized shortnose sturgeon eggs sink quickly and adhere tightly to rough substrates, even under high flow conditions. Shortnose sturgeon larvae seek bottom cover quickly upon hatching and seldom stray from cover (Reference 21). The larvae grow quickly and are able to maintain bottom contact without being swept downstream (Reference 21), and may linger near the spawning area for the first year of life (Reference 15). Some authors, after attempting to capture shortnose sturgeon larvae, speculated the larvae of shortnose sturgeon, contrary to larvae of Atlantic sturgeon, do not spend much time in the drift (References 22 and 23). These early life history behaviors suggest a very low potential for entrainment effects at Plant Hatch.

The location of the cooling water intake at Plant Hatch should further reduce the potential for entrainment and impingement. The intake structure was constructed flush with the shallow, southern shoreline of the Altamaha River. The deep river channel hugs the northern bank opposite of the intake structure. Literature indicates that shortnose sturgeon

Letter C-12. Attachment (page 12 of 73)

migrate along the bottom of river channels, often seeking the deepest water available. This behavior and the cooling water intake location on the shoreline opposite the river channel should minimize the probability of shortnose sturgeon encountering the intake structure.

Entrainment and impingement effects are also a function of withdrawal rates, which are reduced for facilities with closed cycle cooling systems in comparison to once through cooling systems. Plant Hatch is operated using 3 mechanical draft cooling towers per unit as described in section III B. Cooling towers have been suggested as mitigative measures to reduce known or predicted entrainment and impingement losses (see, for example, Reference 25). EPA has endorsed closed cycle cooling towers as the "best available technology" for minimizing entrainment and impingement mortality (Reference 26). The relatively small volumes of makeup and blowdown water needed for closed-cycle cooling systems result in concomitantly low entrainment, impingement, and discharge effects. Studies of intake and discharge effects of closed-cycle cooling systems have generally judged the impacts to be insignificant (Reference 9).

D. Existing Monitoring Data for Plant Hatch

This section briefly describes the methods and results of previous studies conducted at Plant Hatch. Initial preoperational surveys were conducted at Plant Hatch as required by the Unit 1 and 2 Final Environmental Statement (Reference 4) to "perform preoperational measurements of aquatic species to establish base-line data". During these surveys, one adult shortnose sturgeon was collected by gill net on March 13, 1974, in the vicinity of Plant Hatch. Three additional specimens of Acipenser sp., two juveniles and one larva were collected but could not be identified to species (Reference 5). No adult, juvenile, or larval shortnose sturgeon were collected during subsequent impingement and entrainment sampling conducted following startup of either Unit 1 or Unit 2.

Preoperational drift surveys where conducted weekly from February through May in 1973, and every 6 weeks June through December 1973. Samples were collected at four quadrates for transect above and below the plant intake and two locations close to the plant intake. Typical sample sets consisted of 14 individual samples from 15-minute collections. Drifting organisms were collected with a one-meter diameter 000-mesh nylon plankton net, set 6-12 inches above the river bottom. Samples were washed into a quart container and preserved with formalin.

Cataostomids, cyprindis, and centrarchids were the dominant ichthyoplanton families collected. Commercially important fish in these collections included Alosa sapidissima eggs, with mean densities approaching 0.3 per 1000 m3 in March. Alosa sapidissima larvae were present in drift samples from May through June, with the density never exceeding 0.03 individuals per 1000 m3. A sturgeon larva was collected during this sampling and sent to Dr. Donald Scott for identification of species, but could not be identified beyond the genus Acipenser. This is the only record of larval sturgeon found in the vicinity of Plant Hatch.

Entrainment samples at Plant Edwin I. Hatch were collected for the years 1975, 1976, and 1980 following unit startup. Samples were collected weekly during 1975 and 1976, and monthly in 1980. The results of these surveys are summarized in Reference 8, included as Appendix A in this document. Additional ichthyological drift data are available for 1974 (weekly collection) and 1979 (monthly collection), but were not used in summarizing entrainment rates. Monthly entrainment data for each taxa for 1975, 1976 represent

Letter C-12. Attachment (page 13 of 73)

entrainment estimates for Unit 1 operation. The 1980 data includes entrainment estimates for Unit 1 and Unit 2 operation. There was no increase in fish eggs and larvae entrainment. The differences in numbers of fish eggs and larvae are due to differences in species abundance from year to year, spawning activity upstream from the plant, river discharge, and time of year. No sturgeon larvae were found in any entrainment samples collected during operational monitoring.

The entrainment estimates assume a uniform distribution of fish eggs and larvae, while the cross section measurements suggest that the greater densities would occur in the channel furthest from the intake (See Appendix A, Figure 9). Under normal flow and pumping conditions, the intake velocity is 1.9 fps. The measured range of intake velocities was from 0.3 fps to 2.7 fps. Estimated percent of river flow entrained in Plant Edwin I. Hatch cooling water has remained less than one percent with the exception of the months of July, August, and September, 1980. The increase in estimated percent flow entrained during this period was due to extremely low river elevations resulting from the lack of rainfall.

Impingement data are available for five years, including 1975, 1976, 1977, 1979, and 1980. Impingement samples include weekly samples in 1975, 1976, and 1977 and monthly samples for 1979 and 1980. Each sample represents impingement for at least a 24-hour period. A total of 165 fish representing 22 species were collected. The highest number impinged per year, 61 fish, was in 1975, while the lowest, 14 fish, was in 1980. The data indicates low impingement estimates per day and per year. The 1975 estimates are 1.2 fish per day and 438 per year; 1976 estimates are 0.4 fish per day and 146 per year; 1977 estimates are 1.1 fish per day and 401.5 per year; 1979 estimates are 1.3 fish per day and 474.5 per year; and 1980 estimates are 1.2 fish per day and 438 per year. The hogchoker, Trinectes maculatus, was the most abundant and the only species collected consistently each year. Most species were collected only once during the five years. No sturgeon were collected in impingement samples during five years of sampling. In addition, no adult sturgeon has been reported impinged by the intake structure during the operation of the plant.

E. Comparison with other power generation facilities

For general comparison, the Hudson River, New York supports a large sturgeon population including both shortnose and Atlantic species. There are six fossil-fueled and one nuclear electricity generating plants located along the Hudson River, and much research has been conducted to address impingement and entrainment concerns. Results for entrainment and impingement at the power generation facilities Bowline, Indian Point, and Roseton are recently summarized for the period from 1972 through 1998 (Reference 23). These three facilities withdraw 62% of the maximum permitted water withdrawal from this reach of the Hudson River. Bowline Units 1 and 2 are two fossil fuel steam electric plants with combined capacity of 1200 MWe and utilize an intake structure located on an embayment off of the Hudson River. The maximum pumping rate is 384,000 gpm. Indian Point Units 2 and 3 are separate pressurized water reactors with combined capacity of 2042 MWe utilizing two separate shoreline intake structures. Predicted condenser cooling water flow rates are 840,000 gpm and 870,000 gpm for Indian Point Units 2 and 3, respectively. Roseton is a two-unit fossil-fueled steam electric plant with combined capacity of 1248 MWe and utilizes a shoreline intake structure. Maximum pumping rate is 641,000 gpm. Unlike Plant Hatch, all three of these facilities use once-through cooling. For comparison, the maximum pumping rate for Plant Hatch is 72,000 gpm. The USNRC notes that "Water withdrawal from adjacent bodies of water for plants with closed-cycle cooling systems is 5

Letter C-12. Attachment (page 14 of 73)

to 10 percent of that for plants with once-through cooling systems, with much of this water being used for makeup of water by evaporation."(Reference 9). The operation of the Plant Hatch cooling system is consistent with this description.

One of the environmental impacts identified for these three facilities on the Hudson River is entrainment and impingement of aquatic organisms, including striped bass, white perch, Atlantic tomcod, American shad, bay anchovy, alewife, blueback herring, and spottail shiner. Other species were considered, including Atlantic sturgeon (Acipenser oxyrhynchus) and shortnose sturgeon. No shortnose sturgeon eggs or larvae were collected in entrainment samples for these facilities over periods ranging from 5 to 14 years. As a result, entrainment effects on shortnose sturgeon are believed to be negligible.

Adult shortnose sturgeon, however, were collected in impingement samples at these facilities. Indian Point Unit 2 reported shortnose sturgeon in impingement samples for 10 of 19 years reported (ranging from 1 to 6 individuals per year). Indian Point Unit 3 reported shortnose sturgeon in impingement samples for 7 of 15 years reported (ranging from 1 to 3 individuals per year). The size of impinged shortnose sturgeon ranged from 12 to 18 inches. The low rate of impingement and the return of impinged fish to the Hudson River alive lead to the conclusion that impingement effects were negligible (Reference 23). Even though sampling has documented large numbers of affected fish at intakes along the Hudson River, and a large resident population of sturgeon exists, shortnose sturgeon are a very small component of the impingement and entrainment numbers (Reference 23). In fact, some recent research suggests that the shortnose sturgeon population in the Hudson River has increased during the last ten years and is now more numerous than the commercially exploited Atlantic sturgeon (Reference 24).

The use of closed cycle cooling minimizes water withdrawals from the Altamaha River. As a result, SNC believes that the probability is much lower of impinging shortnose sturgeon, particularly when compared to similarly situated facilities using once-through cooling systems. In addition, the existing monitoring data supports the finding that no impacts are known to occur to shortnose sturgeon from entrainment and impingement at Plant Hatch.

F. Consequences of Proposed Action

There are no construction modifications of the intake structure, effluent pipes, or changes in operation proposed for the license renewal period for Plant Hatch. Based on the life history characteristics of shortnose sturgeon, siting and operational characteristics of the plant, existing data for impingement and entrainment, and the known thermal plume characteristics there are no adverse impacts to shortnose sturgeon expected from E. I. Hatch Nuclear Plant during the license renewal period.

Letter C-12. Attachment (page 15 of 73)

V. TABLES

Letter C-12. Attachment (page 16 of 73)

Table V-1. Weekly discharge temperatures, Edwin I. Hatch Nuclear Plant, 1997-1998.

Month/Year		Unit 1 Average discharge temperature (°F)	Unit 1 Maximum discharge temperature (°F)	Unit 2 Average discharge temperature (°F)	Unit 2 Maximum discharge temperature (°F)
January	1997	63.0	68.0	63.8	67.0
February	1997	68.8	71.0	66.0	68.0
March	1997	71.6	79.0	70.0	80.0
April	1997	77.5	82.0	76.0	84.0
May	1997	78.3	85.0	78.3	86.0
June	1997	82.2	86.0	83.0	86.0
July	1997	88.0	91.0	87.5	90.0
August	1997	84.3	86.0	88.0	93.0
September	1997	84.6	88.0	86.6	86.6
October	1997	76.5	84.0	77.5	77.5
November	1997	62.3	68.0	62.0	62.0
December	1997	67.6	75.0	68.4	73.0
January	1998	61.8	69.0	62.7	69.0
February	1998	67.8	77.0	67.8	77.0
March	1998	71.4	77.0	71.0	77.0
April	1998	74.5	75.0	74.5	75.0
May	1998	83.8	89.0	81.8	86.0
June	1998	87.0	91.0	87.6	91.0
July	1998	89.8	92.0	90.3	92.0
August	1998	90.0	94.0	90.4	94.0
September	1998	87.5	89.0	85.0	91.0

Source: Reference 6.

Letter C-12. Attachment (page 17 of 73)

Table V-2. HNP surface water use.

Year	Average Daily Withdrawal (MGD)[a]	Maximum Daily Withdrawal (MGD)[a]	Average Daily Loss From Evaporation (MGD)[b]
1989	55.48	70.43	31.62
1990	56.88	80.50	32.42
1991	56.94	81.40	32.46
1992	58.02	82.73	33.07
1993	58.74	85.31	33.48
1994	57.30	83.61	32.66
1995	59.29	78.23	33.80
1996	57.07	78.03	32.53
1997	54.93	75.02	31.31
Average	57.18		32.59

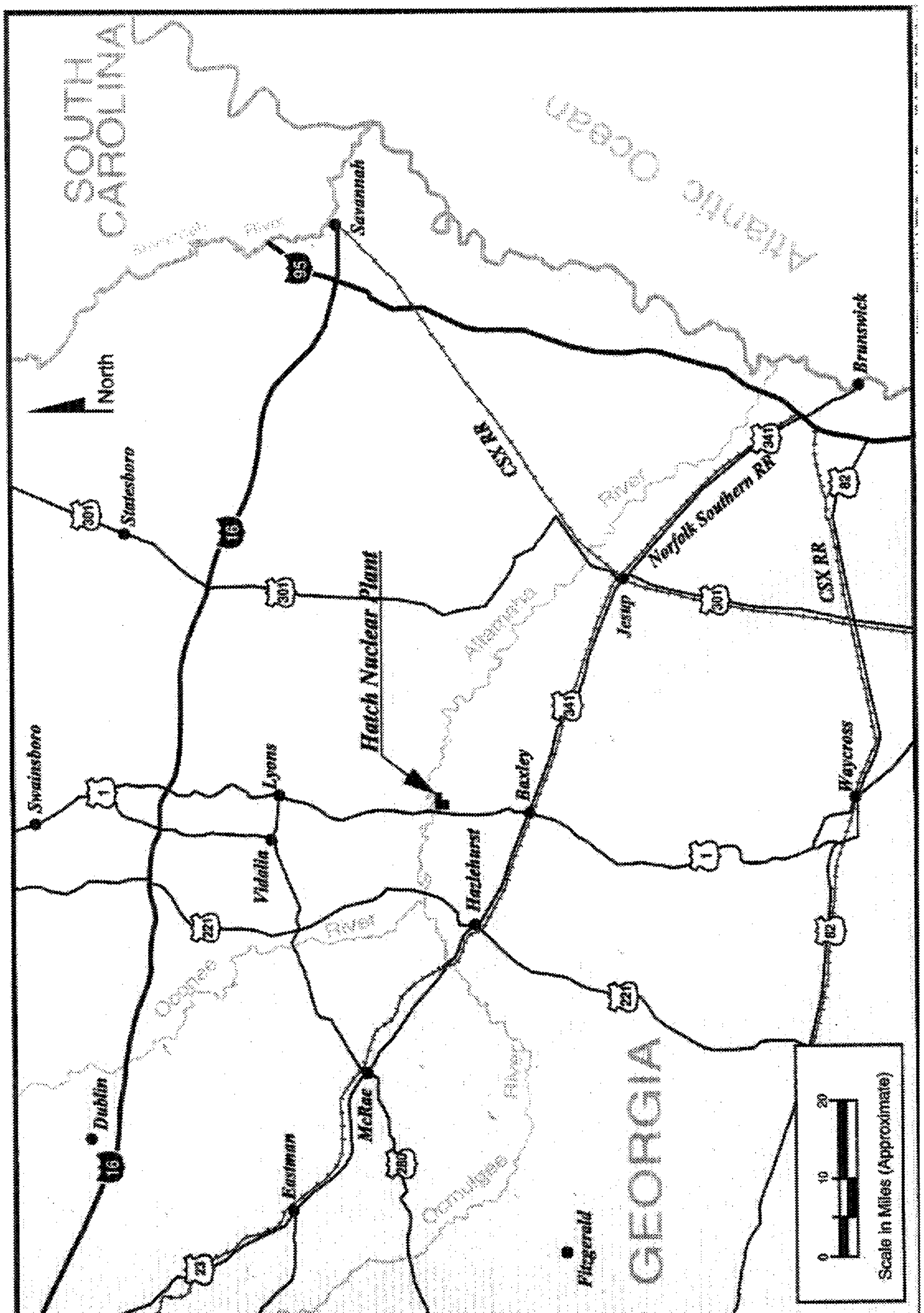
MGD = million gallons per day.

Letter C-12. Attachment (page 18 of 73)

VI. FIGURES

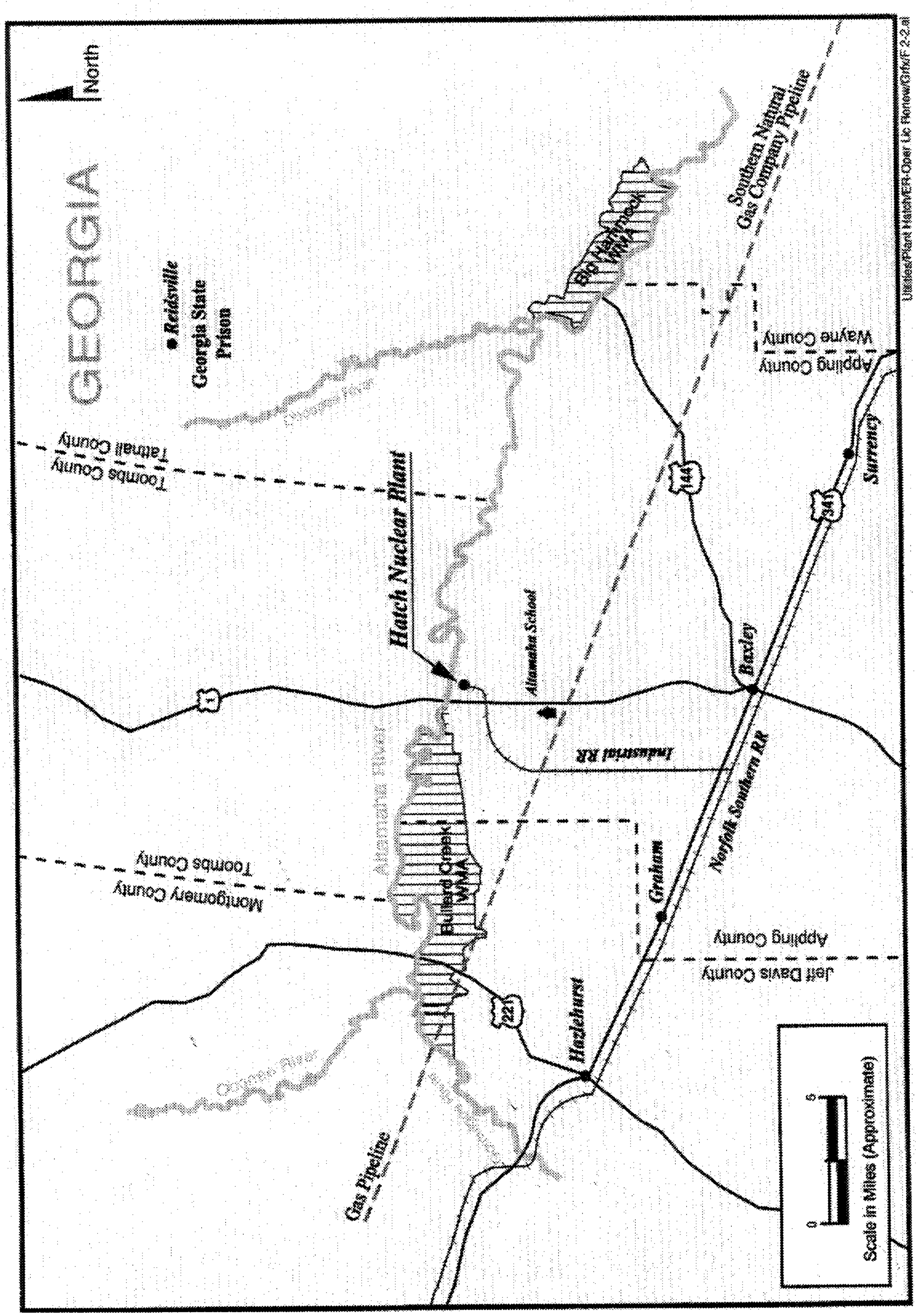
Letter C-12. Attachment (page 19 of 73)

Figure VI-1. HNP Edwin I. Hatch Nuclear Plant, 50 mile region



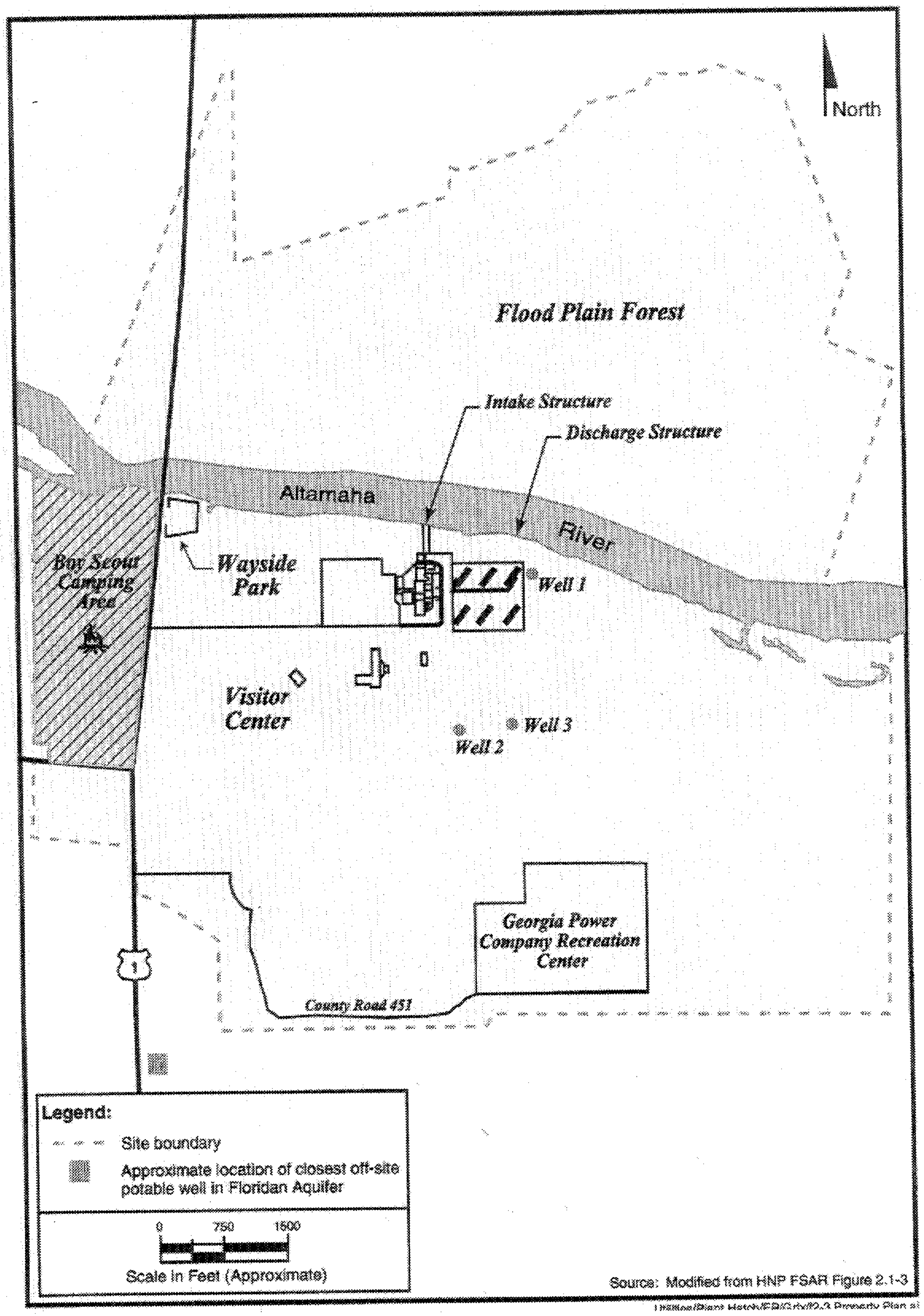
Letter C-12. Attachment (page 20 of 73)

Figure VI-2. HNP Edwin I. Hatch Nuclear Plant, 10 mile region



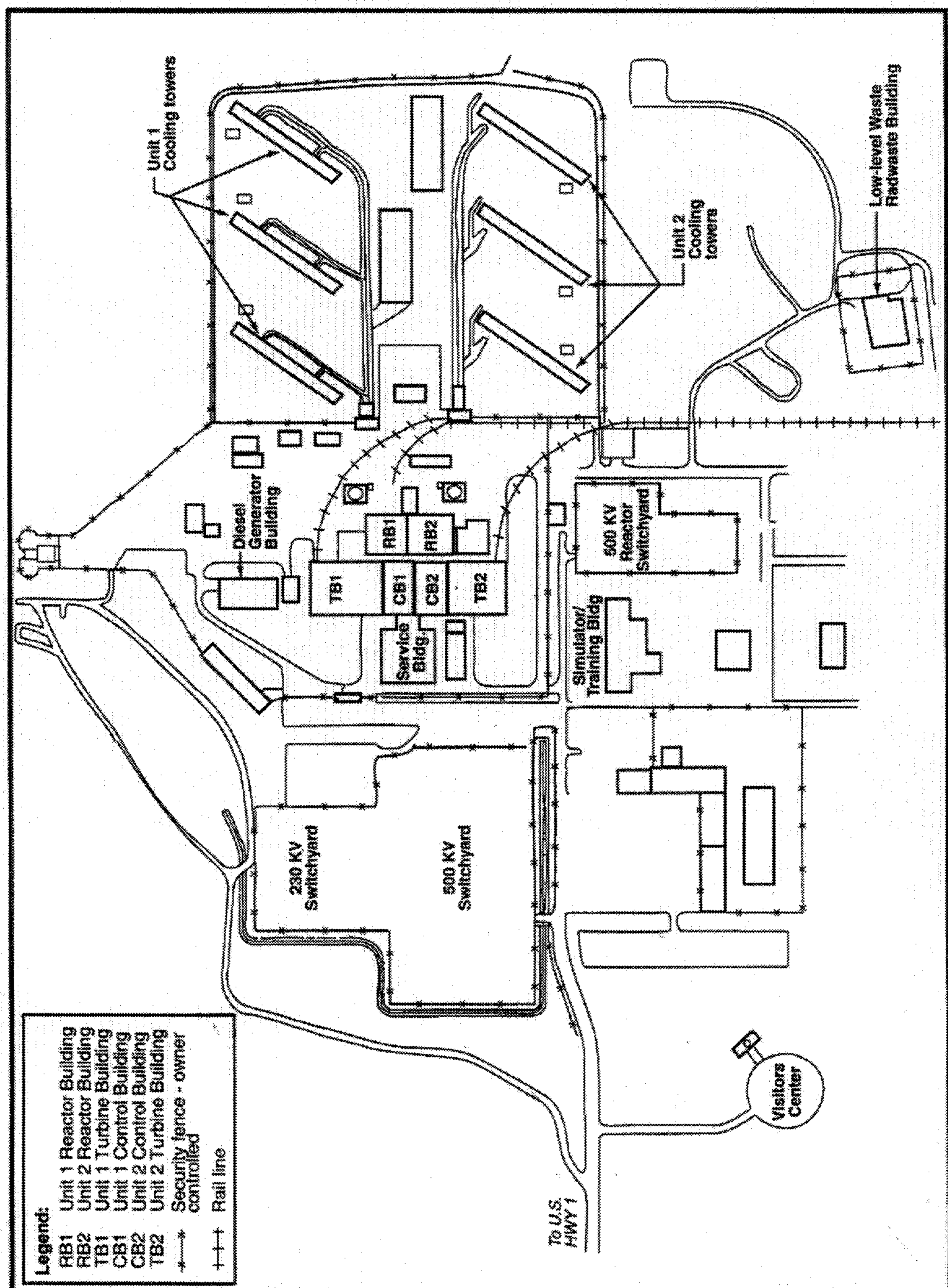
Letter C-12. Attachment (page 21 of 73)

Figure VI-3. HNP Edwin I. Hatch Nuclear Plant property plan



Letter C-12. Attachment (page 22 of 73)

Figure VI-4. HNP Edwin I. Hatch Nuclear Plant site plan



Letter C-12. Attachment (page 23 of 73)

VII. REFERENCES

1. Nuclear Operating Agreement between SNC and GPC, 1997

2. Georgia Power Company, Edwin I. Hatch Nuclear Plant Environmental Report: Construction Permit Stage, February, 1971.

3. Georgia Power Company, Edwin I. Hatch Nuclear Plant Unit No. 2 Environmental Report Operating License Stage, July 1975.

4. Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2; Georgia Power Company; Docket Nos. 50-321 and 50-366, Atomic Energy Commission, October 1972.

5. NUREG-0147, Final Environmental Statement for the Edwin I. Hatch Nuclear Plant Unit 2; Georgia Power Company; Docket Nos. 50-366, U. S. Nuclear Regulatory Commission, March 1978.

6. NPDES Discharge Monitoring Reports January 1997 – September 1998.

7. Sumner, H. L., Southern Nuclear Operating Company, Inc., letter to U.S. Nuclear Regulatory Commission Document Control Desk, dated August 8, 1997, "Edwin I, Hatch Nuclear Plant Request for License Amendment Extended Power Uprate Operation.

8. Wiltz, J. W., 1981. Plant Edwin I. Hatch 316(b) demonstration on the Altamaha River in Appling County, Georgia. Georgia Power Environmental Affairs Center, March, 1981.

9. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," U.S. Nuclear Regulatory Commission, May 1996.

10. Nichols, M. C., and S. D. Holder, 1981. Plant Edwin I Hatch Units 1 and 2 Thermal Plume Model Verification, Georgia Power Company, Environmental Affairs Center, March, 1981.

11. Flournoy, P.H., S.G. Rogers and P.S. Crawford. 1992. Restoration of shortnose sturgeon in the Altamaha River, Georgia. Final Report to the U.S. Fish and Wildlife Service Project AFS-2, Coastal Resources Division, Georgia Department of Natural Resources. 51 pp.

12. Rogers, S.G., P.H Flournoy, and W. Weber. 1994. Status and restoration of Atlantic sturgeon in Georgia. Final Report to the National Marine Fisheries Service for Anadromous Grant Number NA16FA0098-01, -02, and –03 to the Georgia Department of Natural Resources, Brunswick, GA. 121 pp.

13. Rogers, S.G., and W. Weber. 1995. Movements of shortnose sturgeon in the Altamaha River system, Georgia. Contribution Series No. 57. Coastal Resources Division, Georgia Department of Natural Resources, Brunswick, Georgia. 78 pp.

14. Weber, W. 1996. Population size and habitat use of shortnose sturgeon, Acipenser brevirostrum, in the Ogeechee River system, Georgia. Master's Thesis, University of Georgia. Athens, Georgia. 82 pp.

15. National Marine Fisheries Service. 1998. Recovery plan for the shortnose sturgeon (Acipenser brevirostrum). Prepared by the Shortnose Sturgeon Recovery Team for the National Marine Fisheries Service, Silver Spring, Maryland. 104 pp.

16. Dadswell, M.J., B.D. Taubert, T.S. Squiers, D. Marchette, and J. Buckley. 1984. Synopsis of biological data on shortnose sturgeon, Acipenser brevirostrum LeSueur 1818. NOAA Technical Report. National Marine Fisheries Service 14:1-45.

17. Dahlberg, M.D., and D.C. Scott. 1971. The freshwater fishes of Georgia. Bulletin of the Georgia Academy of Sciences 29:1-64.

Letter C-12. Attachment (page 24 of 73)

18. Smith, T.I.J. 1985. The fishery, biology, and management of Atlantic sturgeon, Acipenser oxyrhynchus, in North America. 61-72 in F.P. Binkowski and S.I. Doroshov (eds.) North American Sturgeons: Biology and Aquaculture Potential. 163 pp. DR J. W. Junk, Dordrecht, Germany.

19. Rogers, G. 1985. Georgia's Atlantic sturgeon fishery. Coastlines Georgia 8 (3): 12-14.

20. Essig, R.J. 1984. Summary of biological and fishery information important for the management of sturgeon in Georgia. Internal Report, Coastal Resources Division, Georgia Department of Natural Resources, Brunswick, GA.

21. Washburn and Gillis Associates, Ltd. 1980. Studies of the early life history of the shortnose sturgeon (Acipenser brevirostrum). Final report to the Northeast Utilities Service Company. 120pp.

22. Pottle, R. and M.J. Dadswell. 1979. Studies on larval and juvenile shortnose sturgeon (Acipenser brevirostrum). Edited by Washburn and Gillis Associates, Ltd. Report to the Northeast Utilities Service Company. 87pp.

23. Central Hudson Gas and Electric, 1999. Draft Final Environmental Impact Statement for State Pollutant Discharge Elimination System Permits for Bowline Point, Indian Point Units 2 and 3, and Roseton Steam Electric Generating Stations. Submitted to New York State Department of Environmental Conservation, December 14, 1999.

24. Bain, M, and S. Nack. 1995 Population status of shortnose sturgeon in the Hudson River, in Sturgeon Notes Issue # 3. Cornell University, New York. Cooperative Fish and Wildlife Research Unit. Sponsored by the Hudson River Foundation. (see also http://www.dnr.cornell.edu/hydro2/sturgeon/stdshor.htm).

25. Barnthouse, L. W., and W. Van Winkle, "Analysis of Impingement Impacts on Hudson River Fish Populations," *American Fisheries Society Monograph*, **4**, 182-190, 1988.

26. Barnthouse, L. W., J. Boreman, T. L. Englert, W. L. Kirk, and E. G. Horn, "Hudson River Settlement Agreement: Technical Rationale and Cost Considerations", American *Fisheries Society Monograph*, **4**, 267-273, 1988.

Letter C-12. Attachment (page 25 of 73)

VIII. APPENDIX A PLANT EDWIN I. HATCH 316(B) DEMONSTRATION ON THE ALTAMAHA RIVER IN APPLING COUNTY, GEORGIA

Letter C-12. Attachment (page 26 of 73)

PLANT EDWIN I. HATCH 316(b) DEMONSTRATION
ON THE ALTAMAHA RIVER IN APPLING COUNTY, GEORGIA

GEORGIA POWER COMPANY
ENVIRONMENTAL AFFAIRS CENTER

JOHN W. WILTZ, PRINCIPAL INVESTIGATOR

March, 1981

Letter C-12. Attachment (page 27 of 73)

ACKNOWLEDGMENTS

I wish to acknowledge the following Georgia Power Company employees: Mike C. Nichols for assistance in calculating fish and fish egg densities and James A. Gardner for proposing Part 3 Hydrodynamics in the Entrainment Results, and Randy Ott for procuring impingement samples. Gary A. Breece, Ben L. Maulsby, and Mike C. Nichols reviewed the manuscript. I also wish to acknowledge the biologists and engineers who assisted in procuring and sorting of samples.

Letter C-12. Attachment (page 28 of 73)

TABLE OF CONTENTS

Letter C-12. Attachment (page 29 of 73)

LIST OF TABLES

Letter C-12. Attachment (page 30 of 73)

LIST OF FIGURES

Letter C-12. Attachment (page 31 of 73)

LIST OF FIGURES (Con't)

Conclusions

1. Fish egg and fish densities generally fluctuated directly with spawning intensity and inversely with river flow.

2. Relative abundance of fish families varied during the five years of study, but the Catostomidae and Cyprinidae were the most abundant taxa each year.

3. The density of most fish groups was greater in night samples than in similar day samples.

4. Estimated entrainment of fish and fish eggs into the cooling water has remained less than one percent of the total population during five successive spawning periods with the exception of the months of July, August, and September, 1980. The increase in estimated percent entrained during these months was due to extremely low river elevations resulting from the lack of rainfall.

5. The percent of river discharge entrained is dependent on the number of intake pumps operating and river discharge. An increase in river discharge decreases the percent entrained.

6. An increase in entrained fish eggs and larvae is not apparent for 1980 compared to 1975 and 1976. The differences in numbers of fish eggs and larvae are due to differences in species abundance from year to year, spawning activity upstream from the plant, river discharge, and time of year.

7. Based on the five years of study, estimated entrainment at Plant Edwin I. Hatch does not constitute a significant reduction in the fish population.

8. The hogchoker, Trinectes maculatus, was the most abundant and the only species collected consistently each year in the impingement sample.

9. Because of the very low number of fish impinged for the five years of study, an accurate correlation between river elevation and the number of fish impinged cannot be made.

10. The increased velocity at the bottom of the intake structure (caused by the intake pumps) may, to some degree, explain why the majority of the fish impinged were Trinectes maculatus, a bottom dweller.

11. Low intake velocities and site location are probably the primary factors resulting in low numbers of impinged fish.

Letter C-12. Attachment (page 32 of 73)

12. The impingement data for the five years indicates that impingement losses at Plant Edwin I. Hatch are extremely low and that the plant does not create a significant environmental effect.

13. The results of this investigation fulfill the requirements set forth in NPDES Permit No. GA-0004120, Part 1-B-3.

Letter C-12. Attachment (page 33 of 73)

Introduction

As required by the National Pollution Discharge Elimination System (NPDES), Permit No. Ga. 0004120, for Plant Hatch, a 316(b) demonstration was completed by Georgia Power Company. The 316 (b) demonstration proposal was submitted to the Georgia Environmental Protection Division in June, 1977, and approved in August, 1977.

Plant Hatch, owned jointly by Oglethorpe Power Corporation (30.0%), Municipal Electric Authority of Georgia (17.7%), City of Dalton (2.2%), and Georgia Power Company (50.1%), is located approximately 17.7 kilometers (11 miles) north of Baxley in Appling County in southeast Georgia. The site is on the south bank of the Altamaha River, east of U. S. Highway 1. The site, Figures 1 and 1A, consists of approximately 908.1 hectares (2,244 acres). The area is characterized by flat-to-gently-rolling terrain.

The plant consists of two nuclear units. Unit 1 has a generating capacity of 810 megawatts, while Unit 2 has a generating capacity of 820 megawatts. Unit 1 and Unit 2 went into commercial operation on December 31, 1975, and September 5, 1979, respectively.

A cooling water flow diagram for Plant Hatch Unit 2 is presented in Figure 2. (Note: The cooling water system for Unit 1 is identical to Unit 2). Figure 2A presents the plant intake structure. Cooling water for the plant circulating water system is furnished by the Altamaha River. A single intake structure housing two service water pumps per unit are required withdrawing approximately 1.5 m3/sec (22,550 gpm) of water under normal operation. The intake structure also houses four residual heat removal service water pumps. The pumps have a combined capacity of 1.0 m3/sec (16,000 gpm) and operate when the reactor is shut down. Normally, two pumps are used when the system is operating withdrawing .52 m3/sec (8000 gpm) from the river.

The intake structure is approximately 45.7 meters (m) (150 feet) long, 18.3 m (60 feet) wide, and located 18.3 m (60 feet) above normal river level. The water passage entrance is about 8.2 m (27 feet) wide and extends 4.9 m (16 feet) below to 10.1 m (33 feet) above normal water level. Large debris is removed by trash racks, while small debris is removed by vertical traveling screens with a 9.5mm (3/8-inch mesh). Water velocity through the intake screens is 57.9 cm/sec (1.9 fps) at normal river elevations and decreases at higher river flows.

Letter C-12. Attachment (page 34 of 73)

PART I ENTRAINMENT

Materials And Methods

Two sampling stations (I1 and I2) were used to collect the diel entrainment samples. The stations were located in front of the intake structure (II) and across the river (I2) as presented in Figure 3.

The study began in February 1980, and ended in September 1980, with samples taken monthly.

Samples were collected using a Wildco No. 25 twin 0.5 m diameter plankton net with a mesh size of 760 μ. Sample duration was determined by measuring the river velocity with a General Oceanics Digital Flowmeter, Model 2030 MKII, and with a calibrated curve, a time factor was obtained allowing for the filtering of approximately 500 cubic meters of water through the net. The volume of water filtered through the net was determined with the use of a permanently fixed General Oceanics, Model 2030 R2 flowmeter in the net. Samples were preserved in a 10% formalin solution and taken to the Environmental Affairs Center in Decatur, Georgia, for identification. Physicochemical data were taken at the beginning of the day sample and at the end of the night sample. Dissolved oxygen concentration and air and water temperature were measured with a Yellow Springs Instrument Company oxygen meter, Model 57. Specific conductance was measured with a Yellow Springs Instrument Company S-C-T meter, Model 33, and pH was measured with an Orion Research Ionalyzer, Model 399A.

Densities for each fish taxa collected were calculated as follows. The total number of individuals in each taxa was divided by the volume of river water filtered during day and night sampling to obtain the densities for each sample. The estimated densities for each month were obtained by averaging the densities for all samples taken during the month. Estimates of total numbers of fish eggs and fish in the vicinity of the plant were obtained by multiplying average monthly densities by total monthly river discharge using USGS data for the Altamaha River near Baxley. The percent of river discharge entrained was calculated using total monthly discharge and the total volume of water pumped each month. The estimated number of each taxa entrained was calculated by multiplying densities by the number of individuals in the vicinity of the plant by the percent of river discharge entrained.

The hydrodynamic effects of the Hatch river intake structure upon the Altamaha River were determined at river elevations 19.7 m (64.6 ft.) and estimated for 21.5 m (70.6 ft.). Velocity profiles (at river elevation 19.7 m) were measured in seven 26 m sections of the river at 0.2, 0.6, and 0.8 of the depth in each section.

Letter C-12. Attachment (page 35 of 73)

Results

Part 1 Biological

A total of 25 fish eggs and 442 fish (includes larval juveniles and adults) were collected in the eight month study. Specimens were not collected in the February samples. Most specimens, 24 eggs and 380 fish, were collected at night.

The scientific and common names of the species collected are presented in Table 1. The family Cyprinidae (includes the cyprinids, Hybognathus nuchalis, Notropis chalybaeus, and Notropis petersoni were the most abundant with 128 fish comprising 29% of the total number of fish collected (Table 2). The next most abundant families were the Catostomidae with 101 fish (22.9%) and the Centrarchidae with 78 fish (17.6%). The least abundant family was the Soleidae with one fish (.2%). The family Clupeidae was represented by 48 fish (10.9%) of which Alosa sapidissima comprised 10.4% (46 fish). Eleven Alosa sapidissima eggs were collected (44% of the total number of eggs collected).

The mean and range (in parenthesis) of total lengths for the species and the month in which they were collected are presented in Table 3.

Monthly densities for each family for the month they were collected, the estimated number of fish eggs and fish entrained by the plant, the estimated number found in the river in the vicinity of the plant, and the estimated percent entrained are given for 1980 in Table 4. The highest estimated number of fish entrained was for the family Centrarchidae at 4920.9 individuals in June. This estimate assumes a homogenous dispersal of fish in the-water (so the actual number entrained will vary). The lowest estimates were for the family Esocidae at 61.1 individuals in April. The month of September had the highest percent entrainment of 3.52% with the months of March and April the lowest at .21%.

Part 2 Physicochemical

Air temperatures recorded during the study are presented in Figure 4. The highest temperature was for the day sample in August at 32.4 C, and the lowest was the night sample in February at 12.0 C. Water temperatures are presented in Figure 5. A high of 31.0 C was recorded for the night sample in August, and a low of 7.5 C for the night sample in February. Dissolved oxygen concentration was lowest for the night sample in February and the day sample in September with a measurement of 5.2 mg/l (Figure 6). The highest recorded was 9.1 mg/l for the day sample in February. Because of meter malfunction, air and water temperature and dissolved oxygen concentration were not taken in July. pH values are given in Figure 7. Values for pH were below 6.0 for the day and night samples in February and March and the night sample in April. The highest pH recorded was 6.7 for the June, July, and August samples. pH values are not presented for September because of meter malfunction. Specific conductance is presented in Figure 8. The highest recorded was 138 microhms/cm for the night sample in September, and the lowest was 35 microhms/cm for the night sample in March.

Part 3 Hydrodynamics

Plant Hatch river pumping data for January, 1980, through October, 1980, and the percent river entrained for each month are presented in Table 5. In addition, Table 5 presents the average monthly discharge for the Altamaha River. Percent river entrained by the plant was at or above 1.0% for the months of June through October (1.0, 1.5, 3.2, 3.5, and 2.9%, respectively). The lowest percent entrained was 0.2% occurring in March and April.

Letter C-12. Attachment (page 36 of 73)

Velocity profiles were measured in seven 26 m sections of the river and are presented in Figures 9 and 10. At elevations 19.7 m and 21.5 m, average depths of each layer were 0.5 m and 1.4 m, respectively. It should be noted that the deepest section is on the north bank. Velocities of the upper and lower layers in the section of the river nearest the Hatch intake indicated that approximately 57% of the intake flow would be drawn from the upper layer, and approximately 43% would be drawn from the lower layer. With one pump operating, a maximum of 0.54 m3/sec will be withdrawn from the Altamaha River. This represents 0.6% of the discharge at river elevation of 19.7 m. A maximum of 4.8% of the flow would be diverted with two pumps operating per unit.

Letter C-12. Attachment (page 37 of 73)

Discussion

The State of Georgia has specific criteria for water quality control concerning dissolved oxygen concentration, water temperature, and pH (Georgia Environmental Protection Division, 1974).

Dissolved oxygen concentration for warm waters is a daily average of 5.0 mg/l and no less than 4.0 mg/l. Concentrations were lowest, 5.2 mg/l, for the night survey in February and the day survey in September.

Water temperatures for the state are not to exceed 32.2 C (90.0 F). Temperatures during the study did not exceed this limit with the highest, 31.0 C, recorded for the August night survey.

The pH range for the State of Georgia is 6.0 to 8.5. Values were below 6.0 for the day survey in February and March and the night survey for February, March, and April. The lowest recorded was 5.6 for the night survey in February and the day survey in March. Since the samples were collected upstream from our discharge and no industry is located upstream in the vicinity of the plant, this should indicate a normal occurrence.

The range for specific conductance for a diverse fish fauna in freshwater is between 150 and 500 microhms/cm. (Ellis et al. 1946). The highest recorded was 138 microhms/cm for the September night survey while the lowest was 35 microhms/cm for the March night survey.

Table 5 compares the Altamaha River discharge, Plant Hatch river pumping data, and the percent of river discharge entrained by the plant for 1975, 1976, and 1980. The Plant Hatch river pumping data for 1975 and 1976 assumes a constant pumping rate at 36.5 x 106 gallons/day. The 1980 pumping data is actual pumping rates obtained from plant records. The data in Table 5 shows that the percent of river discharge entrained is dependent on the number of intake pumps operating and river discharge. An increase in river discharge decreases the percent entrained. This is best illustrated for the months of June through October, 1980, a drought year for the state of Georgia.

Entrainment samples at Plant Edwin I. Hatch were collected for the years 1974, 1975, 1976, 1979, and 1980. Samples were collected weekly from 1974 through 1976 and monthly in 1979 and 1980. Table 6 presents the percent composition of the fish egg and fish for the five-year study. The differences in total number of fish eggs and fish collected are the results of the changes in sampling frequency. For the years 1975, 1979, and 1980, the most abundant fish were in the family Cyprinidae. The family Catostomidae was the most abundant for the years 1974 and 1976. The family Esocidae was the lowest for the years 1975, 1976, and 1977. The family Soleidae (an adult) was the lowest in 1980 while in 1974, the lowest was grouped as Other taxa. This group consisted of families represented by very low numbers, such as the Atherinidae and Belonidae. The commercially important <u>Alosa sapidissima</u> was highest in 1980 and lowest in 1979. The eggs of <u>Alosa sapidissima</u> were the most abundant in 1974, 1975, and 1976. No <u>Alosa sapidissima</u> eggs were collected in 1979 while in 1980, eggs from other species were more abundant.

An interesting note in Table 6 is though the data are not comprehensive, it does indicate a fluctuation in percent composition for each family from one year to another. For some families, this is more pronounced, as in the family Catostomidae; while in the family Esocidae, the percent composition was always very low.

Letter C-12. Attachment (page 38 of 73)

Monthly entrainment data for each taxa for 1975, 1976, and 1980 are presented in Table 7. The 1975 and 1976 data represents entrainment estimates for Unit 1. The 1980 data represents entrainment estimates for Unit 1 and Unit 2. With the addition of the Unit 2 intake pumps, an increase in fish eggs and larvae entrainment is expected. This may not be the case as shown by the data. An increase in entrained fish eggs and larvae is not apparent for 1980 compared to 1975 and 1976. The differences in numbers of fish eggs and larvae are due to differences in species abundance from year to year, spawning activity upstream from the plant, river discharge, and time of year.

Letter C-12. Attachment (page 39 of 73)

Summary

It was noted in the Edwin I. Hatch Nuclear Plant Annual Environmental Surveillance Report No. 3, January 1 - December 31, 1976, (Georgia Power Company, 1977) that densities of fish and fish eggs during the spawning seasons in 1974, 1975, and 1976 generally fluctuated directly with spawning intensity and inversely with river flow. The same conditions occurred in the 1979 and 1980 studies. Relative abundance of fish families varied during the five years of study, but the Catostomidae and Cyprinidae were the most abundant taxa each year. Clupeidae comprised only a small percentage of the total fish collected with 1980 being the highest (10.9%). The density of most fish groups was greater in night samples than in similar day samples.

Estimated entrainment of fish and fish eggs into Plant Edwin I. Hatch cooling water has remained less than one percent of the total population during five successive spawning periods with the exception of the months of July, August, and September, 1980. The increase in estimated percent entrained was due to extremely low river elevations resulting from the lack of rainfall. Based on the five years of study, estimated entrainment at the plant does not constitute a significant reduction in the fish population.

Letter C-12. Attachment (page 40 of 73)

PART II IMPINGEMENT

Materials And Methods

One sampling station located in the intake structure was used to collect the impingement samples (Figure 2A).

The study began in January, 1980, and ended in December, 1980, with samples taken monthly.

Samples were collected by inserting a wire basket with a 3/8 inch mesh size into the screen backwash sluiceway (Figure 11). Each sample lasted approximately 24 hours with the exception of the April and July surveys, which lasted approximately 48 hours. Samples were preserved in a 10% formalin solution and taken to the Environmental Affairs Center in Decatur, Georgia, to be identified, enumerated, weighted, and measured.

Letter C-12. Attachment (page 41 of 73)

Results

Part 1 Biological

Fourteen fish were impinged (Table 8) representing six species and one damaged ictalurid, which could not be identified to species. The most abundant species was Trinectes maculatus with six individuals impinged. Amia calva was represented by three individuals; while the remaining taxa, Aphredoderus sayanus, Ictalurus spp., Ictalurus puntatus. Lepomis auritus, and Percina nigrofasciata were represented by one individual each. The weight (grams) and length (millimeters) of each is presented in Table 8.

Part 2 Physicochemical

Water temperatures taken at the beginning and end of each survey are presented in Figures 12 and 13. The highest temperature recorded was 30.0 0 C on July 15 and 17, 1980; while the lowest was 8.9 0 C on February 15 and 16, 1980.

River elevations are presented in Figures 14 and 15. The highest, 81.9 feet, was recorded on March 19, 1980; while the lowest, 63.7 feet, was recorded on September 16 and 17, 1980. Data for Figures 14-15 are from unpublished primary computation of gage heights and discharge for the Altamaha River for 1980 at station 02225000 located near the U.S. Highway 1 bridge. Data for November and December were not available during the writing of this report.

Letter C-12. Attachment (page 42 of 73)

Discussion

Five years, 1975, 1976, 1977, 1979, and 1980, of impingement samples were collected at Plant Edwin I. Hatch. A total of 165 fish (Table 9) representing 22 species were collected. The highest number impinged, 61 fish, was in 1975, while the lowest, 14 fish, was in 1980. The data indicates low impingement estimates per day and per year. The 1975 estimates are 1.2 fish per day and 438 per year; 1976 estimates are .4 fish per day and 146 per ear; 1977 estimates are 1.1 fish per day and 401.5 per year; 1979 estimates are 1.3 fish per day and 474.5 per year; and 1980 estimates are 1.2 fish per day and 438 per year.

The hogchoker, Trinectes maculatus, was the most abundant and the only species collected consistently each year. Most species were collected only once during the five years.

Biological factors affecting impingement are: the resident fish population, daily and seasonal movements to deeper water, feeding behavior, and movement associated with breeding behavior. Other factors which determine impingement losses are: river elevation, intake velocities, and site location. Elevated river levels resulted in a reduction in intake velocities. In addition, the velocity of water in the intake structure increases from the surface to the bottom due to the intake pumps. An accurate correlation between river elevation and the number of impinged fish for the five years cannot be made because of the very low number of fish impinged. The increase in velocity at the bottom of the intake structure may, to some degree, explain why the majority of the fish impinged were Trinectes maculatus, a bottom dweller. The intake structure is located on a straight shoreline which would not harbor many fish, especially predatory game species. Low intake velocities and site location are probably the primary factors resulting in low numbers of impinged fish.

Summary

The impingement data for the five years indicates that impingement losses at Plant Edwin I. Hatch are extremely low. The findings show that impingement does not create a significant environmental effect.

Letter C-12. Attachment (page 43 of 73)

References

Ellis, M. M., B. A. Westfall, and M. D. Ellis. 1946. Determination of water quality. U.S. Department of Interior, Fish and Wildlife Service Res., Rep. 9. 122 pp.

Georgia Environmental Protection Division. 1974. Pages 701-731 in Rules and regulations for water quality control, chapter 291-3-6, revised June, 1974. Georgia 'Department of Natural Resources, Atlanta, Georgia.

Georgia Power Company. 1974. Edwin I. Hatch Nuclear Plant - Unit No. 1, semiannual environmental surveillance report No. 1, period ending December 31, 1974. Georgia Power Company, Atlanta, Georgia.

Georgia Power Company. 1975. Edwin I. Hatch Nuclear Plant - Unit 1, annual environmental surveillance report No. 2, January 1 - December 31, 1975. Georgia Power Company, Atlanta, Georgia.

Georgia Power Company. 1976. Edwin I. Hatch Nuclear Plant, annual environmental surveillance report No. 3, January l - December 31, 1976. Georgia Power Company, Atlanta, Georgia.

Georgia Power Company. 1977. Edwin I. Hatch Nuclear Plant, annual environmental surveillance report for calendar year 1977. Georgia Power Company, Atlanta, Georgia.

Georgia Power Company. 1979. Edwin I. Hatch Nuclear Plant, annual environmental surveillance report-for calendar year 1979. Georgia Power Company, Atlanta, Georgia.

Letter C-12. Attachment (page 44 of 73)

Table 1. Scientific and common names of species of fish collected during the entrainment study.

Scientific Name	Common Name
Alosa aestivalis	Blueback herring
Alosa sapidissima	American shad
Dorosoma spp.	Shad
Clupeidae	Herring and shad
Esox spp.	Pickerel
Esox americanus	Redfin pickerel
Hybognathus nuchalis	Silvery minnow
Notropis chalybaeus	Ironcolor shiner
Notropis petersoni	Coastal shiner
Cyprinidae	Minnow
Carpiodes velifer	Highfin carpsucker
Minytrema melanops	Spotted sucker
Moxostoma anisurum.	Silver redhorse
Ictalurus brunneus	Snail bullhead
Ictalurus nebulosus	Brown bullhead
Ictalurus punctatus	Channel catfish
Noturus gyrinus	Tadpole madtom
Aphredoderus sayanus	Pirate perch
Labidesthes sicculus	Brook silverside
Strongylura marina	Atlantic needlefish
Lepomis spp.	Sunfish
Lepomis auritus	Redbreast sunfish
Micropterus salmoides	Largemouth bass
Pomoxis spp.	Crappie
Perca flavescens	Yellow Perch
Percidae	Darter
Trinectes maculatus	Hogchoker
Unknown egg	
Unknown larvae	

Letter C-12. Attachment (page 45 of 73)

Table 2. Species, number of individuals collected for each month-day and night, totals for the month, for day and night, and percent composition of each taxa and each family.

Species		Feb. Day	Feb. Night	March Day	March Night	Apr. Day	Apr. Night	May Day	May Night	June Day	June Night	July Day	July Night	Aug. Day	Aug. Night	Sept. Day	Sept. Night	Totals Day	Totals Night	% of Fish	% of Egg	% of Family
Clupeidae																						10.9
	<u>*Alosa aestivalis*</u>						1										1	0	2	0.23		
	<u>*Alosa sapidissima*</u>																					
	Egg				4	1	6											1	10		44	
	Fish				1	2	2	7	28	2	3							11	34	10.41		
	<u>*Dorosoma spp.*</u>					1												1	0	0.23		
	<u>*Clupeidae*</u>							1										1	0	0.23		
Esocidae																						1.4
	<u>*Esox spp.*</u>			2	3													2	3	1.13		
	<u>*Esox americanus*</u>						1											0	1	0.23		
Cyprinidae																						29
	<u>*Hybognathus nuchalis*</u>						1	30									1	30	7.01			
	<u>*Notropis chalybaeus*</u>					1											0	1	0.23			
	<u>*Notropis petersoni*</u>										8		2					0	10	2.26		
	Cyprinidae			4	9	1	26		9	1	22		5		4		5	6	80	19.46		
Catostomidae																						23*
	<u>*Carpiodes velifer*</u>					4			6	3	12	4	12		34		1	11	65	17.19		
	<u>*Minytrema melanops*</u>				8	14		1									8	15	5.2			
	<u>*Moxostoma anisurum*</u>						1	1									1	1	0.45			

*corrected from original report

Letter C-12. Attachment (page 46 of 73)

Table 2. (Con't)	Feb.		March		Apr.		May		June		July		Aug.		Sept.		Totals		% of	% of	% of
Species	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Fish	Egg	Family
Ictaluridae																					6.6
Ictalurus							12									0	12	2.71			
Ictalurus nebulosus								2	5		7					2	12	3.17			
Ictalurus punctatus											2					0	2	0.45			
Noturus gyrinus									1							0	1	0.23			
Aphredoderidae																					5.6
Aphredoderus sayanus				2	22		1		1							2	24	5.66			
Atherinidae																					0.7
Labidesthes sicculus									3							0	3	0.68			
Belonidae																					0.7
Strongylura marina							1	1	1							1	2	0.68			
Centrarchidae																					17.6
Lepomis spp.				1			1	1	7		1			56	1	2	66	15.38			
Lepomis auritus					1											0	1	0.23			
Micropterus salmoides									1							0	1	0.23			
Pomoxis spp.		5	3													5	3	1.81			
Percidae																					2.9
Perca flavescens		1	1	2	2	4									1	7	4	2.49			
Percidae					2											0	2	0.45			
Soleidae																					0.2
Trinectes maculatus								1								1	0	0.23			
Unknown Egg			6		2		6									2	12		56		
Unknown Fish							4				1		1				6	1.36			1.4
Totals 0	0	12	27	22	80	14	100	11	64	4	30	0	95	0	9	65	403	100		100	100

Letter C-12. Attachment (page 47 of 73)

Table 3. Mean and Range of the Total Lengths (mm) for Each Species for Each Month Sampled (Specimens Which Could Be Identified But Were Damaged Were Not Measured or Included in This Table).

Species	Feb.	March	April	May	June	July	Aug.	Sept.
Alosa aestivalis			4.9					
Alosa sapidissima		6.6	10.2 (6.2-11.8)	17.9 (7.7-25.0)	20.2 (17.0-23.0)			
Dorosoma spp.			3.5					
Clupeidae				4.6				
Esox spp.		17.2 (11.2-21.0)						
Esox americanus			45.0					
Hybognathus nuchalis				19.5 (15.0-25.0)				
Notropis chalybaeus			37.0					
Notropis petersoni					10.5 (8.8-12.9)	15.5 (15.0-16.0)		
Cyprinidae		4.7 (3.8-7.1)	8.6 (3.9-15.0)	19.3 (7.7-24.0)	5.7 (3.5-9.8)	4.8 (3.9-5.3)	5.0 (4.9-5.2)	6.6 (4.8-9.1)
Carpiodes velifer			7.5 (6.7-8.0)	6.4 (5.3-7.4)	6.6 (5.3-8.4)	5.9 (5.3-6.6)	6.4 (5.3-7.7)	7.3
Minytrema melanops			11.2 (8.7-15.0)	11.5				
Moxostoma anisurum				23.5 (21.0-26.0)				
Ictalurus brunneus				19.5 (17.0-21.0)				
Ictalurus nebulosus					19.6 (17.0-25.0)	16.1 (15.0-17.0)		

Letter C-12. Attachment (page 48 of 73)

Table 3. (Con't)

Species	Feb.	March	April	May	June	July	Aug.	Sept.
Ictalurus punctatus						24.0 (18.0-30.0)		
Noturus gyrinus					13.0			
Aphredoderus sayanus			8.1 (3.5-27.0)'	33.0				
Labidesthes sicculus					4.7 (4.2-4.9)			
Strongylura marina				17.0	15.5 (13.0-18.0)			
Lepomis spp.			5.3	7.3	9.6 (5.2-13.4)	13.0	6.9 (4.2-8'.3)	15.0
Lepomis auritus			27.0					
Micropterus salmoides					6.3			
Pomoxis spp.		4.2 (3.8-5-3)						
Perca flavescens		7.1 (6.9-7-3)	6.1 (5.6-7.0)	7.4 (6.7-8.8)				5.9
Percidae			6.2					
Trinectes maculatus					76.0			
Unknown Fish	Not measured because all these specimens were damaged.							

Letter C-12. Attachment (page 49 of 73)

Table 4. Average Monthly Densities for Each Family, the Estimated Number Found in the River in the Vicinity of the Plant, the Percent of River Discharge Entrained, and the Estimated Number Entrained for 1980.

Month	Family	Monthly Densities Per 1000 m3 of Water	Estimated Number of Eggs & Fish in the Vicinity of the Plant	Percent of River Discharge Entrained	Estimated Number of Eggs & Fish Entrained by the Plant Each Month
February	NOSP*	NOSP	NOSP	0.5	NOSP
March	Clupeidae	0.9	84,609	0.2	177
	Clupeidae egg	1.0	94,010		197
	Esocidae	0.7	65,807		138
	Cyprinidae	3.3	313,053		657
	Centrarchidae	4.1	381,680		801
	Percidae	0.6	53,116		112
	Unknown egg	1.5	140,075		294
	TOTAL	12.1	1,132,350		2,376
April	Clupeidae	1.8	173,628	0.2	365
	Clupeidae egg	2.0	192,910		405
	Esocidae	0.3	28,938		61
	Cyprinidae	7.9	762,034		1,600
	Catostomidae	7.8	752,388		1,580
	Aphredoderidae	6.6	636,636		1,337
	Centrarchidae	0.6	57,876		122
	Percidae	1.8	173,628		365
	Unknown egg	0.6	57,876		122
	TOTAL	29.4	2,835,914		5,955
May	Clupeidae	10.5	286,330	0.8	2,293
	Cyprinidae	13.0	354,516		2,836
	Catostomidae	2.6	70,903		567
	Ictaluridae	3.5	95,447		764
	Aphredoderidae	0.3	8,181		65
	Belonidae	0.3	8,181		65
	Centrarchidae	0.3	8,181		65

Letter C-12. Attachment (page 50 of 73)

Table 4. (Con't)

Month	Family	Monthly Densities Per 1000 m3 of Water	Estimated Number of Eggs & Fish in the Vicinity of the Plant	Percent of River Discharge Entrained	Estimated Number of Eggs & Fish Entrained by the Plant Each Month
May (Con't)	Percidae	1.0	27,270	0.8	218
	Unknown egg	1.7	46,356		371
	Unknown	1.1	29,998		240
	TOTAL	34.3	935,662		7,485
June	Clupeidae	1.8	45,086	1.0	437
	Cyprinidae	12.3	308,088		2,988
	Catostomidae	5.0	125,239		1,215
	Ictaluridae	1.8	45,086		437
	Aphredoderidae	0.4	10,019		97
	Atherinidae	1.3	32,562		316
	Belonidae	0.9	22,543		219
	Centrarchidae	3.8	95,182		923
	Soleidae Adult	0.5	12,524		121
	TOTAL	27.8	696,328		6,754
July	Cyprinidae	2.1	31,060	1.5	478
	Catostomidae	3.6	53,246		820
	Ictaluridae	2.1	31,060		478
	Centrarchidae	0.4	5,916		91
	Unknown	0.4	5,916		91
	TOTAL	8.6	127,198		1,959
August	Cyprinidae	11.5	85,847	3.2	2721
	Centrarchidae	20.8	155,271		4,922
	Unknown	0.3	2,240		74
	TOTAL	32.6	243,458		7,718
September	Cyprinidae	2.9	17,493	3.5	616
	Catostomidae	0.6	3,619		127
	Centrarchidae	0.6	3,619		127
	Percidae	0.6	3,619		127
	TOTAL	4.7	28,350		998

*Indicates No Species Found

Letter C-12. Attachment (page 51 of 73)

Table 5. Altamaha River Monthly Discharge, Plant Hatch River Pumping Data, and the percent river flow entrained for each month for 1975, 1976, and 1980.									
Year	1975			1976			1980		
	Altamaha River Discharge (MGD)	Plant Hatch Pumping Data (MGD)	Percent of River Discharge Entrained	Altamaha River Discharge (MGD)	Plant Hatch pumping Data (MGD)	Percent of River Discharge Entrained	Altamaha River Discharge (MGD)	Plant Hatch pumping Data (MGD)	Percent of River Discharge Entrained
Month									
January	11,800	36.5	0.3%	9,433	36.5	0.4%	6,982	50.9	0.7%
February	17,160	36.5	0.2%	10,461	36.5	0.3%	10,282	51.4	0.5%
March	30,556	36.5	0.1%	13,558	36.5	0.3%	24,761	52.7	0.2%
April	26,981	36.5	0.1%	8,450	36.5	0.4%	25,507	53.8	0.2%
May	13,331	36.5	0.3%	10,810	36.5	0.3%	7,210	57.5	0.8%
June	9,479	36.5	0.4%	9,375	36.5	0.4%	6,623	64.3	1.0%
July	7,397	36.5	0.5%	5,450	36.5	0.7%	3,908	60.2	1.5%
August	7,856	36.5	0.5%	2,688	36.5	1.4%	1,984	62.5	3.2%
September	4,797	36.5	0.8%	2,566	36.5	1.4%	1,596	56.1	3.5%
October	7,248	36.5	0.5%	4,659	36.5	0.8%	1,946	57.3	2.9%

Letter C-12. Attachment (page 52 of 73)

Table 6. Percent Composition of Fish Taxa for 1974, 1975, 1976, 1979, and 1980 Entrainment Data.

	Fish Percent Composition				
Family	1974	1975	1976	1979	1980
Aphredoderidae	2.11	2.98	1.11	--	5.89
Atherinidae	--	--	--		0.7
Belonidae	--	--	--	--	0.7
Catostomidae	61.75	12.38	56.18	17.8	22.9
Centrarchidae	5.27	21.85	14.46	23.2	17.6
Clupeidae	5.23	2.39	2.54	1.3	10.9
Cyprinidae	13.66	37.21	18.65	48.4	29
Esocidae	1.33	0.53	0.11	0.7	1.4
Ictaluridae	0.16	11.57	0.29	2.7	6.6
Percidae	6.38	4.21	4.44	6	2.9
Soleidae	--	--	--	--	0.2
Other Taxa	0.12	1.05	0.36		--
Unidentified	3.54	5.83	1.86	--	1.4
Total Fish Collected	2,562	1,712	2,793	151	442
	Eggs Percent Composition				
Alosa sapidissima	51.16	52.71	86.16	--	44
Other Taxa	48.84	47.29	13.84		56
Total Eggs Collected	258	258	1,033		25

Letter C-12. Attachment (page 53 of 73)

Table 7. Comparison of Monthly Entrainment Data for each Taxa for 1975, 1976, and 1980 for Plant Hatch

Larvae

	Clupeidae			Catostomidae			Centrarchidae		
Month	1975	1976	1980	1975	1976	1980	1975	1976	1980
February	0	7	0	0	0	0	11	0	0
March	0	88	176	1978	580	0	216	562	405
April	1	492	374	2860	6987	1582	82	362	123
May	31	47	2277	1342	1443	559	1426	346	65
June	202	0	426	140	109	1205	4153	219	932
July	*	0	0	*	589	823	*	667	80
August	*	**	0	*	**	0	*	**	4911
September	*	**	0	*	**	122	*	**	122

*Sampling was discontinued after the June survey in 1975
**Sampling was discontinued after the July survey in 1976

	Cyprinidae			Other			Total Larvae		
	1975	1976	1980	1975	1976	1980	1975	1976	1980
Month									
February	433	0	0	60	0	0	504	7	0
March	5420	128	664	1422	228	259	9036	1585	1504
April	1289	2445	1600	2775	810	1753	7022	11095	5432
May	455	346	2837	1019	248	1366	4273	2429	7104
June	258	749	2978	1206	52	1122	5959	1129	6663
July	*	185	479	*	18	159	*	1958	1541
August	*	**	2714	*	**	78	*	**	7703
September	*	**	609	*	**	122	*	**	975

Egg

	Clupeidae			Other			Total Eggs		
Month	1975	1976	1980	1975	1976	1980	1975	1976	1980
February	34	271	0	49	13	0	83	284	0
March	93	1258	199	137	228	297	230	1486	496
April	38	1518	408	201	358	122	239	1876	530
May	351	1018	0	438	66	370	789	1083	390
June	11	0	0	0	0	0	11	0	0
July	*	0	0	*	12	0		12	0
August	*	**	0	*	**	0			0
September	*	**		*	**				

*Sampling was discontinued after the June survey in 1975
**Sampling was discontinued after the July survey in 1976

Letter C-12. Attachment (page 54 of 73)

Table 8. Species and Numbers of Fish Collected in Monthly Impingement Surveys at Plant Edwin I. Hatch for 1980.

Date	Species Collected*	Length (mm)	Weight (grams)
1-15-80	NOSP**		
2-15-80	NOSP		
3-18-80	Trinectes maculatus (6)	61	5.0
		63	5.7
		65	6.0
		54	3.3
		61	4.9
		61	5.0
	Percina nigrofasciata (1)	43	.8
4-15-80	Aphredoderus sayanus (1)	816	11.3
5-10-80	Amia calva (3)	115	17.0
		107	15.5
		107	14.0
6-17-80		NOSP	
7-15-80	Ictalurus spp. (1) Specimen Damaged		
	Lepomis auritus (1)	55	2.7
8-19-80	Ictalurus punctatus (1)	203	84.3
9-16-80		NOSP	
10-14-80		NOSP	
11-12-80		NOSP	
12-17-80		NOSP	

*Number Collected in Parenthesis

**Indicates No Species Collected

Letter C-12. Attachment (page 55 of 73)

Table 9. Species and Numbers of Fish Collected in Impingement Surveys at Plant Edwin I. Hatch for 1975, 1976, 1977, 1979, and 1980.

Species	Common Name	1975	1976	1977	1979	1980	Totals
Amia calva	Bowfin			3		3	6
Alosa sapidissima	American shad			1			1
Dorosoma cepedianum	Gizzard shad	2					2
Dorosoma petenense	Threadfin shad		3				3
Esox americanus	Redfin pickerel	1					1
Hybognathus nuchalis	Silvery minnow	1		1			2
Notropis callisema.	Altamaha shiner	1					1
Notropis hudsonius	Spottail shiner			1			1
Notropis spp.	Minnow	1					1
Ictalurus brunneus	Snail bullhead			1			1
Ictalurus nebulosus	Brown bullhead	1					1
Ictalurus platycephalus	Flat bullhead.			1			1
Ictalurus punctatus	Channel catfish	1	1	1		1	4
Ictalurus spp.	Catfish						1
Aphredoderus sayanus	Pirate perch	2				1	3
Acantharchus pomotis	Mud sunfish		2	1			3
Centrarchus macropterus	Flier	3		1	1		5
Lepomis auritus	Redbreast sunfish	1	1	2		1	5
Lepomis gulosus	Warmouth			15	1		16
Lepomis macrochirus	Bluegill	4			1		5
Lepomis punctatus	Spotted sunfish			2			2
Lepomis spp.	Sunfish			1			1
Pomoxis nigromaculatus	Black crappie		1	1			2
Percina nigrofasciatus	Blackbanded darter			1	1	2	
Trinectes maculatus	Hogchoker	43	15	15	16	6	95
Totals		61	23	47	20	14	165

Letter C-12. Attachment (page 56 of 73)

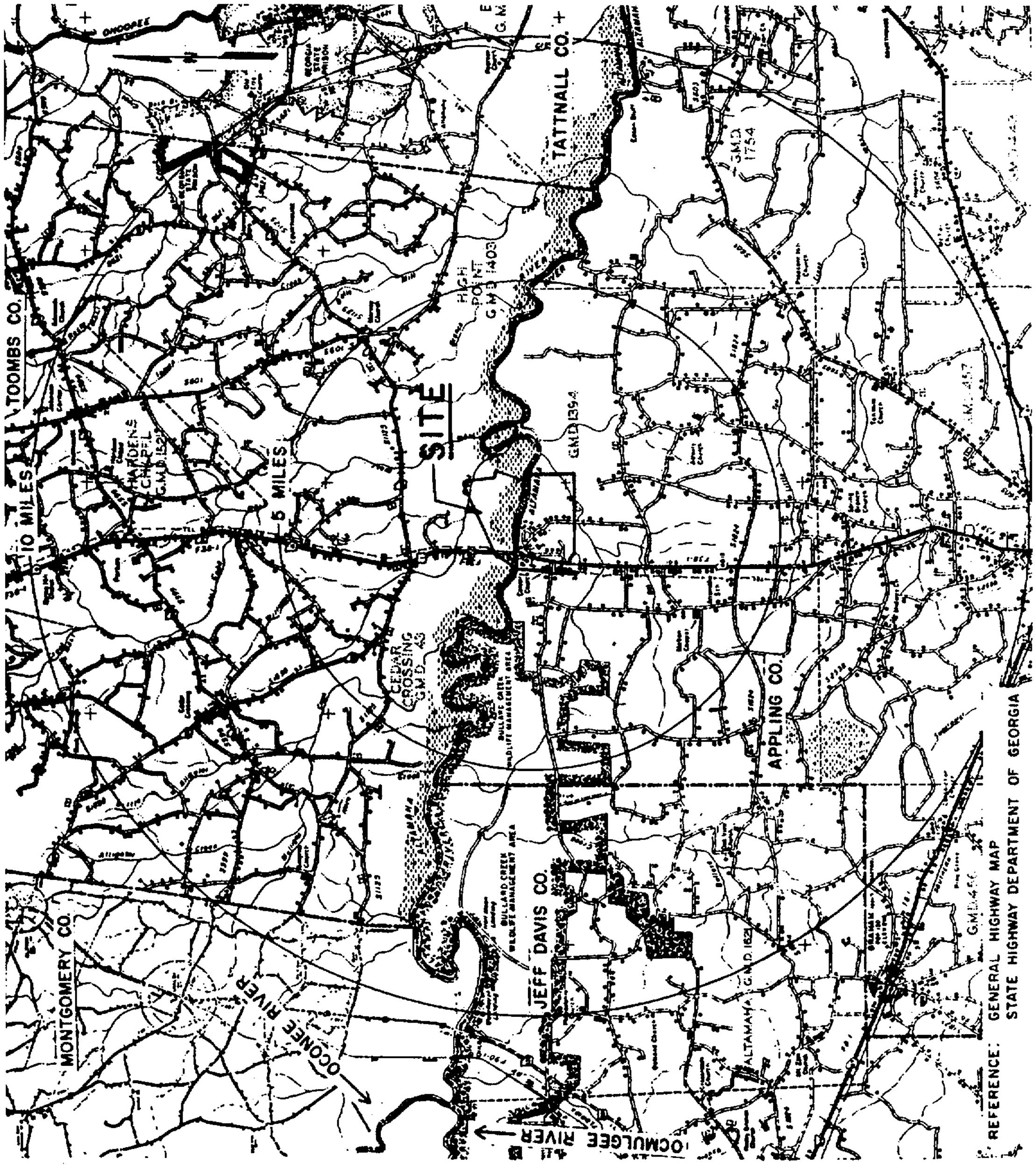


Figure 1. Plant Edwin I. Hatch Site

Letter C-12. Attachment (page 57 of 73)

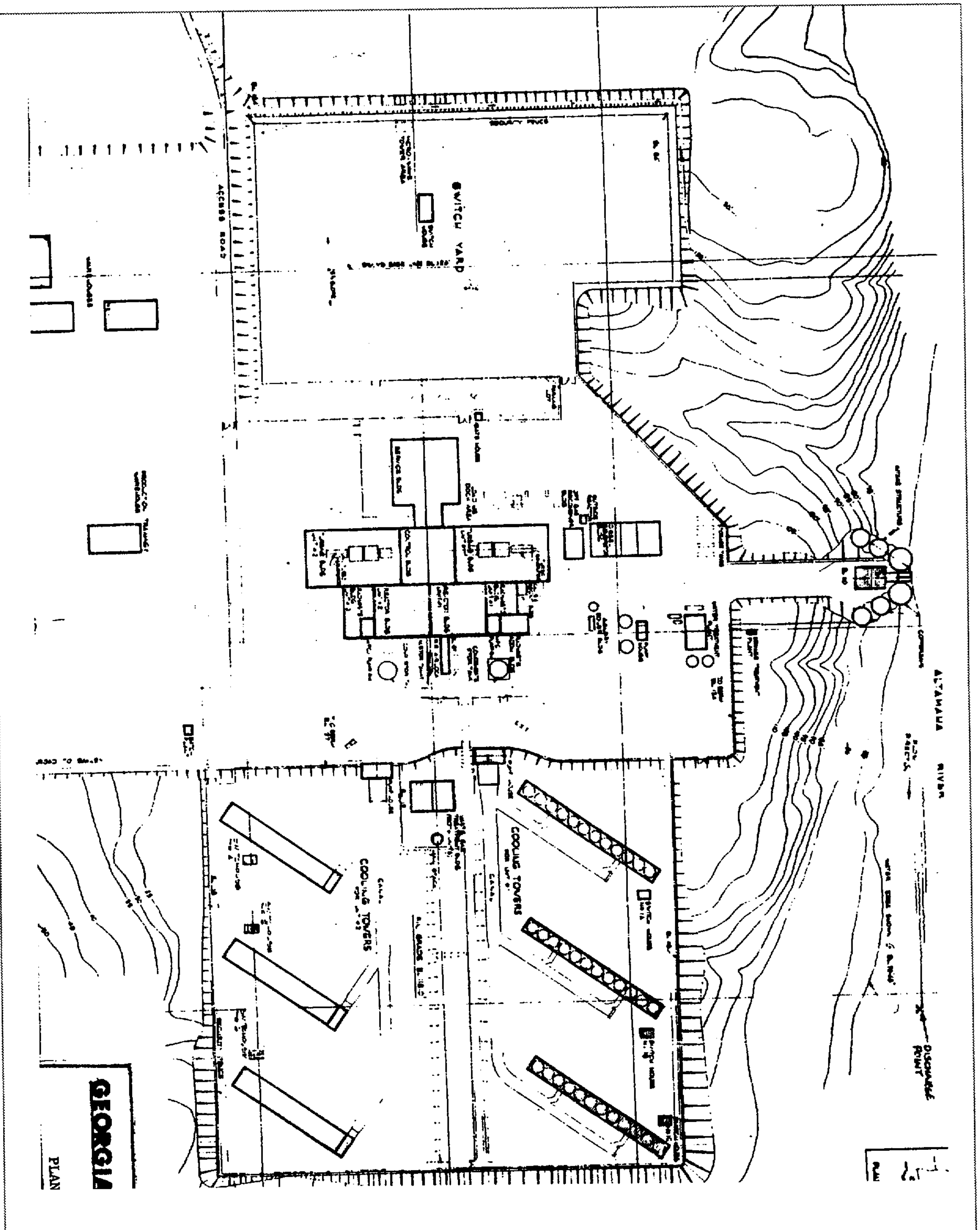
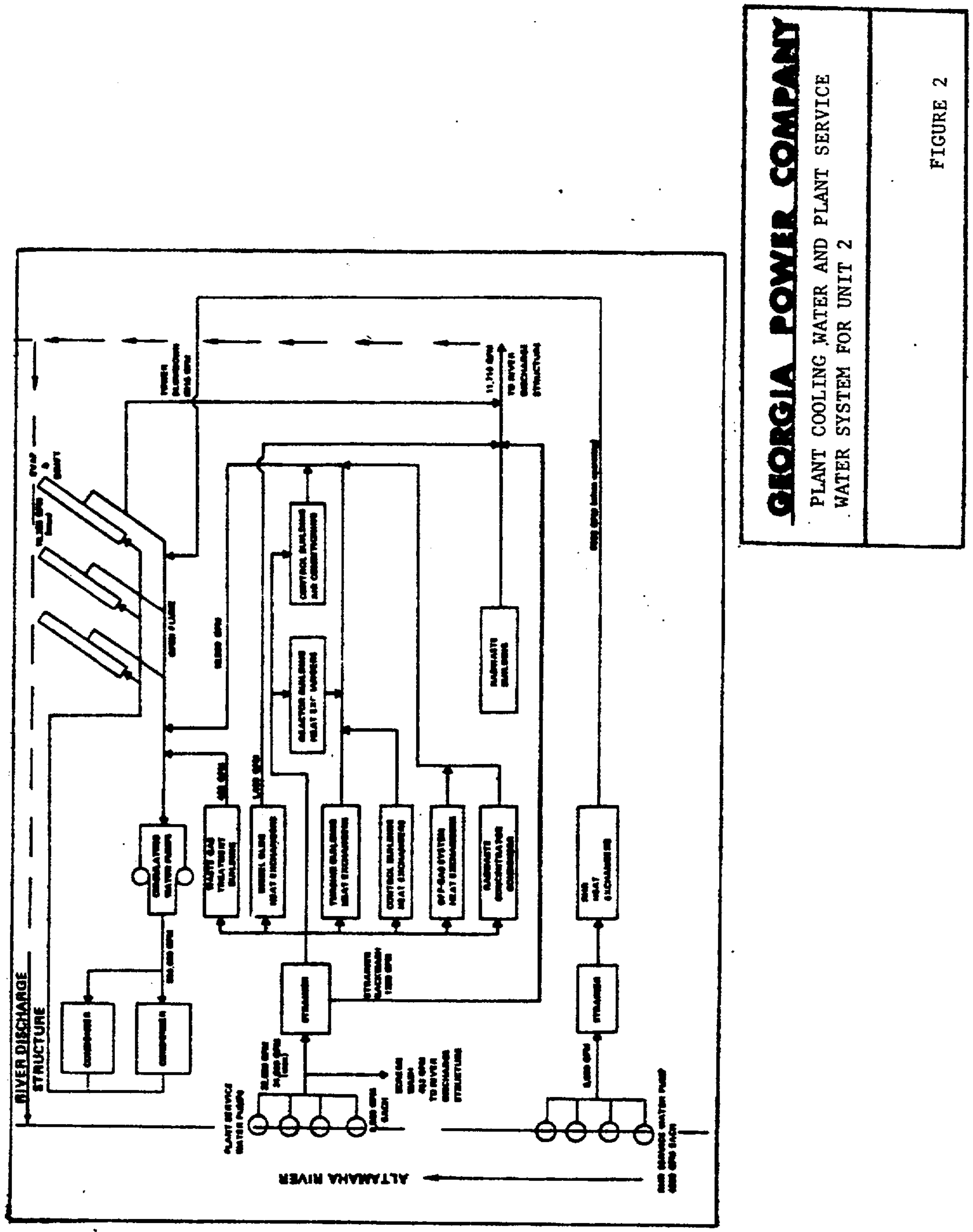


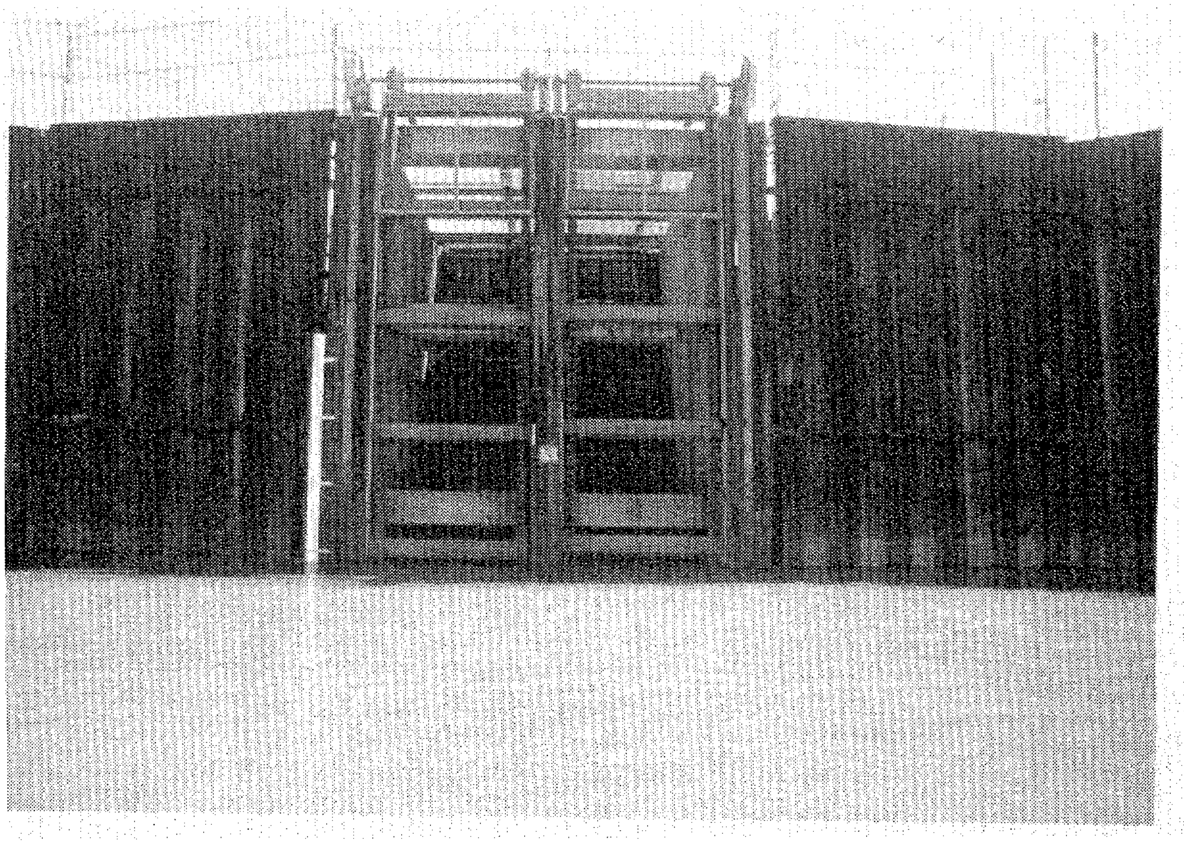
Figure 1A. Plant Edwin I Hatch Plant Layout

Letter C-12. Attachment (page 58 of 73)

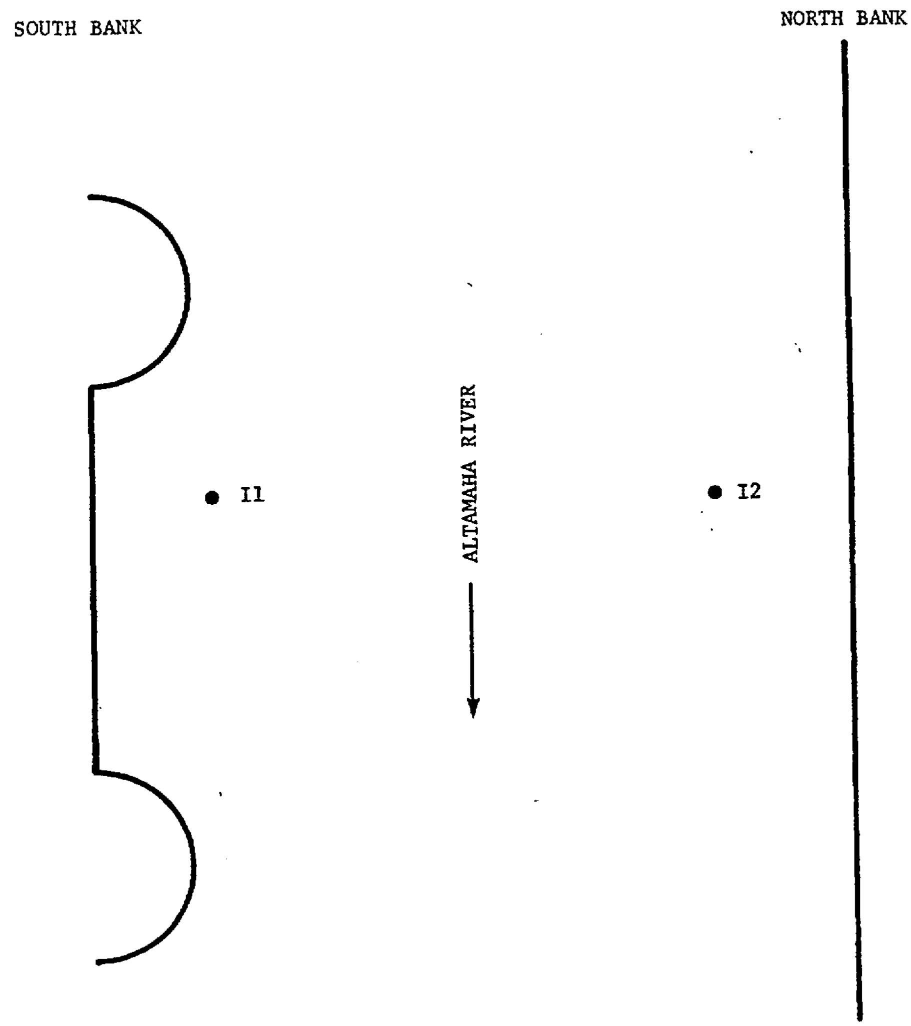


26

Letter C-12. Attachment (page 59 of 73)



Letter C-12. Attachment (page 60 of 73)



GEORGIA POWER COMPANY

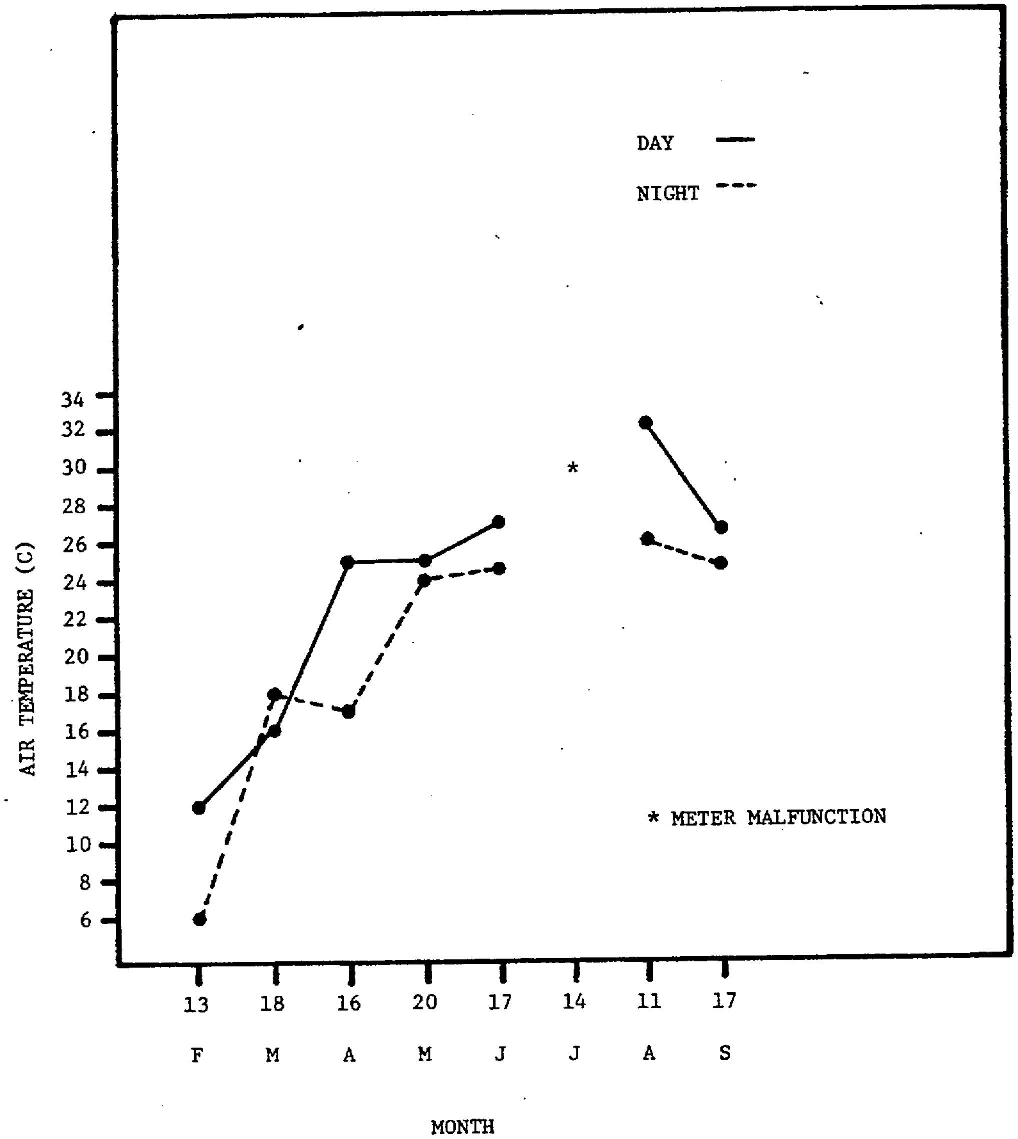
LOCATION OF THE ENTRAINMENT SAMPLING STATIONS ON THE ALTAMAHA RIVER AT

PLANT EDWIN I. HATCH

FIGURE 3

28

Letter C-12. Attachment (page 61 of 73)



GEORGIA POWER COMPANY

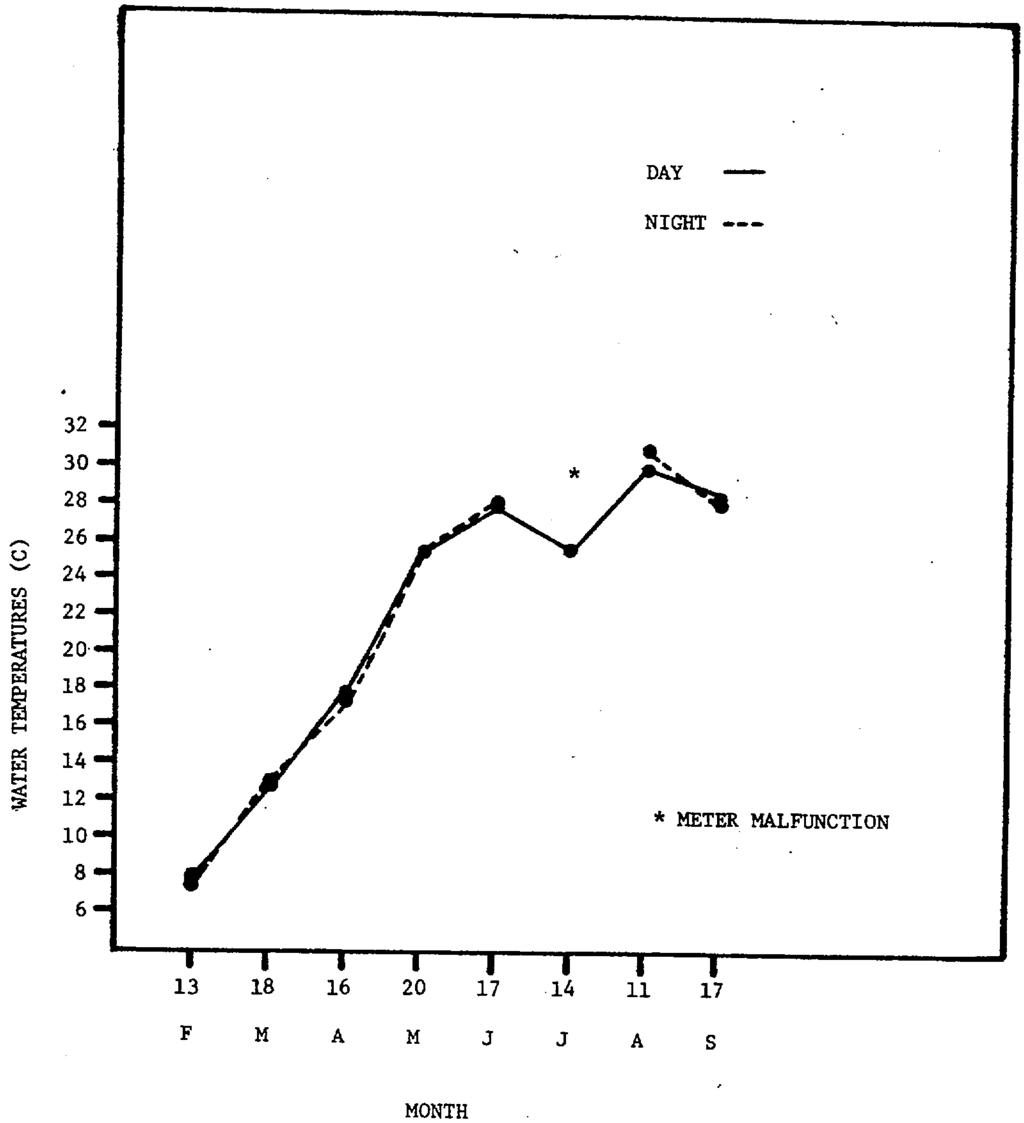
AIR TEMPERATURES FOR THE DAY AND NIGHT ENTRAINMENT SURVEYS ON THE ALTAMAHA RIVER

AT PLANT EDWIN I. HATCH FROM FEBRUARY, 1980 - SEPTEMBER, 1980

FIGURE 4

29

Letter C-12. Attachment (page 62 of 73)



GEORGIA POWER COMPANY

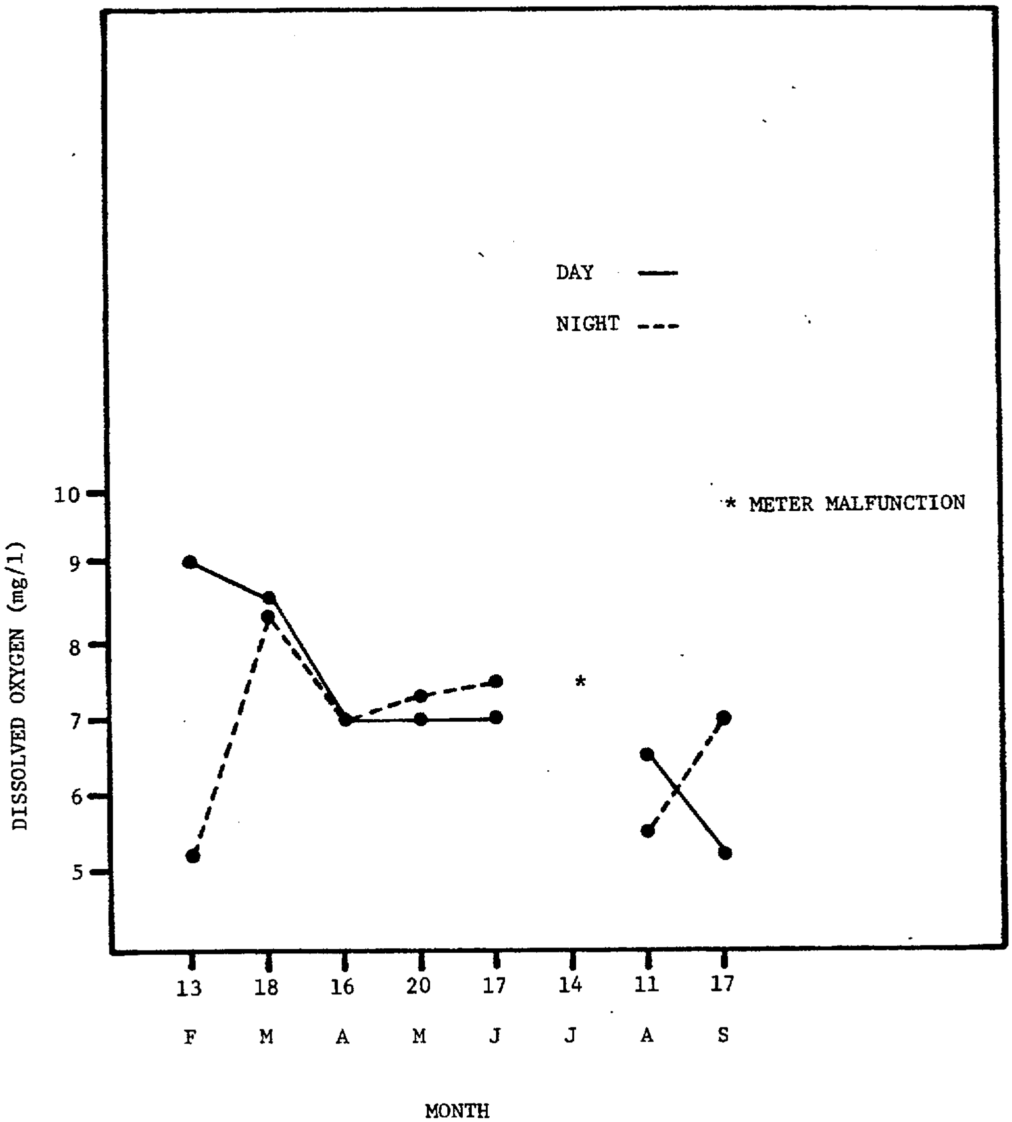
WATER TEMPERATURES FOR THE DAY AND NIGHT ENTRAINMENT SURVEYS ON THE ALTAMAHA RIVER

AT PLANT EDWIN I. HATCH FROM FEBRUARY, 1980 - SEPTEMBER, 1980

FIGURE 5

30

Letter C-12. Attachment (page 63 of 73)



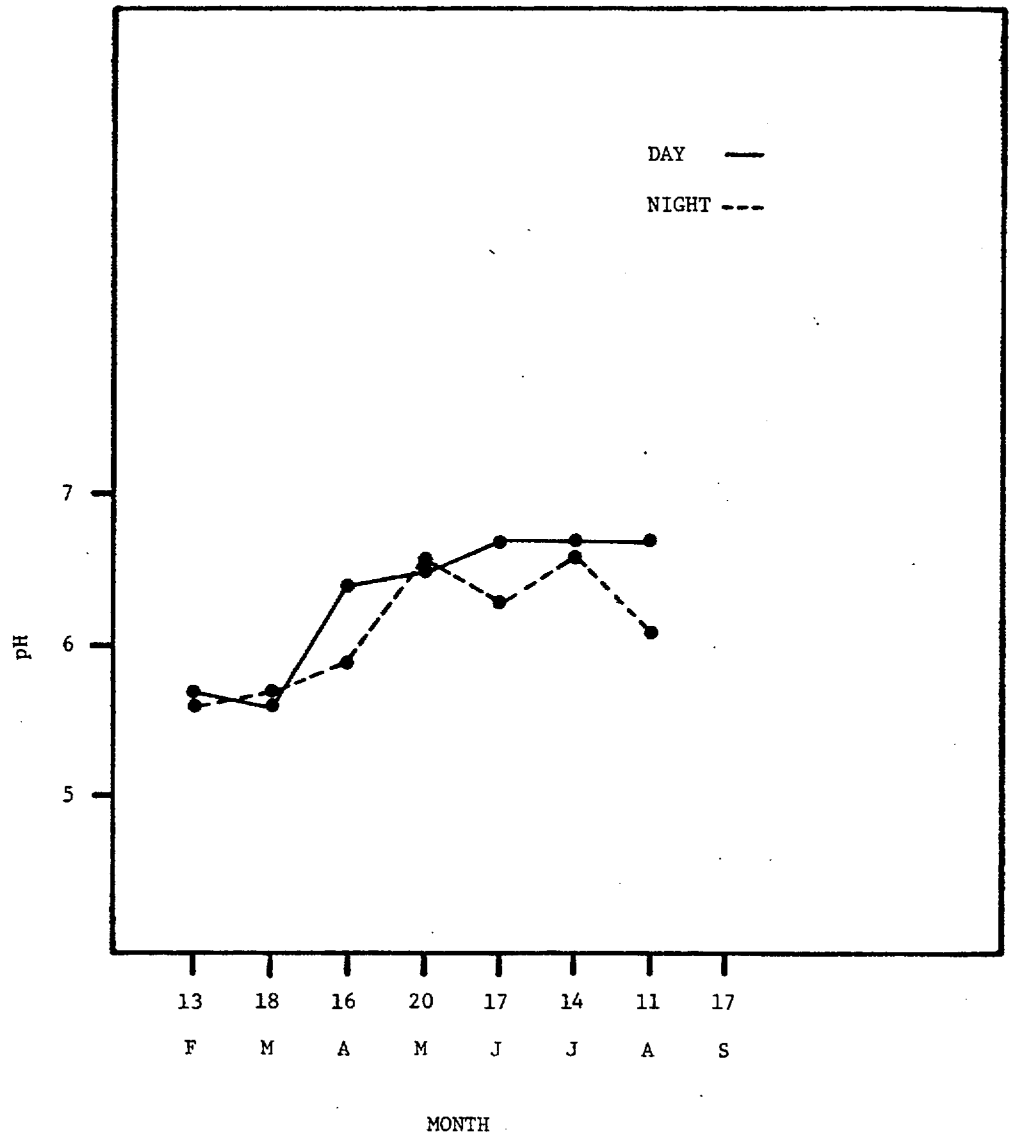
GEORGIA POWER COMPANY

DISSOLVED OXYGEN CONCENTRATIONS FOR THE DAY AND NIGHT ENTRAINMENT SURVEYS ON THE ALTAMAHA RIVER AT PLANT EDWIN I. HATCH FROM FEBRUARY, 1980 - SEPTEMBER, 1980

FIGURE 6

31

Letter C-12. Attachment (page 64 of 73)



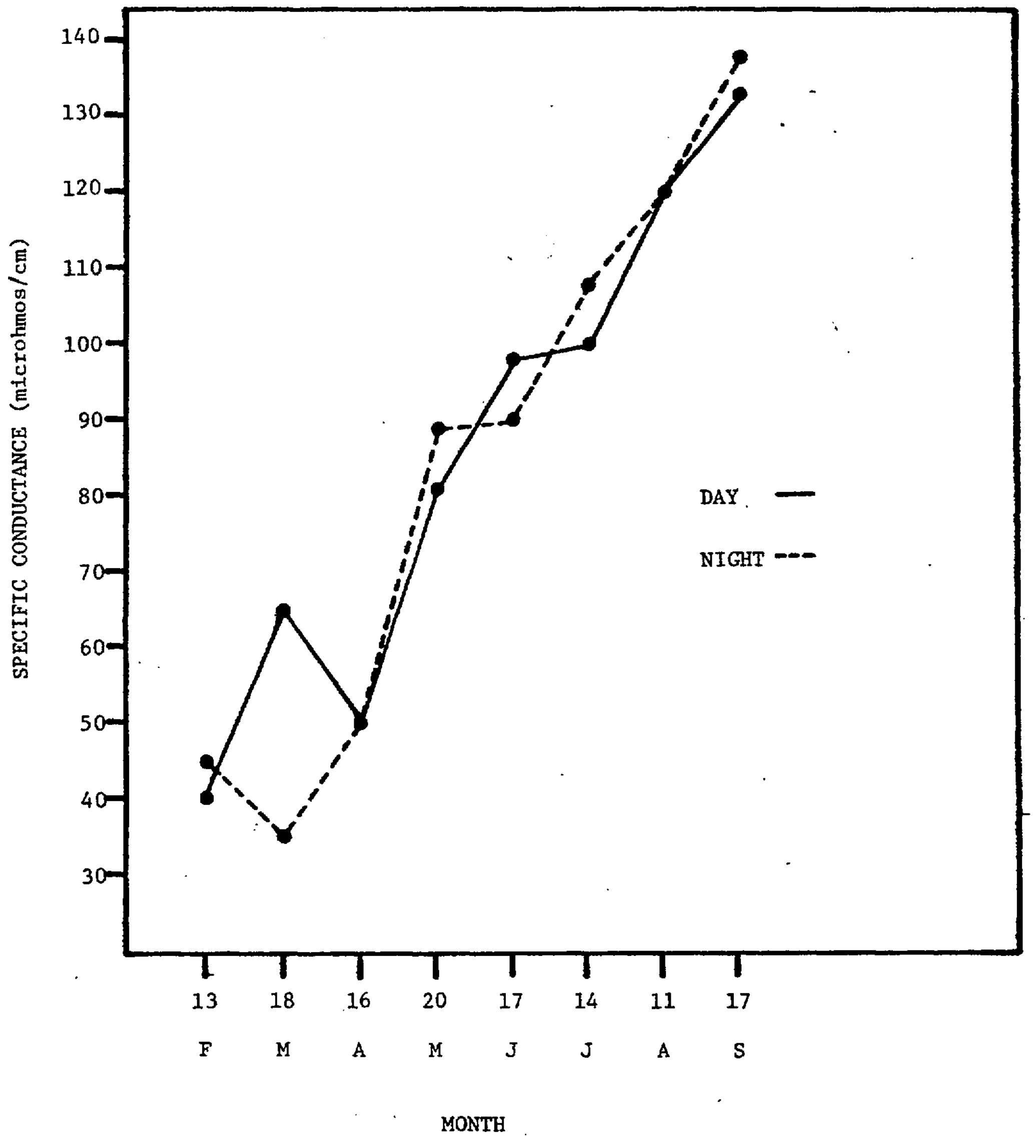
GEORGIA POWER COMPANY

pH VALUES FOR THE DAY AND NIGHT ENTRAINMENT SURVEYS ON THE ALTAMAHA RIVER AT PLANT EDWIN I. HATCH FROM FEBRUARY, 1980 - SEPTEMBER, 1980

FIGURE 7

32

Letter C-12. Attachment (page 65 of 73)



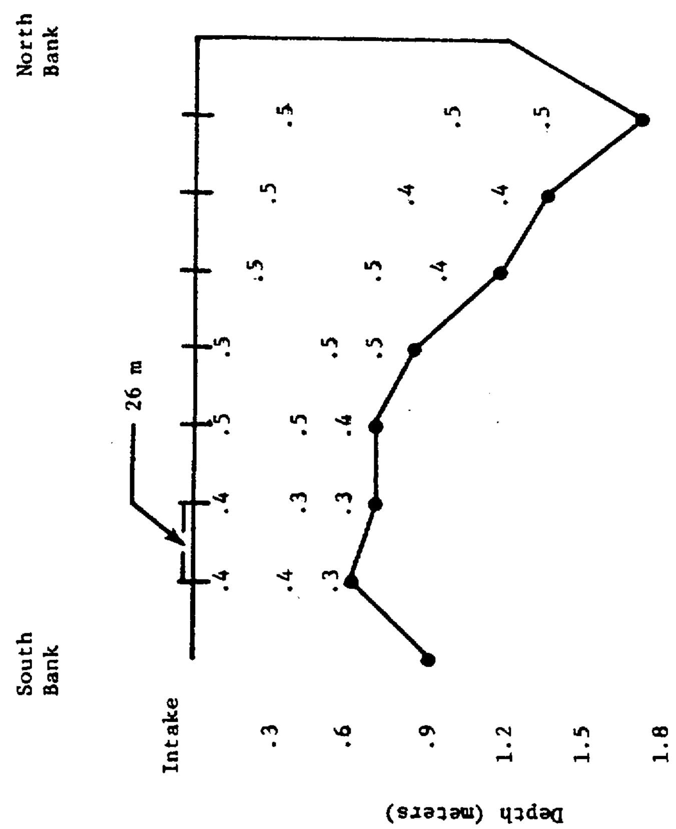
GEORGIA POWER COMPANY

SPECIFIC CONDUCTANCE FOR THE DAY AND NIGHT ENTRAINMENT SURVEYS ON THE ALTAMAHA RIVER AT PLANT EDWIN I. HATCH FROM FEBRUARY, 1980 - SEPTEMBER, 1980

FIGURE 8

33

Letter C-12. Attachment (page 66 of 73)



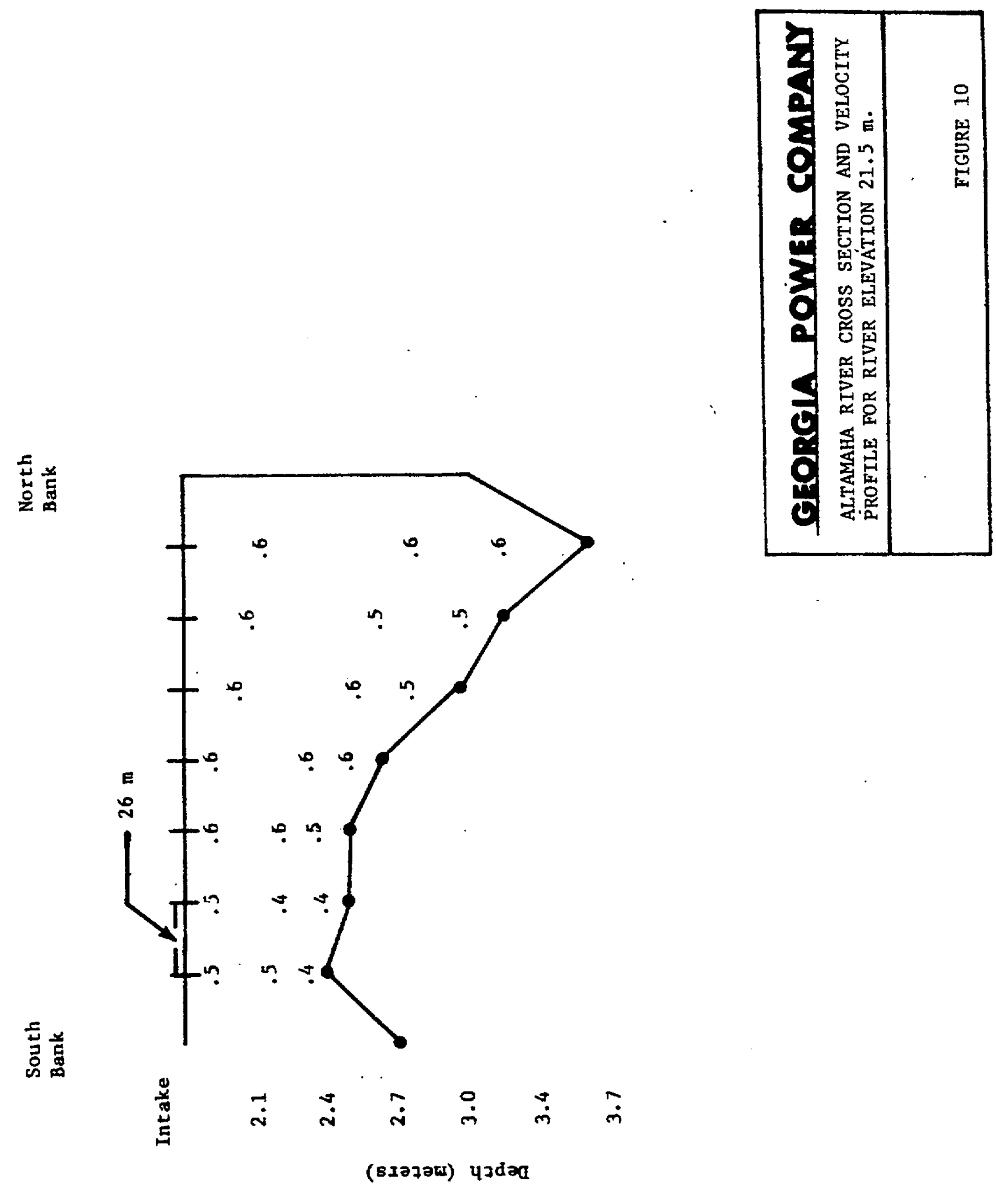
GEORGIA POWER COMPANY

ALTAMAHA RIVER CROSS SECTION AND VELOCITY PROFILE FOR RIVER ELEVATION 19.7 m.

FIGURE 9

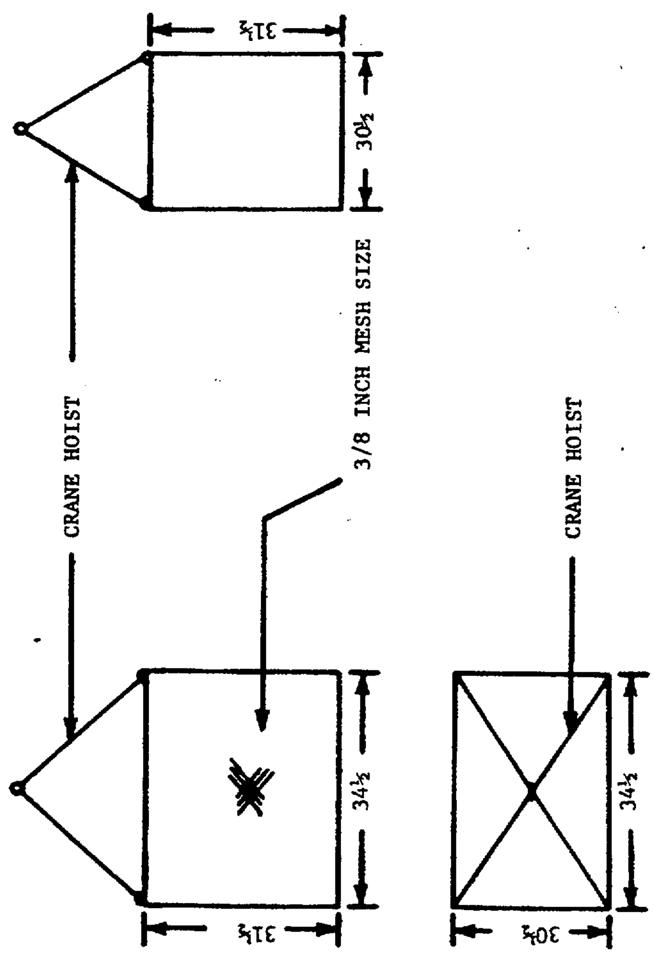
34

Letter C-12. Attachment (page 67 of 73)



35

Letter C-12. Attachment (page 68 of 73)



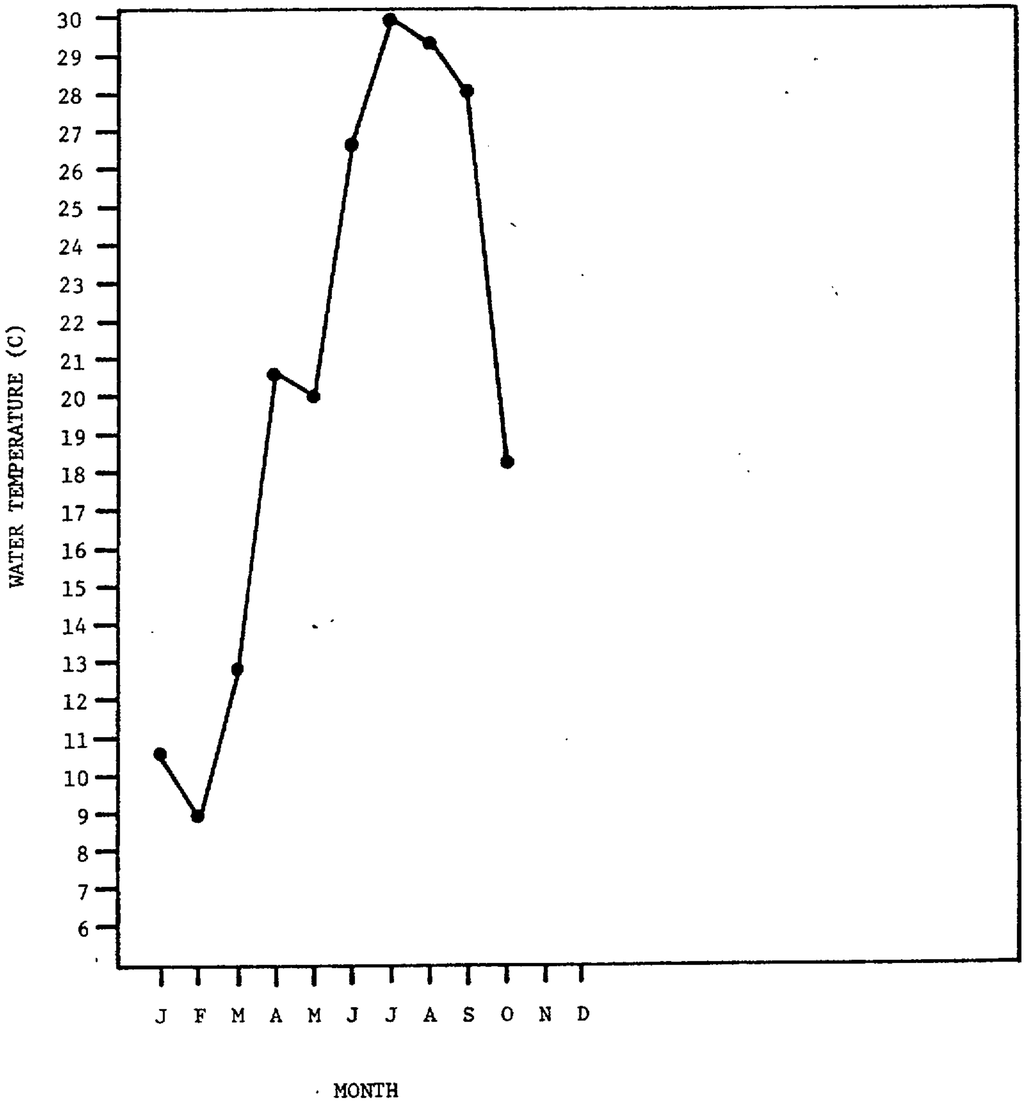
GEORGIA POWER COMPANY

IMPINGEMENT BASKET AT PLANT EDWIN I. HATCH

FIGURE 11

36

Letter C-12. Attachment (page 69 of 73)



GEORGIA POWER COMPANY

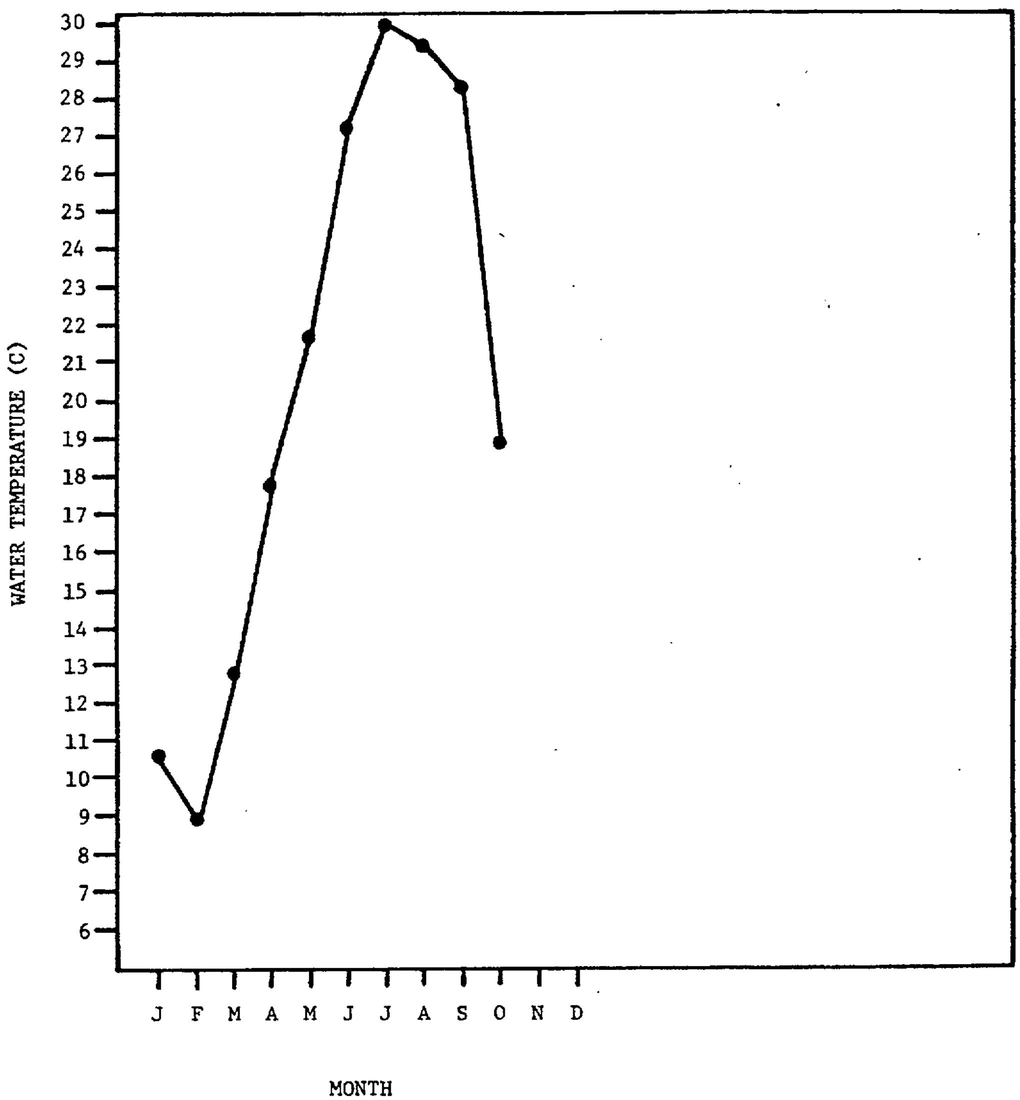
WATER TEMPERATURES FOR THE ALTAMAHA RIVER AT THE BEGINNING OF EACH IMPINGEMENT SURVEY

AT PLANT EDWIN I. HATCH FROM JANUARY, 1980 - DECEMBER, 1980

FIGURE 12

37

Letter C-12. Attachment (page 70 of 73)



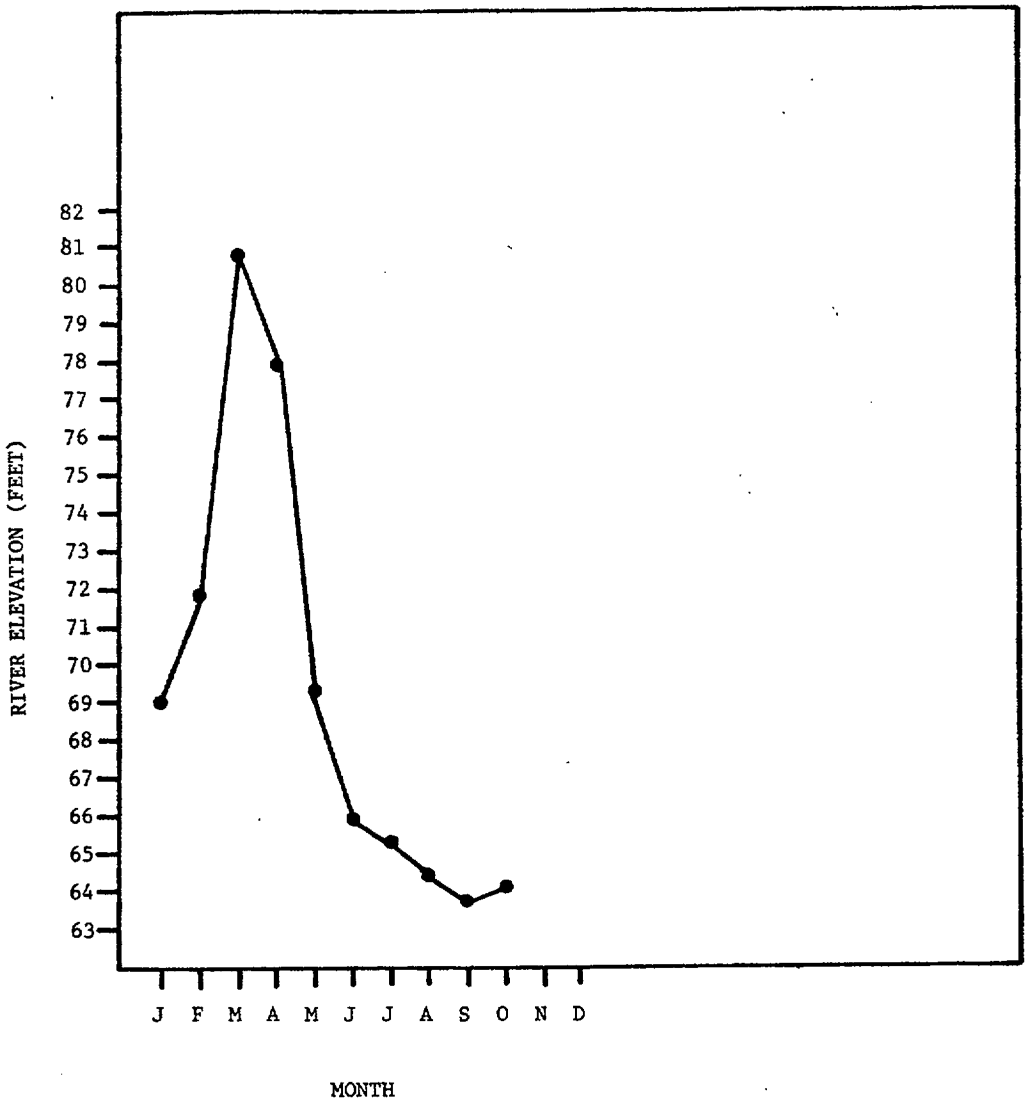
GEORGIA POWER COMPANY

WATER TEMPERATURES FOR THE ALTAMAHA RIVER AT THE END OF EACH IMPINGEMENT SURVEY AT PLANT EDWIN I. HATCH FROM JANUARY, 1980 - DECEMBER, 1980

FIGURE 13

38

Letter C-12. Attachment (page 71 of 73)



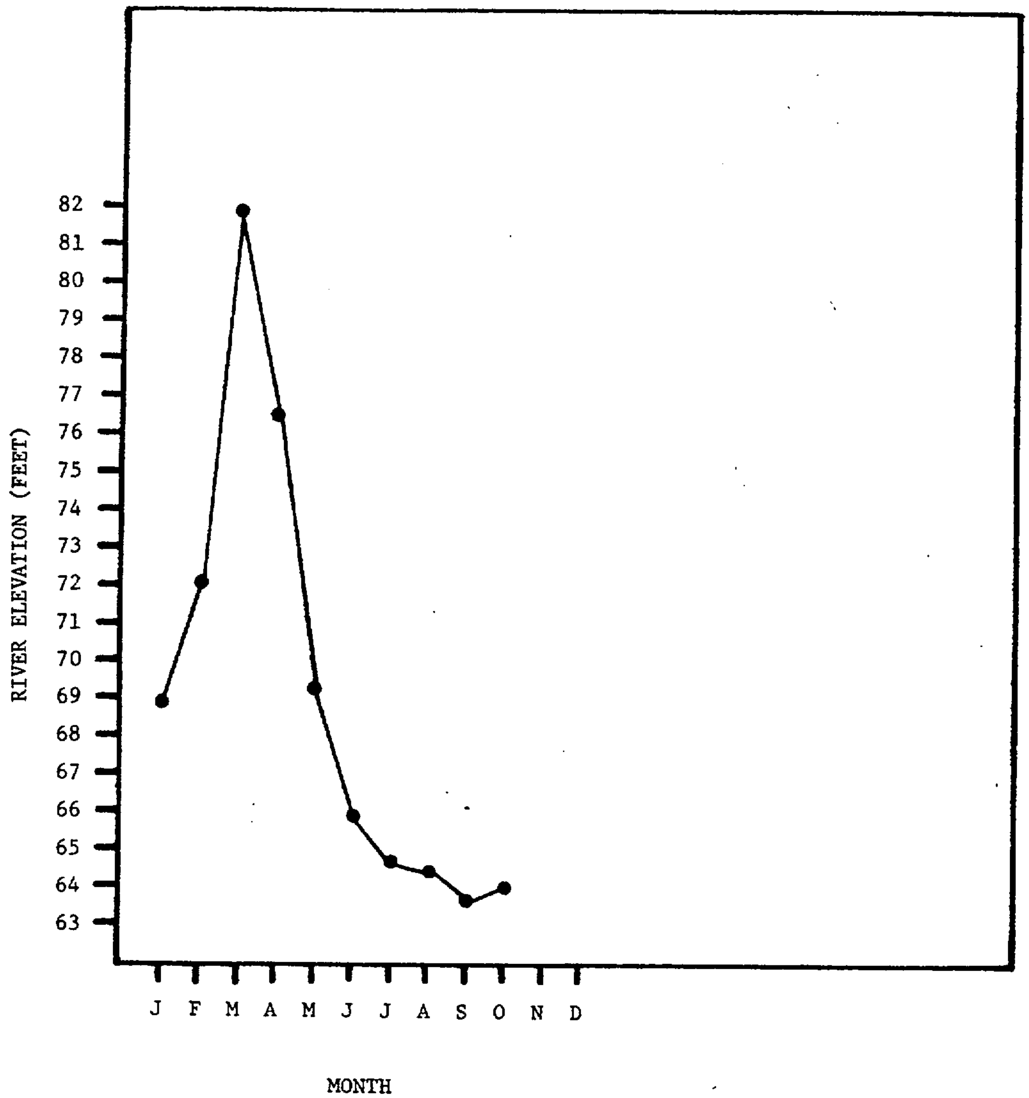
GEORGIA POWER COMPANY

RIVER ELEVATION FOR THE ALTAMAHA RIVER AT THE BEGINNING OF EACH IMPINGEMENT SURVEY AT PLANT EDWIN I. HATCH FROM JANUARY, 1980 - DECEMBER, 1980

FIGURE 14

39

Letter C-12. Attachment (page 72 of 73)



GEORGIA POWER COMPANY

RIVER ELEVATION FOR THE ALTAMAHA RIVER AT THE END OF EACH IMPINGEMENT SURVEY AT

PLANT EDWIN I. HATCH FROM JANUARY, 1980 - DECEMBER, 1980

FIGURE 15

40

Letter C-12. Attachment (page 73 of 73)

ATTACHMENT D. CULTURAL RESOURCES CONSULTATION

Attachment D presents Southern Nuclear Operating Company's request to the Georgia Historic Preservation Officer for of historical and cultural consultations under Section 106 of the National Historic Preservation Act of 1966.

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

September 15, 1999

LRS-99-003

Historic Preservation Division
Georgia Department of Natural Resources
500 The Healey Building
57 Forsyth Street NW
Atlanta, Georgia 30303

Attn: Mr. Ray Luce, State Historic Preservation Officer

Re: License renewal activity for Hatch Nuclear Plant

Southern Nuclear Operating Company ("SNC") is preparing an application to renew the Edwin I. Hatch ("HNP") Nuclear Power Plant operating licenses consistent with the U.S. Nuclear Regulatory Commission ("NRC") regulations. This application would provide for an additional 20 years of operation beyond the current license term. As part of the license renewal process, the NRC requires applicants to identify whether any historic or archeological properties will be affected by the proposed project.

HNP Unit 1 began commercial operation December 31, 1974, and is licensed to operate through August 5, 2014. HNP Unit 2 began commercial operation September 5, 1979, and is licensed through June 13, 2018. The Plant is in Appling County, Georgia, approximately 11 miles north of the town of Baxley. HNP's six transmission lines cross 17 counties in the Coastal Plain of Georgia (see attached figure for details).

The *Final Environmental Statement for Edwin I. Hatch Nuclear Plants Unit 1 and Unit 2* prepared in 1972 by the U.S. Atomic Energy Commission stated that "no archaeologically valuable materials or information" were uncovered during the construction of the plant. The Final Environmental Statement further stated that "... the Georgia Historic Commission has indicated that the project area and the proposed right-of-way for transmission lines connected with the project do not involve, pass through, or pass near any known points of historical or archeological significance." The National Register of Historic Places currently lists three properties in Appling County, Georgia. All of these properties lie within the Baxley town limits, well south of the plant.

Page 1 of 2

Letter D-1. Historic Preservation Division letter (page 1 of 3).

LR-99-03
RE: License renewal activity for Hatch Nuclear Plant
Page 2 of 2

SNC is committed to the preservation of Georgia's historic and archeological properties and expects that operation of HNP through the license renewal period (an additional 20 years) would not adversely affect any such properties. SNC has no plans to alter current operations for the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously-disturbed areas. No additional land disturbance in anticipated in support of license renewal. Accordingly, we request your concurrence with our determination that the license renewal process would have no effect on any historic or archeological properties.

Please do not hesitate to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by October 22, 1999, to enable us to meet our application preparation schedule.

Sincerely,

C. R. Pierce

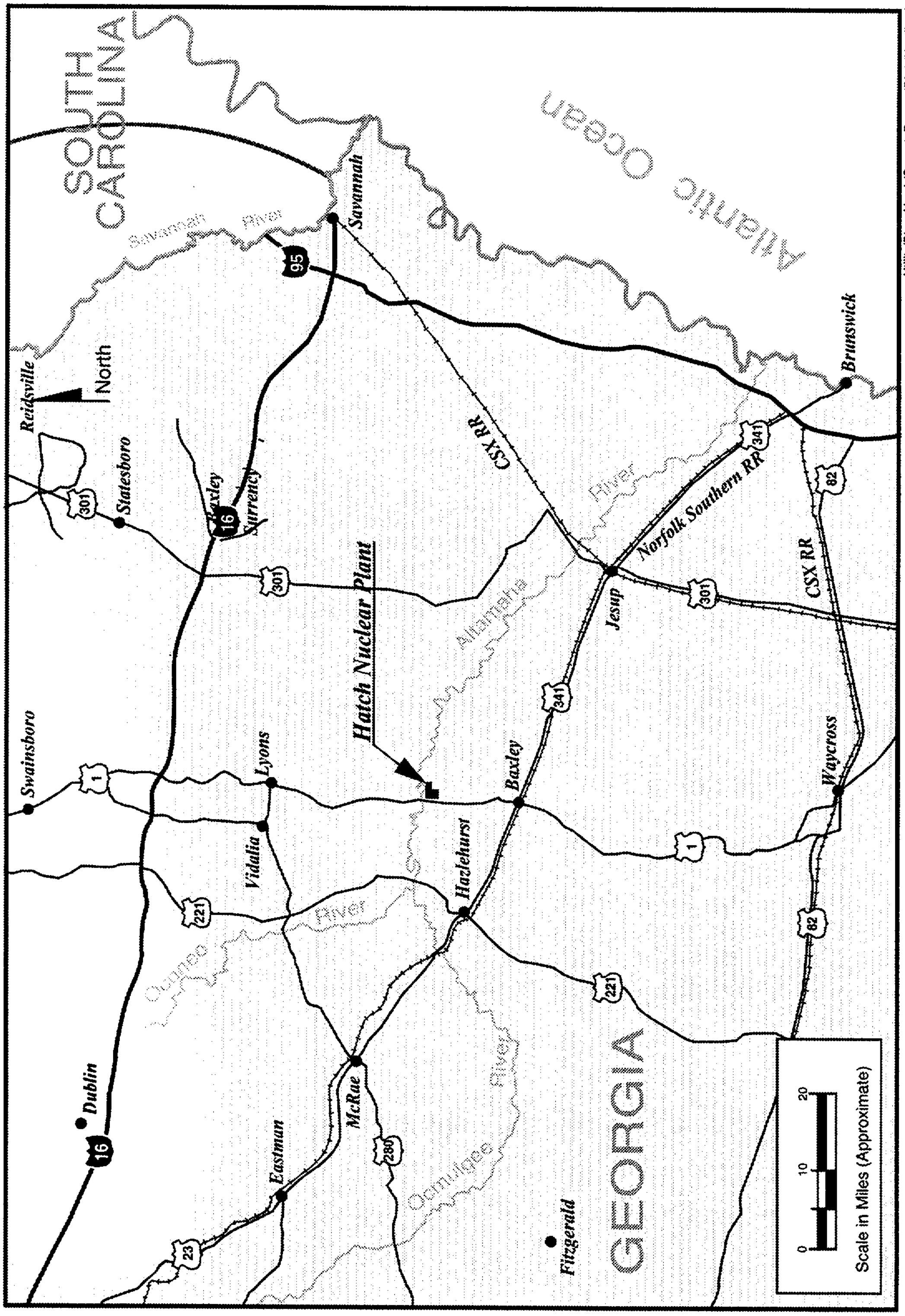
C. R. Pierce
License Renewal Services Manager

CRP/JTD

Attachment

cc: P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter D-1. Historic Preservation Division letter (page 2 of 3).



Edwin I. Hatch Nuclear Plant , 50-mile region.

Letter D-1. Historic Preservation Division letter (page 3 of 3).

Georgia Department of Natural Resources

Lonice C. Barrett, Commissioner

Historic Preservation Division

W. Ray Luce, Division Director and Deputy State Historic Preservation Officer
500 The Healey Building, 57 Forsyth Street, N. W., Atlanta, Georgia 30303
Telephone (404) 656-2840 Fax (404) 657-1040

October 29, 1999

C.R. Pierce
License Renewal Services Manager
Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, AL 35201-1295

Re: License Renewal Activity for Hatch Nuclear Plant
Appling County, Georgia
HP990917-001

Dear Mr. Pierce:

The Historic Preservation Division (HPD) has reviewed the information submitted concerning the proposed operating renewal license of Edwin I. Hatch Nuclear Power Plant located in Appling County, Georgia. Our comments are offered to advise the U.S. Nuclear Regulatory Commission (NRC) and Southern Company on the effects of this undertaking for compliance with Advisory Council regulations 36 CFR Part 800.

HPD concurs with your conclusion that the project will have no significant impact upon historic or archaeological resources which are listed in or eligible for listing in the National Register of Historic Places and are located within the project's area of potential effects.

If we may be of further assistance, please contact Serena Bellew, Environmental Review Associate Planner, at (404) 651-6624.

Sincerely,

W. Ray Luce

W. Ray Luce
Division Director and Deputy State Historic Preservation Officer

WRL:kcs

cc: Jim Davis, Southern Nuclear Operating Company, Inc.
Robin B. Nail, Heart of Georgia RDC

Letter D-2. Southern Nuclear Operating Company, Inc. Letter (page 1 of 1).

ATTACHMENT E. OTHER CONSULTATIONS

Attachment E presents Southern Nuclear Operating Company's request to the Georgia Department of Natural Resources for information regarding thermophilic organisms in the Altamaha River in the vicinity of Plant Hatch.

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

September 15, 1999 LRS-99-004

Watershed Planning and Monitoring Program
Environmental Protection Division
Georgia Department of Natural Resources
7 Martin Luther King Drive SW, Suite 643
Atlanta, GA 30334

Attn: Mr. W. M. Winn, Director

Re: Formal request for information on thermophilic microorganisms in the Altamaha River

Southern Nuclear Operating Company ("SNC") is preparing an application to renew the Edwin I. Hatch ("HNP") Nuclear Power Plant operating licenses consistent with the U.S. Nuclear Regulatory Commission ("NRC") regulations. This application would provide for an additional 20 years of operation beyond the current license term. The plant lies on the west bank of the Altamaha River in Appling County, Georgia, and uses a closed-loop cooling water system that withdraws from and discharges to the Altamaha River. Discharge limits and monitoring requirements for Plant Hatch are set forth in NPDES Permit GA 0004120, which was issued by the Georgia Department of Natural Resources in 1997.

The NRC requires license applicants to provide "...an assessment of the impact of the proposed action [license renewal] on public health from thermophilic organisms in the affected water." The NRC regulations state that "these organisms are not expected to be a problem at most operating plants" but state further that "without site-specific data, it is not possible to predict the effects generically."

SNC believes that Plant Hatch discharge temperatures, which do not exceed 95°F (even in summer), are below those known to be conducive to growth and survival of thermophilic pathogens. Plant operations and plant cooling systems are not expected to change significantly over the license renewal term, and there is no reason to believe that discharge temperatures will increase. However, in strict compliance with NRC regulations, we are requesting any

Page 1 of 2

Letter E-1. Watershed Planning and Monitoring Program letter (page 1 of 3).

LR-99-04
RE: Formal request for information on thermophilic microorganisms in the Altamaha River
Page 2 of 2

information that EPD may have compiled on the presence of thermophilic microorganisms in the Altamaha River in the vicinity of Plant Hatch, including results of any monitoring or special studies that might have been conducted by EPD or its subcontractors. Specifically, SNC requests information on the enteric pathogens *Salmonella* sp. and *Shigella* sp. as well as the *Pseudomonas aeruginosa* bacterium and other less-common aquatic microorganisms that sometimes occur in heated water such as the Legionnaire's disease bacteria (*Legionella* sp.) and free living amoeba of the genus *Naegleria* (esp. *Naegleria fowleri*).

Please feel free to call Mr. Jim Davis of my staff at 205-992-7692, if you have any questions or require any additional information. We would appreciate receiving your input by October 22, 1999, to enable us to meet our application preparation schedule.

Sincerely,

C Pierce

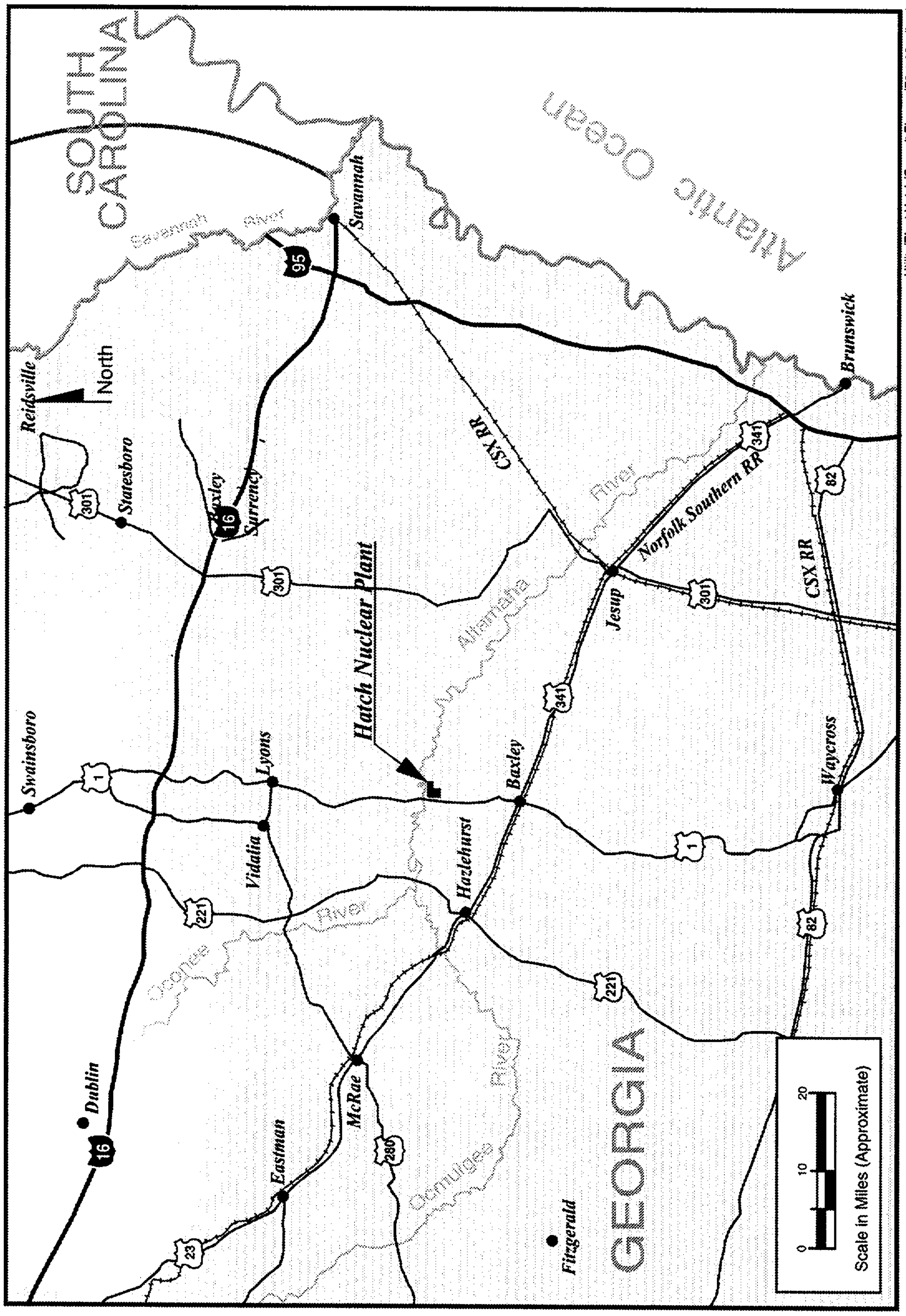
C. R. Pierce
License Renewal Services Manager

CRP/JTD

Attachment

cc: P. R. Moore, Tetra Tech NUS
M. C. Nichols, Georgia Power Company
T. C. Moorer, Southern Nuclear Operating Company
W. C. Carr, Southern Nuclear Operating Company
J. T. Davis, Southern Nuclear Operating Company
D. S. Read, Southern Nuclear Operating Company
D. M. Crowe, Southern Nuclear Operating Company
K. W. McCracken, Southern Nuclear Operating Company
LRS File: R.01.06
NORMS

Letter E-1. Watershed Planning and Monitoring Program letter (page 2 of 3).



Utility/Plant Hatch/Consult Figures/F2-1 50-mile.ai

Edwin I. Hatch Nuclear Plant , 50-mile region.

Letter E-1. Watershed Planning and Monitoring Program letter (page 3 of 3).

Georgia Department of Natural Resources
Environmental Protection Division, Water Protection Branch
4220 International Parkway, Suite 101, Atlanta, Georgia 30354
Alan W. Hallum, Branch Chief
404.675.6232
FAX: 404.675.6247

October 20, 1999

Mr. C. R. Pierce
Southern Nuclear
Operating Company, Inc.
P.O. Box 1295
Birmingham, AL 35201

Re: Request for information in the Altamaha River

We have reviewed your request for information on thermophilic microorganisms in the Altamaha River. Georgia Environmental Protection Division, Watershed Planning and Monitoring Program has not conducted any studies in the Plant Hatch area however, historical data may be available through USEPA STORET system.

If we can be of any further help please do not hesitate to contact me.

Sincerely,

Becky J. Blasius
Becky J. Blasius
Water Protection Division

BJB/bjb

Letter E-2. Southern Nuclear Operating Company, Inc. Letter (page 1 of 1).

ATTACHMENT F: SEVERE ACCIDENT MITIGATION ALTERNATIVES AT THE EDWIN I. HATCH NUCLEAR PLANT

1.0 Methodology

The methodology selected for this analysis involves identifying those SAMA candidates that have the most potential for reducing core damage frequency and person-rem risk. The phased approach consists of:

- Extending the HNP PRA/IPE results to a Level 3 analysis by determining offsite dose and economic baseline risk values,
- Determining the maximum averted risk that is possible based on the HNP baseline risk,
- Identifying potential SAMA candidates based on NRC and industry documents,
- Screening out potential SAMA candidates that are not applicable to the HNP design or are of low benefit in Boiling Water Reactors
- Screening out SAMA candidates whose estimated cost exceeds the maximum possible averted risk,
- Performing a more detailed cost estimate and Level 3 dose and economic risk evaluation of remaining candidates to see if any have a benefit in risk aversion that exceeds the expected cost.

2.0 Level 3 PRA Analysis

The MACCS2 code (Reference 1) was used to perform the level 3 probablistic risk assessment (PRA) for the HNP. The input parameters given with the MACCS2 "Sample Problem A," which included the NUREG-1150 food model (Reference 2), formed the basis for the present analysis. These generic values were supplemented with parameters specific to HNP and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Plant-specific release data included the time-nuclide distribution of releases, release frequencies, and release locations. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and the site evacuation plan (Reference 3). This data was used in combination with site-specific meteorology to simulate the probability distribution of impact risks (exposure and economic) to the surrounding (within 50 miles) population from the large early release accident sequences at HNP.

Population

The population surrounding the plant site was estimated for the year 2030. The distribution was given in terms of population at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, ENE, NE......WNW). The total population for the 160 sectors (10 distances × 16 directions) in the region was estimated as 498,834, the distribution of which is given in Tables 1 and 2.

Table 1. Estimated population distribution within a 10-mile radius of HNP, year 2030.

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile total
N	0	14	38	0	116	540	708
NNE	0	1	0	0	10	400	411
NE	0	0	0	23	39	370	432
ENE	0	0	0	0	3	155	158
E	0	0	0	0	30	30	60
ESE	0	0	46	0	0	306	352
SE	0	0	27	16	61	368	472
SSE	0	0	50	32	163	573	818
S	0	29	185	70	62	2,545	2,891
SSW	0	35	109	83	44	420	691
SW	0	74	31	19	13	312	449
WSW	0	0	44	0	20	542	606
W	0	97	0	180	0	150	427
WNW	0	0	0	51	0	445	496
NW	0	0	0	12	29	534	575
NNW	0	2	136	100	57	490	785
Total	0	252	666	586	647	8,180	10,331

Table 2. Estimated population distribution within a 50-mile radius of HNP, year 2030.

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile total
N	708	15,316	5,979	1,566	15,056	38,625
NNE	411	1,439	2,575	7,994	7,051	19,470
NE	432	5,199	3,784	3,409	51,355	64,179
ENE	158	3,997	5,356	5,603	10,224	25,338
E	60	991	8,894	2,100	77,421	89,466
ESE	352	597	1,657	4,272	11,779	18,657
SE	472	368	2,740	21,220	1,215	26,015
SSE	818	1,235	1,619	5,407	3,601	12,680
S	2,891	8,854	1,923	2,541	45,212	61,421
SSW	691	1,594	7,126	3,286	2,800	15,497
SW	449	2,088	1,666	8,278	28,568	41,049
WSW	606	10,953	1,510	3,476	3,366	19,911
W	427	2,965	2,292	1,948	3,462	11,094
WNW	496	745	2,985	8,320	3,088	15,634
NW	575	1,752	5,818	1,400	6,530	16,075
NNW	785	5,906	4,985	6,450	5,597	23,723
Total	10,331	63,999	60,909	87,270	276,325	498,834

Population projections within 50 miles of HNP were determined using a geographic information system (GIS), U.S Nuclear Regulatory Commission (NRC) sector population data, and county-level population projections. Counties that partially fell within the 50-mile radius were truncated to include only those portions that fell within the 50-mile radius. Population sectors were created for 16 sectors at an interval of 1 mile from 0 to 10 miles, then at 10-mile intervals from 10 miles to 50 miles. The counties were combined with the sectors to determine what counties fell within each sector. The area of each county within a given sector was calculated to determine the county or counties that comprise each sector.

Using the NRC 1990 sector population data for HNP provided in NUREG/CR-6525 (Reference 4), the ratio of the county area to the sector area was multiplied by the 1990 sector population to give the estimated population per sector by county. The 1990 population per county and projected county population for year 2000 are provided in Reference 2. It was assumed that population growth would remain constant to that projected between 1990 and year 2000. Using this population growth rate, projections were made for year 2010, 2020 and 2030 by multiplying the estimated population of the previous decade by the constant growth rate. This resulted in the estimated population for each county within each sector for each decade. All county portions were combined, by sector, to determine the estimated population of each sector for each decade.

Economy

MACCS2 requires the spatial distribution of certain economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) in the same manner as the population. This was done by specifying the data for each of the 29 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 sectors was then the data corresponding to that county which made up the majority of the land in that sector. For 10 sectors, no county encompassed the majority of the area, so conglomerate data (weighted by the fraction of each county in that sector) was defined.

In addition, generic economic data that is applied to the region as a whole was revised from the MACCS2 sample problem input when better information was available. These revised parameters include per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), value of farm and non-farm wealth, and fraction of farm wealth from improvements (e.g., buildings, equipment).

Agriculture

Agricultural production information was taken from the 1997 Agricultural Census (Reference 5). Production within 50 miles of the site was estimated based on those counties within this radius. Production in those counties, which lie partially outside of this area, was multiplied by the fraction of the county within the area of interest. Cotton and tobacco, non-foods, were harvested from 33 percent of the croplands within 50 miles of the site. Of the food crops, legumes (16 percent of total cropland, made up of soybeans and peanuts) and grain (13 percent of the total cropland, made up corn and wheat) were harvested from the largest areas.

The duration of the growing seasons were obtained from the Atkinson County Extension Service. MACCS2 does not allow the use of split growing seasons. Accordingly, the beginning and total duration of each MACCS food category was estimated. The category growing seasons used in the analysis were: 9 months beginning in March for grains, stored forage and pasture; 10 months beginning in February for green leafy vegetables; and 7 months beginning in April for other food crops including legumes, roots and tubers.

Nuclide Release

The core inventory at the time of the accident was based on the input supplied in the MACCS Users Guide (Reference 1). The core inventory (Table 3) corresponds to the end-of-cycle values for a 3578-MWth BWR plant. A scaling factor of 0.772 was used to provide a representative core inventory for the 2763-MWth HNP. Table 3 includes the 3578-MWth BWR core and the estimated HNP core inventory. Release frequencies (1.79×10-6, 7.42×10-7, 1.66×10-7, 7.42×10-7, and 9.24×10-10 for sequences 2, 4, 5, 11, and 15, respectively) and nuclide release fractions (of the core inventory) were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from large early release sequences 2, 4, 5, 11 and 15. HNP nuclide release categories were related to the MACCS categories as shown in Table 4.

Table 3. Estimated HNP core inventory.

Nuclide	Core Inventory (Bequerels)	Nuclide	Core Inventory (Bequerels)
Co-58	1.563×10^{16}	Te-131m	3.906×1017
Co-60	1.871×10^{16}	Te-132	3.819×1018
Kr-85	2.562×10^{16}	I-131	2.639×1018
Kr-85m	9.315×10^{17}	I-132	3.878×1018
Kr-87	1.693×10^{18}	I-133	5.540×1018
Kr-88	2.287×10^{18}	I-134	6.064×1018
Rb-86	1.434×10^{15}	I-135	5.214×1018
Sr-89	2.837×10^{18}	Xe-133	5.548×1018
Sr-90	2.008×10^{17}	Xe-135	1.318×1018
Sr-91	3.685×10^{18}	Cs-134	4.323×1017
Sr-92	3.850×10^{18}	Cs-136	1.159×1017
Y-90	2.149×10^{17}	Cs-137	2.587×1017
Y-91	3.462×10^{18}	Ba-139	5.107×1018
Y-92	3.865×10^{18}	Ba-140	5.037×1018
Y-93	4.395×10^{18}	La-140	5.140×1018
Zr-95	4.556×10^{18}	La-141	4.747×1018
Zr-97	4.691×10^{18}	La-142	4.566×1018
Nb-95	4.311×10^{18}	Ce-141	4.574×1018
Mo-99	4.971×10^{18}	Ce-143	4.453×1018
Tc-99m	4.290×10^{18}	Ce-144	2.967×1018
Ru-103	3.767×10^{18}	Pr-143	4.359×1018
Ru-105	2.513×10^{18}	Nd-147	1.947×1018
Ru-106	1.025×10^{18}	Np-239	5.805×1019
Rh-105	1.867×10^{18}	Pu-238	4.037×1015
Sb-127	2.376×10^{17}	Pu-239	1.023×1015
Sb-129	8.249×10^{17}	Pu-240	1.282×1015
Te-127	2.301×10^{17}	Pu-241	2.206×1017
Te-127m	3.098×10^{16}	Am-241	2.242×1014
Te-129	7.740×10^{17}	Cm-242	5.922×1016
Te-129m	2.035×10^{17}	Cm-244	3.195×1015

Table 4. MACCS release categories vs. HNP release categories.

MACCS Release Categories	HNP Release Categories
Xe/Kr	1 – noble gases and inert aerosols
I	2 – CsI and RbI
Cs	6 – CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – Lanthanides
Ce	9 – CeO_2
Ba	7 – BaO
Sb (supplemental category)	10 – Sb

Multiple release duration periods were defined which most closely represented the duration of the majority of each category's releases while keeping the number of intervals minimal. Conservative approximations were made to assure that the numerical release periods were no longer than those indicated in the figures. In all cases, the cumulative released material for each category indicated on the figures was simulated.

The reactor building dimensions are 155 × 149 × 154 feet (height). All modeled releases except sequence 15 were released at ground level. Sequence 15 was released through the stack, the height of which is 100 meters. The thermal content of each of the releases was conservatively assumed as to be the same as ambient, i.e., buoyant plume rise was not modeled.

Evacuation

Scram for each sequence was taken as time 0 relative to the core containment response times. A General Emergency is assumed to be at the time of core uncovery except for sequences 2, 11, and 15. A General Emergency is declared at 1 hour for Sequence 2, and at 15 minutes (after scram) for Sequences 11 and 15.

The MACCS2 Users Guide input parameters of 95 percent of the population within 10 miles of the plant (Emergency Planning Zone) evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (i.e., Calvert Cliffs, Reference 6) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone (Reference 6). The evacuees are assumed to begin evacuation 45 minutes (notification + preparation time, Table A5-3, Reference 3) after a general emergency has been declared and are evacuated at a radial speed of 2.5 m/sec. This speed is taken as the minimum speed for any evacuation zone for special need persons evacuating under adverse conditions.

Meteorology

HNP site meteorology from 1997 was used to create the one-year sequential hourly data set used in MACCS2. Wind speed and direction from the 10-meter sensor were combined with precipitation (hourly cumulative) and atmospheric stability (specified according to the vertical temperature gradient as measured between the 60-meter and 10-meter levels). Hourly stability was classified according to the scheme used by the NRC (Reference 6). The supplied one-year data set contained 16 hours (of a total of 8,760 hours) during which at least one parameter was missing. In such cases, the missing parameter was filled in with the previous hour's value. No parameter was missing for two consecutive hours.

Atmospheric mixing heights were specified for AM and PM hours. These values were taken as 400 and 1500 meters, respectively (Reference 7)

MACCS2 Results

The resulting annual risk from HNP early release sequences 2, 4, 5, 11 and 15 (and their sum) are as provided below in Table 5. The largest risks are from sequence 2, owing to its greatest (of those sequences analyzed) probability of occurrence. Sequence 2 contributes more than half of the sum of the risks from these large early releases.

Table 5. Results of HNP Level 3 PRA analysis.

Sequence	2	4	5	11	15	Sum of annual risk
Population dose risk (person-rem)						
0-50 miles	1.89	0.76	0.19	0.52	0.00104	3.372
Total economic cost risk ($)						
0-50 miles	5,546	1,974	691	1,040	2.59	9,262

Quantification of the base case shows a baseline Core Damage Frequency (CDF) of 1.6384x10-5 based on 10,721 cutsets (accident scenarios). The baseline Large Early Release Frequency (LERF) is 2.7030x10-6 based on 5,278 cutsets. MACCS2 calculated the annual baseline population dose risk within 50 miles at 3.372 person-rem. The total annual economic risk was calculated at $9,262.

3.0 Determination of Present Value

This Section explains how SNC calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). SNC also used this analysis to establish the maximum benefit that a SAMA could achieve if it eliminated all HNP risk.

Offsite Exposure Cost

The baseline annual offsite exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem (Reference 8, Section 5.7.1.2), and discounting to present value using NRC standard formula (Reference 8, Section 5.7.1.3):

$W_{pha} = C \times Z_{pha}$

Where:

W_{pha} = monetary value of public health risk after discounting
C = $[1-\exp(-rt_f)]/r$
T_f = years remaining until end of facility life = 20 years
r = real discount rate (as fraction) = 0.07/year
Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

The calculated value for C using 20 years and a 7 percent discount rate is 10.76. Therefore, calculating the discounted monetary equivalent of accident risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (10.76). The calculated offsite exposure cost is $72,565.

Offsite Economic Cost

The Level 3 analysis showed an annual offsite economic risk of $9,262. Calculated values for offsite economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $99,659.

Onsite Exposure Cost

SNC evaluated occupational health using the NRC methodology in Reference 8, Section 5.7.3, which involves separately evaluating "immediate" and long-term doses.

Immediate Dose - For the case where the plant is in operation, the equations that NRC recommends using (Reference 8, Sections 5.7.3 and 5.7.3.3) is:

Equation 1:

$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$

Where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rem/event)
$_S$ = subscript denoting status quo (current conditions)
$_A$ = superscript denoting after implementation of proposed action
r = real discount rate
t_f = years remaining until end of facility life.

The values used in the HNP analysis are:

R = $2,000/person-rem
r = 0.07
D_{IO} = 3,300 person-rem/accident (best estimate)
t_f = 20 years (license extension period)
F = 1.64×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the immediate dose cost is:

$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$
$= 2{,}000*1.64\times10^{-5}*3{,}300*\{[1 - \exp(-0.07*20)]/0.07\}$
= $1,164

Long-Term Dose - For the case where the plant is in operation, the NRC equations (Reference 8, Sections 5.7.3 and 5.7.3.3) is:

Equation 2:

$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$

Where:

W_{IO} = monetary value of accident risk avoided long-term doses, after discounting, $
m = years over which long-term doses accrue

The values used in the HNP analysis are:

R = $2,000/person-rem
r = 0.07
D_{LTO} = 20,000 person-rem/accident (best estimate)
m = "as long as 10 years"
t_f = 20 years (license extension period)
F = 1.64×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the long-term dose is:

$W_{LTO} = R\,(FD_{LTO})_S\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$
$= 2{,}000*1.64\times10^{-5}*20{,}000*\{[1 - \exp(-0.07*20)]/0.07\}\{[1 - \exp(-0.07*10)]/0.07*10\}$
= $5,073

Total Occupational Exposure - Combining Equations 1 and 2 above and using the above numerical values, the total accident related on-site (occupational) exposure avoided (W_O) is:
$W_O = W_{IO} + W_{LTO} =$ (\$1,164 + \$5,073) = \$6,237

Onsite Cleanup and Decontamination Cost

The net present value that NRC provides for cleanup and decontamination for a single event is \$1.1 billion, discounted over a 10-year cleanup period (Reference 8, Section 5.7.6.1). NRC uses the following equation in integrating the net present value over the average number of remaining service years:

$U_{CD} = [PV_{CD}/r][1\text{-}\exp(-rt_f)]$

Where:

PV_{CD} = Net present value of a single event
r = real discount rate
t_f = years remaining until end of facility life.

The values used in the HNP analysis are:

$PV_{CD} = \$1.1\text{x}10^9$
r = 0.07
t_f = 20

The resulting net present value of cleanup integrated over the license renewal term, $\$1.2\text{x}10^{10}$, must multiplied by the total core damage frequency of $1.64\text{x}10^{-5}$ to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$193,973.

Replacement Power Cost

Long-term replacement power costs was determined following the NRC methodology in Reference 8 Section 5.7.6.2. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$PV_{RP} = [\$1.2E + 08/r] * [1 - \exp(-rt_f)]^2$

Where:

PV_{RP} = net present value of replacement power for a single event, (\$)
R = 0.07
t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$U_{RP} = [PV_{RP} /r] * [1 - \exp(-rt_f)]^2$

Where:

U_{RP} = net present value of replacement power over life of facility (\$-year)

After applying a correction factor to account for HNP's size relative to the "generic" reactor described in NUREG/BR-0184 (i.e., 845 MWe/910 MWe), the replacement power costs are determined to be 7.33E + 09 (\$-year). Multiplying this value by the CDF (1.64E-05) results in a replacement power cost of \$120,041.

Baseline Screening

The sum of the baseline costs is as follows:

Offsite exposure cost = $72,565
Offsite economic cost =$99,659
Onsite exposure cost = $6,237
Onsite cleanup cost = $193,973
Replacement Power cost = $120,041
Total cost = $492,476

SNC rounded this value up to $500,000 to use in screening out SAMAs that are not economically feasible; if the estimated cost of implementing a SAMA exceeded $500,000, SNC discarded it from further analysis. Exceeding this threshold would mean that a SAMA would not have a positive net value even if it could eliminate all severe accident costs.

4.0 SAMA Candidates and Screening Process

An initial list of 115 SAMA candidates was developed from lists of Severe Accident Mitigation Design Alternatives at other nuclear power plants, NRC documents, and documents related to advanced power reactor designs. This initial list was then screened to remove those that we not applicable to the HNP plant due to design differences.

Twenty-six of the initial 115 candidate SAMAs were removed from further consideration as they did not apply to the BWR-4/Mark I design used at HNP. An additional nine candidates were removed from consideration because they were related to mitigation of an Intersystem Loss of Coolant Accident (ISLOCA). According to NRC Information Notice 92-36 and its supplement, ISLOCA contributes little risk for boiling water reactors because of the lower primary pressures.

Eleven SAMA candidates were related to Reactor Coolant Pump seal leakage. NUREG-1560 indicates that although RCP seal leakage is important for PWRs, recirculation pump leakage does not significantly contribute to core damage frequency in BWRs. Therefore, these eleven candidates were removed from further consideration.

Sixteen SAMA candidates were found to be in place at HNP and were thus dropped from further consideration. Ten SAMA candidates were of sufficient similarity to other SAMA candidates that they were either combined or dropped from further consideration.

This left 43 unique SAMA candidates that were applicable to HNP and were of potential value in averting the risk of severe accidents. A preliminary cost estimate was prepared for each of these candidates to focus on those that had the possibility of having a positive benefit and to eliminate those whose costs were clearly beyond the possibility of any corresponding benefit.

When the screening cutoff of $500,000 was applied, 27 candidates were eliminated that were more expensive than any possible offsetting benefit. This left 16 candidates for further analysis.

Table 6 shows the disposition of the initial set of candidate SAMAs, including an indication of the screening criterion that was applicable for those candidate SAMAs that were removed fromcirculation.

5.0 Level II SAMA Analysis

For each of the 16 remaining SAMA candidates, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidate changes upon the plant safety model.

Table 6. Disposition of initial SAMAs investigated.

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA to reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	N/A	—
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA to reduce the potential for RCP seal damage due to pump bearing failure.	B	—
3	Enhance loss of component cooling procedure to present desirability of cooling down RCS prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.	B	—
4	Additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).	B	—
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.	N/A	—
5A	Procedures changes to allow cross connection of motor cooling for RHRSW pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW.	C (1.4.1 of IPE)	—
6	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend component cooling heatup.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.	B	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
7	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil	N/A	—
8	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to charging pump seals.	N/A	—
9	Add redundant DC Control Power for PSW Pumps C & D	SAMA would increase reliability of PSW and decrease core damage frequency due to a loss of SW.	None	2-7
10	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or service water or from a station blackout event.	B	—
11	Use existing hydro test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.	B	—
12	Replace ECCS Cooling System pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system.	N/A	—
13	Install improved RCS pumps seals.	RCP seal O-ring constructed of improved materials would reduce probability of RCP seal LOCA	B	—
14	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.	B	—
15	Prevent centrifugal charging pump flow diversion from the relief valves.	If relieve valve opening causes a flow diversion large enough to prevent RCP seal injection, then the modification would reduce the frequency of the loss of RCP seal cooling.	B	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
16	Change procedures to isolate RCP seal letdown flow on loss of component cooling, an guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.	B	—
17	Implement procedures to stagger HPSI pump use after a loss of service water.	SAMA would allow HPSI to be extended after a loss of service water.	N/A	—
18	Use fire protection system pumps as a backup seal injection and high pressure make-up.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.	B	—
19	Procedural guidance for use of cross-tied component cooling or service water pumps.	SAMA would reduce the frequency of the loss of component cooling water and service water.	C	(2-10)
20	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.	D (various SAMAs for specific systems)	—
21	Improved ability to cool the residual heat removal heat exchangers	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the fire protection system or by installing a component cooling water cross-tie.	D—29 and 30	—
22	Provide reliable power to Control Building fans	SAMA would increase availability of control room ventilation on a loss of power.	None	2-15
23	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.	D—22 and 25	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
24	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of Control Building HVAC).	C	—
25	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC.		
		Option 1: Install high temp alarm	None	2-5A
		Option 2: Redundant louver and thermostat	None	2-5B
26	Create ability to switch fan power supply to direct current (DC) in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling system room at Fitzpatrick Nuclear Power Plant.	N/A	—
27	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of RWST availability.	N/A	—
28	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWT, when full CS flow is not needed	N/A	—
29	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal.	E	—
30	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.	E	—
31	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.	E	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
32	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.	C	—
33	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed.		
		Option 1: Gravel Bed Filter	E	—
		Option 2: Multiple Venturi Scrubber	E	—
34	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.	E	—
35	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either a new, independent power supply, a nonsafety-grade portable generator, existing station batteries, or existing AC/DC independent power supplies.	E	—
35A	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.	E (Unit 1) C (Unit 2)	—
36	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.	E	—
37	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	SAMA would ensure that molten core debris escaping form the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.	E	—
38	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.	E	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
39	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.	E	—
40	Enhance fire protection system and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.	C	(2-4)
41	Create a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	E	(2-16)
42	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	D—See 41	—
43	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.	N/A	—
44	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur.	E	—
45	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.	C	—
46	Use the fire protection system as a back-up source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.	None	2-2

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
47	Install a secondary containment filter vent.	SAMA would filter fission products released from primary containment.	C (SGTS)	—
48	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.	E	—
49	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment overpressurization to failure.	E	—
50	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.	E	—
51	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.	D—See 41	—
52	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.	N/A	—
53	Not Used		None	—
54	Proceduralize alignment of spare diesel to shutdown board after Loss of Offsite Power and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.	C (with current swing diesel generator)	—
55	Not Used		None	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
56	Provide an additional diesel generator.	SAMA would increase the reliability and availability of onsite emergency AC power sources.	E	—
57	Provide additional DC battery capacity	SAMA would ensure longer batter capability during an SBO, reducing the frequency of long-term SBO sequences.	E	—
58	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO.	E	—
59	Procedure to cross-tie high pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high pressure core spray pumps.	N/A	—
60	Improve 4.16 kV bus cross-tie ability.	SAMA would improve AC power reliability.	None	2-11
61	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC buses, or installing a portable diesel-driven batter charger.	E	—
62	Increase/improve DC bus load shedding.	SAMA would extend battery life in an SBO event.	E	—
63	Replace existing batteries with more reliable ones.	SAMA would improve DC power reliability and thus increase available SBO recovery time.	N/A	—
63A	Mod for DC Bus A reliability	Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to offsite power, and defeats one half of the low vessel pressure permissive for LPCI/CS injection valves. SAMA would increase the reliability of AC power and injection capability.	C	(2-13)
64	Create AC power cross-tie capability with other unit.	SAMA would improve AC power reliability.	E	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
65	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus diesel generator, reliability.	C	—
66	Develop procedures to repair or replace failed 4 kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.	C	(2-9)
67	Emphasize steps in recovery of offsite power after an SBO.	SAMA would reduce human error probability during offsite power recovery.	C	—
68	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.	C	—
69	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.	C	—
70	Install gas turbine generator.	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.	E	—
71	Not Used		None	—
72	Create a back-up source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the diesel generators which would contribute to enhanced diesel reliability.	D—73	—
73	Use Fire Protection System as a back-up source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the diesel generators which would contribute to enhanced diesel reliability.	None	2-8
74	Provide a connection to an alternate source of offsite power.	SAMA would reduce the probability of a loss of offsite power event.	E	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
75	Bury offsite power lines.	SAMA could improve offsite power reliability, particularly during severe weather.	E	—
76	Replace anchor bolts on diesel generator oil cooler.	Millstone Nuclear Power Station 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. Note that these were Fairbanks Morse DGs.	D—See 114	—
77	Change Undervoltage (UV), Auxiliary Feedwater Actuation Signal (AFAS) Block and High Pressurizer Pressure Actuation Signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.	N/A	—
78	Provide DC power to the 120/240 V vital AC system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120 VAC Bus.	None	2-12
79	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.	N/A	—
80	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.	N/A	—
81	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.	N/A	—
82	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.	N/A	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
83	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.	N/A	—
84	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.	N/A	—
85	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.	N/A	—
86	Implement a maintenance practice that inspects 100% of the tubes in an SG.	SAMA would reduce the potential for an SGTR.	N/A	—
87	Locate RHR inside of containment.	SAMA would prevent ISLOCA out the RHR pathway.	A	—
88	Not Used.		None	—
89	Install additional instrumentation for ISLOCAs.	Pressure of leak monitoring instruments installed between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines would decrease ISLOCA frequency.	A	—
90	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.	A	—
91	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.	A	—
92	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.	A	—

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
93	Provide leak testing of valves in ISLOCA paths.	At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested. This SAMA would help reduce ISLOCA frequency.	A	—
94	Revise EOPs to improve ISLOCA identification.	Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment. Procedure enhancements would ensure LOCA outside containment could be identified as such.	A	—
95	Ensure all ISLOCA releases are scrubbed.	This SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would cover with water.	A	—
96	Add redundant and diverse limit switches to each containment isolation valve.	Enhanced isolation valve position indication could reduce the frequency of containment isolation failure and ISLOCAs.	A	—
97	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.	D—See 99	—
98	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.	D—See 99	—
99	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.	None	2-14

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
100	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating: a rupture in the RCP seal cooler of the component cooling system an ISLOCA in a shutdown cooling line, an AFW flood involving the need to remove a watertight door.	D—See 99	—
101	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.	C	—
102	Perform surveillances on manual valves used for back-up AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.	N/A	—
103	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.	N/A	—
104	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.	N/A	—
105	Proceduralize intermittent operation of HPCI.	SAMA would allow for extended duration of HPCI availability.	None	2-3

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
106	Increase the reliability of safety relief valves. (Adding signals to add electrical signal to open automatically).	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluates medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.	C	—
107	Install motor-driven feedwater pump.	This would increase the availability of injection subsequent to MSIV closure.	E	—
108	Procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.	C, IPE 1.4.1	—
109	Increase available NSPH for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.	C	—
110	Increase the SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after SLC injection.	E	—
111	Reduce DC dependency between high pressure injection system and ADS.	SAMA would ensure containment depressurization and high pressure injection upon a DC failure.	N/A	—
112	Modify RWCU for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.	C	(2-6)
113	Use of CRD for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.	C	(2-1)

Table 6. (Continued).

Phase I SAMA ID number	SAMA title	Description of potential enhancement	Screening criterion*	Phase II SAMA ID number**
114	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.	C	—
115	Allow cross connection of uninterruptable compressed air supply to opposite unit.	SAMA would increase the ability to depressurize containment using the hardened vent.	C	—

* N/A indicates that the proposed SAMA is not applicable to the Hatch BWR-4/Mark I design.
A indicates that the proposed SAMA is related to mitigation of an Intersystem LOCA (ISLOCA). Per IN-92-36, and its supplement, ISLOCA contributes little risk for boiling water reactors, because of the lower primary pressures. Because of the low risk contribution due to ISLOCA, this SAMA has not been developed further.
B indicates that the proposed SAMA is related to RCP seal leakage. A review of NUREG-1560 indicates that although RCP seal leakage is important for PWRs, recirculation pump leakage does not significantly contribute to CDF in BWRs.
C indicates that the proposed SAMA has already been installed at Hatch.
D indicates that similar item is addressed under other proposed SAMAs.
E indicates that SAMA did not pass initial screening to move into Phase II—no Phase II number assigned.

** ID numbers in parenthesis show SAMAs initially considered but dropped from Phase II analysis.

During the Level II analysis, it was determined that six of the SAMA candidates were adequately covered by existing plant design and procedures. In addition, the phase II costing for one of the candidates was found to be in excess of the $500,000 screening criterion. As a result, these six SAMA candidates [SAMA numbers (2-1, 2-4, 2-6, 2-9, 2-10, 2-13, and 2-16) in Table 6] were dropped from further consideration.

A description of each of the remaining nine evaluated SAMA candidates follows.

5.1 SAMA Candidate 2-2, Use Of Fire Protection System As A Backup Source For The Containment Spray System.

Description: Alternate water supplies from the Residual Heat Removal Service Water System (RHRSW) and from fire water to containment spray were added as redundant to the normal supply from RHR in the HNP model, as a result of this SAMA. The current base model does not credit possible cross-tie from either the RHRSW system or from the fire water system.

Cost: $25,000/unit　　Reduction in Risk Benefit: $0

Net Benefit: ($25,000/unit)

5.2 SAMA Candidate 2-3, Proceduralize Intermittent Operation of HPCI (High Pressure Coolant Injection)

HPCI is a standby system and this SAMA has no effect on initiating event frequencies. The intermittent operation of HPCI is already credited in the HNP PRA model by way of operator actions. As a result, there would be no change in the Large Early Release Frequency.

Cost: $22,200/unit　　Reduction in Risk Benefit: $0

Net Benefit: ($22,200/unit)

5.3 SAMA Candidate 2-5(A/B) Modifications to add Diesel Generator Room and Switchgear Room High Temperature Alarms or Redundant Louver/Thermostats

Emergency diesel generators are very important to LERF and improving diesel generator availability would have a significant impact on LERF. This SAMA would add redundant heat protection to the Diesel Generator Room and would be effective only if existing heat protection failed.

Cost: $100,000/unit　　Reduction in Risk Benefit: $2,492

Net Benefit: ($97,508/unit)

5.4 SAMA Candidate 2-7, Add Redundant DC Control Power for PSW Pumps

PSW supplies cooling water to several safety-related systems that are important to the mitigation of core melt progression. These include drywell cooling, control room HVAC, and decay heat removal. Improving the availability of PSW would reduce the large-early release frequency (LERF).

Cost: $97,000/unit　　Reduction in Risk Benefit: $500

Net Benefit: ($96,500/unit)

5.5 SAMA Candidate 2-8, Use Fire Protection as a Back-Up to Diesel Generator Cooling

This SAMA involves providing alternate cooling water to the emergency diesel generators from the fire protection system by connecting a hose from a fire hydrant to a supply header and another hose from the supply header to the affected diesel generator(s). Emergency diesel generators are important to CDF and improving diesel generator availability would reduce core damage frequency. In the case of the 1B diesel generator, an alternate supply from the standby service water system or from plant service water (depending on the initial alignment) is already available. This SAMA would add an additional source of potential cooling water should other sources fail.

Cost: $126,000/unit   Reduction in Risk Benefit: $2,098

Net Benefit: ($123,902/unit)

5.6 SAMA Candidate 2-11, Improve 4.16kV Bus Cross-Tie Ability

This SAMA involves supplying power to PSW pumps from an alternate source. The purpose is to ensure cooling water supply to the only available diesel generator, when the other two EDGs have failed. As the required conditions for this SAMA to be of benefit are low frequency, the benefit is small as well.

Cost: $100,000/unit   Reduction in Risk Benefit: $61

Net Benefit: ($99,939/unit)

5.7 SAMA Candidate 2-12, Provide Alternate DC Power to the 120/240 V Vital AC System

This SAMA involves providing DC power to the vital AC system from a station service battery instead of from the vital AC battery that currently supplies DC power. The supply from the battery is a third supply and is redundant to the supplies from two different power buses. The vital AC system supplies power for feedwater control and for bypass valve operation. The vital AC battery is not important to CDF and as a result, this SAMA has no impact.

Cost: $106,360/unit   Reduction in Risk Benefit: $78

Net Benefit: ($106,282/unit)

5.8 SAMA Candidate 2-14, Implement Internal Flood Identification and Mitigation Enhancements

This SAMA involves adding controls for the three fire pumps in the main control room and revising procedures to allow shutdown of the fire pumps, given a high level alarm in one or more of the reactor building drain sumps, after verifying that a fire does not exist. Reducing the frequency of the two flooding initiators will reduce the frequency of core damage. The two internal flooding initiating events in the baseline model do not contribute to LERF, so there is no impact on the frequency of large early release from changes in these initiating event frequencies.

Cost: $325,000/unit   Reduction in Risk Benefit: $98

Net Benefit: ($324,902/unit)

5.9 SAMA Candidate 2-15, Provide Reliable Power to Control Building Fans

This SAMA involves modifying the electric power supply to the switchgear room fans so that at least one supply fan and one exhaust fan for each unit are supplied by emergency power. None of the switchgear room HVAC fans are relied upon in the current HNP model. Therefore, there is no impact on core damage frequency or frequency of large early release, given the current models, from the changes described in this SAMA.

Cost: $202,000 for both units　　Reduction in Risk Benefit: $0

Net Benefit: ($101,000/unit)

A summary of the Phase II analyses is presented in Table 7.

Table 7. Summary of Phase II SAMA analyses.

SAMA ID number	Averted offsite exposure	Averted offsite costs	Averted onsite exposure	Averted onsite cleanup cost	Averted replacement power	Total benefits	Cost of implementation	Net value of modifications
2-2	$0	$0	$0	$0	$0	$0	$25,000/unit	($25,000/unit)
2-3	$0	$0	$0	$0	$0	$0	$22,200/unit	($22,200/unit)
2-5 (A/B)	$757	$1,110	$12	$379	$234	$2,492	$100,000/unit	($97,508/unit)
2-7	$74	$74	$7	$213	$132	$500	$97,000/unit	($96,500/unit)
2-8	$635	$915	$11	$331	$205	$2,098	$126,000/unit	($123,902/unit)
2-11	$25	$36	$0	$0	$0	$61	$100,000/unit	($99,939/unit)
2-12	$0	$0	$1	$47	$29	$78	$106,360/unit	($106,282/unit)
2-14	$0	$0	$2	$59	$37	$98	$325,000/unit	($324,902/unit)
2-15	$0	$0	$0	$0	$0	$0	$202,000 both units	($101,000/unit)

6.0 Conclusions

None of the SAMAs analyzed would be being justified on a cost-benefit basis. The area surrounding HNP is predominantly agricultural and forested land with sparse population. As a result, the baseline risk of the plant is low both for population doses and economic risk. This limits the potential averted risk from any severe accident modifications. As the analysis shows, none of the analyzed modifications would provide more benefit than they would cost.

REFERENCES

1. Chanin, D. and Young, M., Code Manual for MACCS2: Volume 1, User's-Guide, SAND 97-0594, 1997.
2. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U. S. Nuclear Regulatory Commission, Washington, D.C., June 1989.
3. Edwin I. Hatch Nuclear Power Plant Site Evacuation Plan, Revision 1.5, August 1996.
4. NUREG/CR-6525, "SECPOP90: Sector Population, Land Fraction, and Economic Estimation Program," U.S. Nuclear Regulatory Commission, Washington, D.C., September 1997.
5. U.S. Department of Agriculture, "1997 Census of Agriculture," National Agricultural Statistics Service, 1998.
6. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Calvert Cliffs Nuclear Power Plant," Supplement 1, U.S. Nuclear Regulatory Commission, Washington, D.C., February 1999.
7. John E. Till and H. Robert Meyer, Radiological Assessment, A Textbook on Environmental Dose Analysis, NUREG/CR-3332, ORNL-5968, p.2-23, September 1983, prepared for USNRC, Washington, D.C.).
8. U.S. Nuclear Regulatory Commission, "Regulatory Analysis Technical Evaluation Handbook," NUREG/BR-0184, 1997.

Appendix E

TECHNICAL SPECIFICATION CHANGES

CONTENTS

E.1 PROPOSED CHANGES

E.1.1 DESCRIPTION OF CHANGES

As part of the license renewal application development process for Plant Hatch, Southern Nuclear Operating Company (SNC) proposes to revise the Plant Hatch Unit 1 and Unit 2 Technical Specifications requirements for reactor vessel pressure and temperature (P/T) limits. In evaluating the reactor pressure vessel (for both Hatch 1 and 2) for the license renewal term, the effects of irradiation on the core beltline region have been analyzed to determine the impact of the extended operating period on the pressure-temperature operating limits, as required by 10CFR50, Appendix G.

The evaluation (incorporating Extended Power Uprate at 17 Effective Full Power Years (EFPY)) has been performed for a lifetime of 54 EFPY for both Units. This input was used to generate pressure-temperature curves for 54 EFPY for both Units. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been developed, due to the expected irradiation shift for the Hatch 1 vessel.

In support of the proposed changes, General Electric (GE) has prepared and issued GE-NE-B1100827-00-01, "Plant Hatch Units 1 & 2, RPV Pressure Temperature Limits License Renewal Evaluation," which is provided as Enclosure 3.

E.1.2 PROPOSED CHANGES TO FIGURES 3.4.9-1, 3.4.9-2, AND 3.4.9-3 OF HATCH UNIT 1 AND 2 TECHNICAL SPECIFICATIONS

The proposed change replaces the current P-T curves with new curves generated as part of GE's evaluation contained in GE-NE-B1100827-00-01. The evaluation provides for a lifetime of 54 Effective Full Power Years for both Units, which encompasses the 60-year renewed operating license term. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been provided, due to the expected irradiation shift for the Hatch 1 vessel. The existing 20 and 24 year curves for RPV inservice hydrostatic and inservice leakage tests are retained for Unit 1.

E.1.3 JUSTIFICATION FOR CHANGES

One of the major considerations for extended life of the reactor pressure vessel is irradiation of the core region, or beltline. The effect of irradiation is to shift the reference nil-ductility transition temperature (RT_{NDT}) of the beltline materials. This shift must be evaluated in order to conform to the requirements of 10 CFR 50, Appendix G. To encompass the effects of irradiation for the license renewal term, a maximum lifetime of 54 EFPY was used to determine the effects of irradiation and to develop the P-T curves.

GE has evaluated the effect of an additional twenty years of operation on the P-T limits in the above referenced report. New curves have been generated, incorporating the effects of the renewal term into the existing curves which already consider the effects of extended power uprate. P-T curves were developed for three reactor conditions: pressure test, non-nuclear heatup and cooldown, and core critical operation. The new curves ensure that vessel P-T limits are not exceeded during all phases of operation for the renewal period. There are no proposed changes to the Limiting Condition for Operation or to any of the surveillances of specification 3.4.9. All the curves were generated based on the approved methodologies of 10 CFR 50 Appendix G.

This Page Intentionally Left Blank.

Enclosure 1

Edwin I. Hatch Nuclear Plant
Request to Revise Technical Specifications:
Pressure and Temperature Limits

Page Change Instructions

Unit 1

Page	Instruction
3.4-25	Replace
3.4-26	Replace
3.4-27	Replace

Unit 2

Page	Instruction
3.4-25	Replace
3.4-26	Replace
3.4-27	Replace

Enclosure 2

Proposed Changes to Units 1 and 2 Technical Specification
Figures 3.4.9-1, 3.4.9-2, and 3.4.9-3

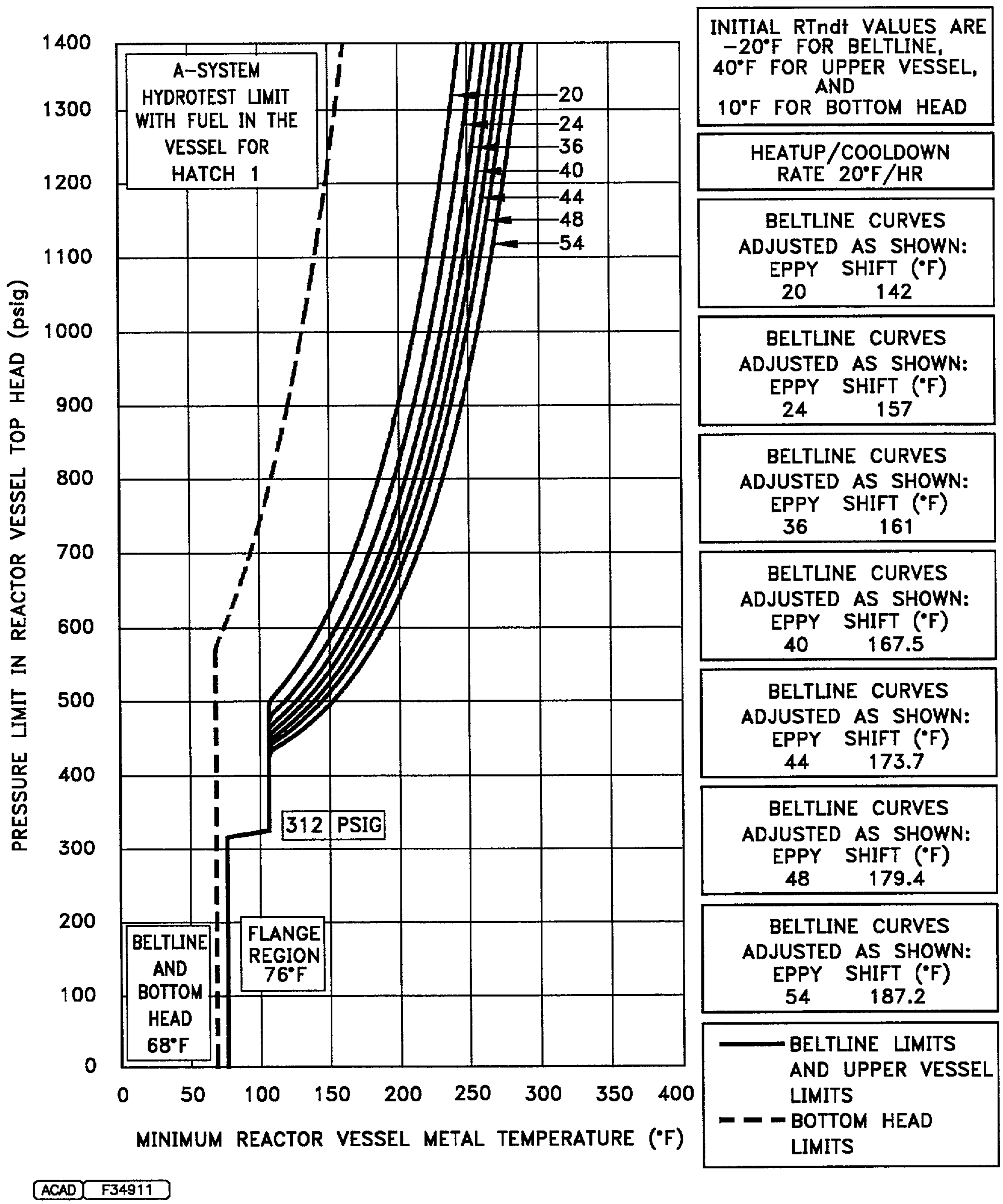


Figure 3.4.9−1 (Page 1 of 1)
Pressure/Temperature Limits for
Inservice Hydrostatic and Inservice Leakage Tests

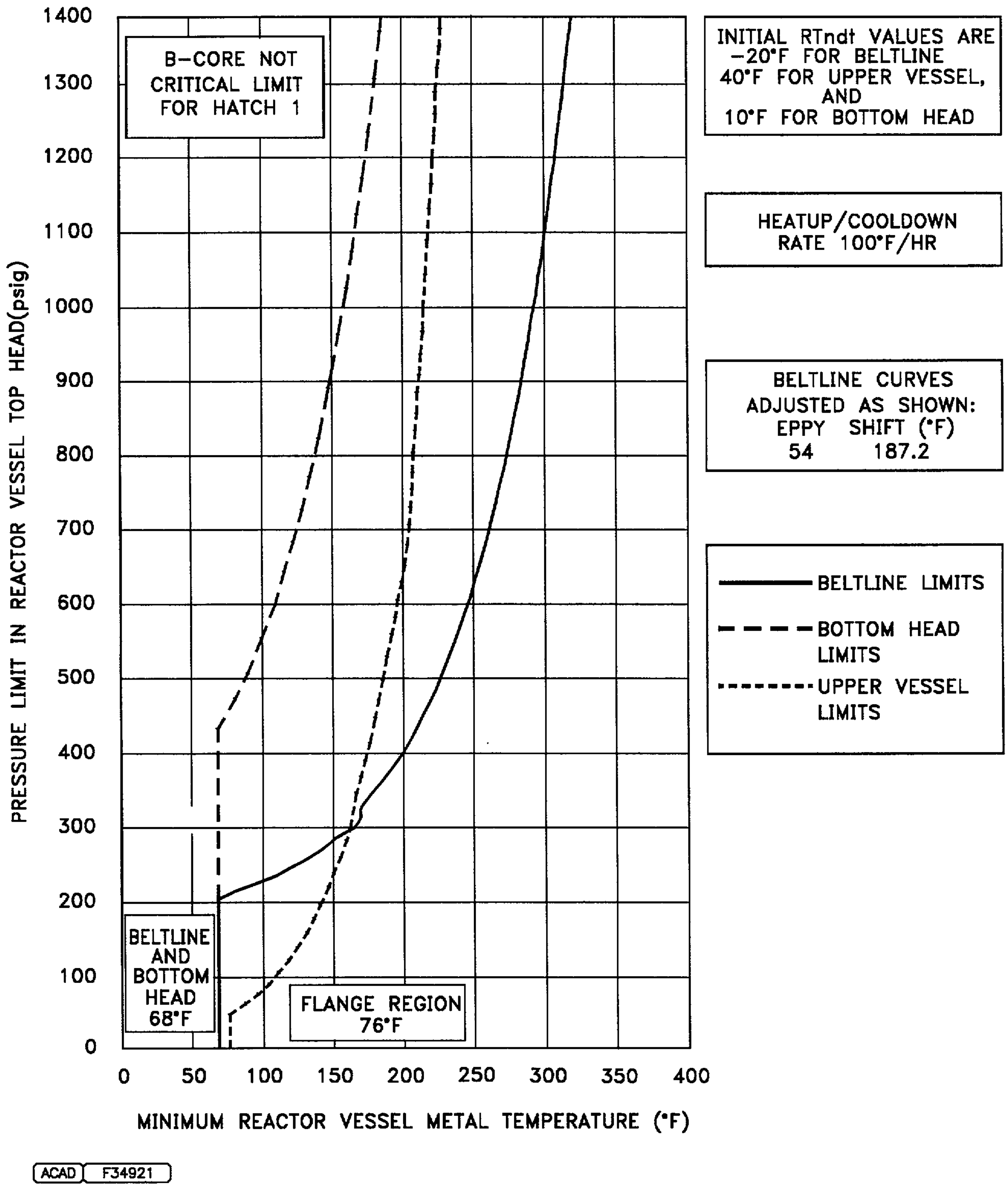


Figure 3.4.9-2 (Page 1 of 1)
Pressure/Temperature Limits for Non-Nuclear Heatup,
Low Power Physics Tests, and Cooldown following a shutdown

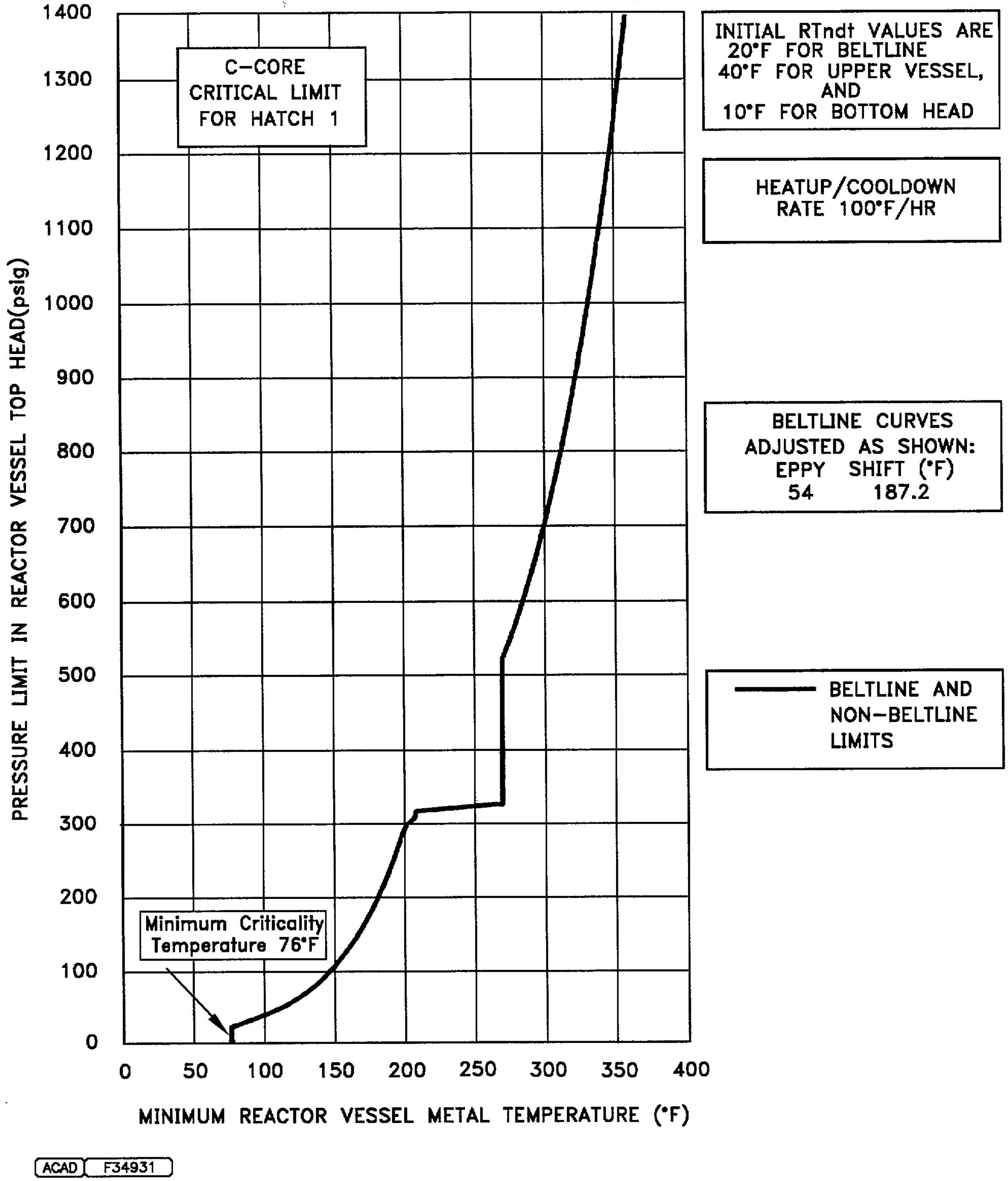


Figure 3.4.9-3 (Page 1 of 1)
Pressure/Temperature Limits for Criticality

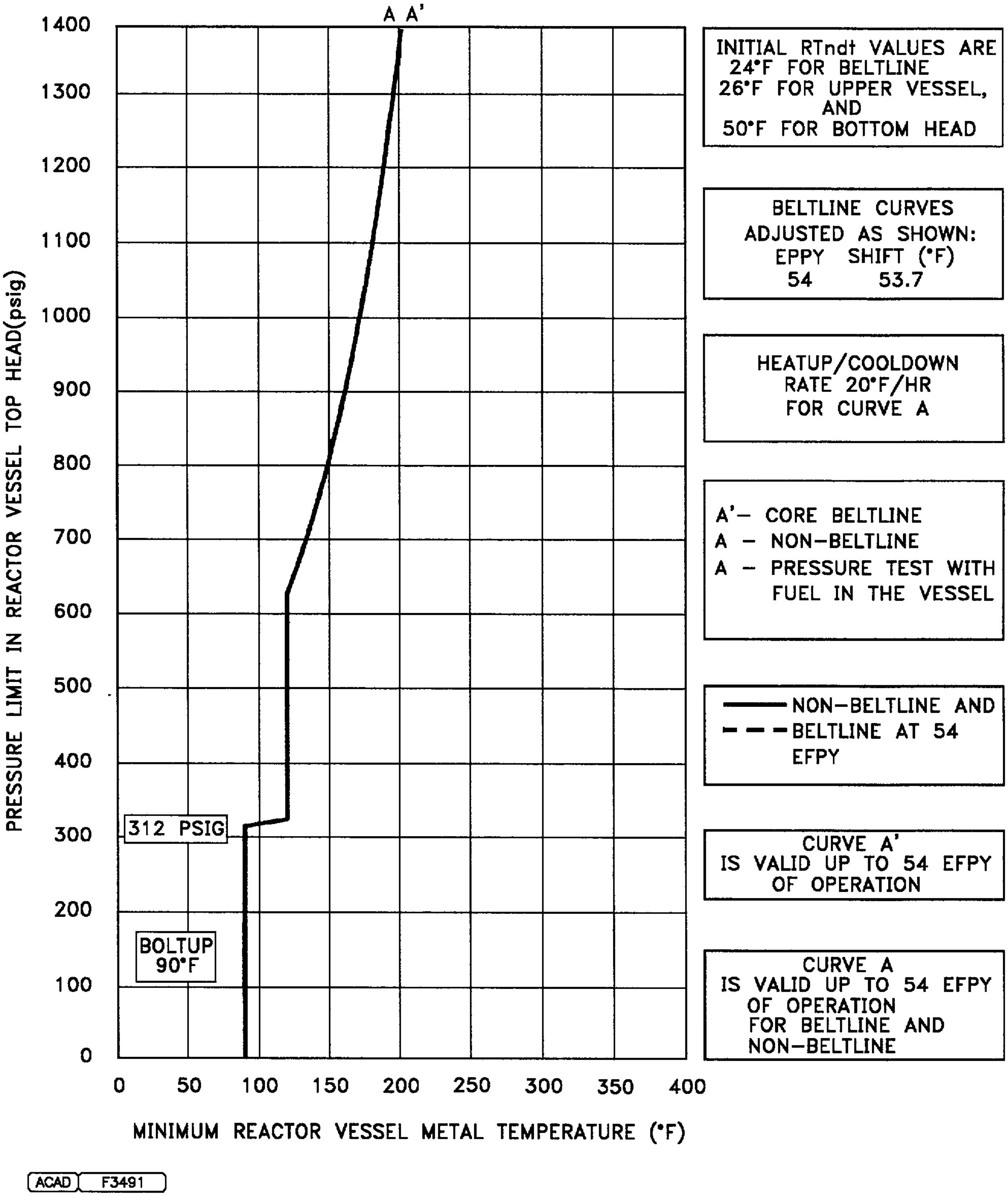


Figure 3.4.9–1 (Page 1 of 1)
Pressure/Temperature Limits for
Inservice Hydrostatic and Inservice Leakage Tests

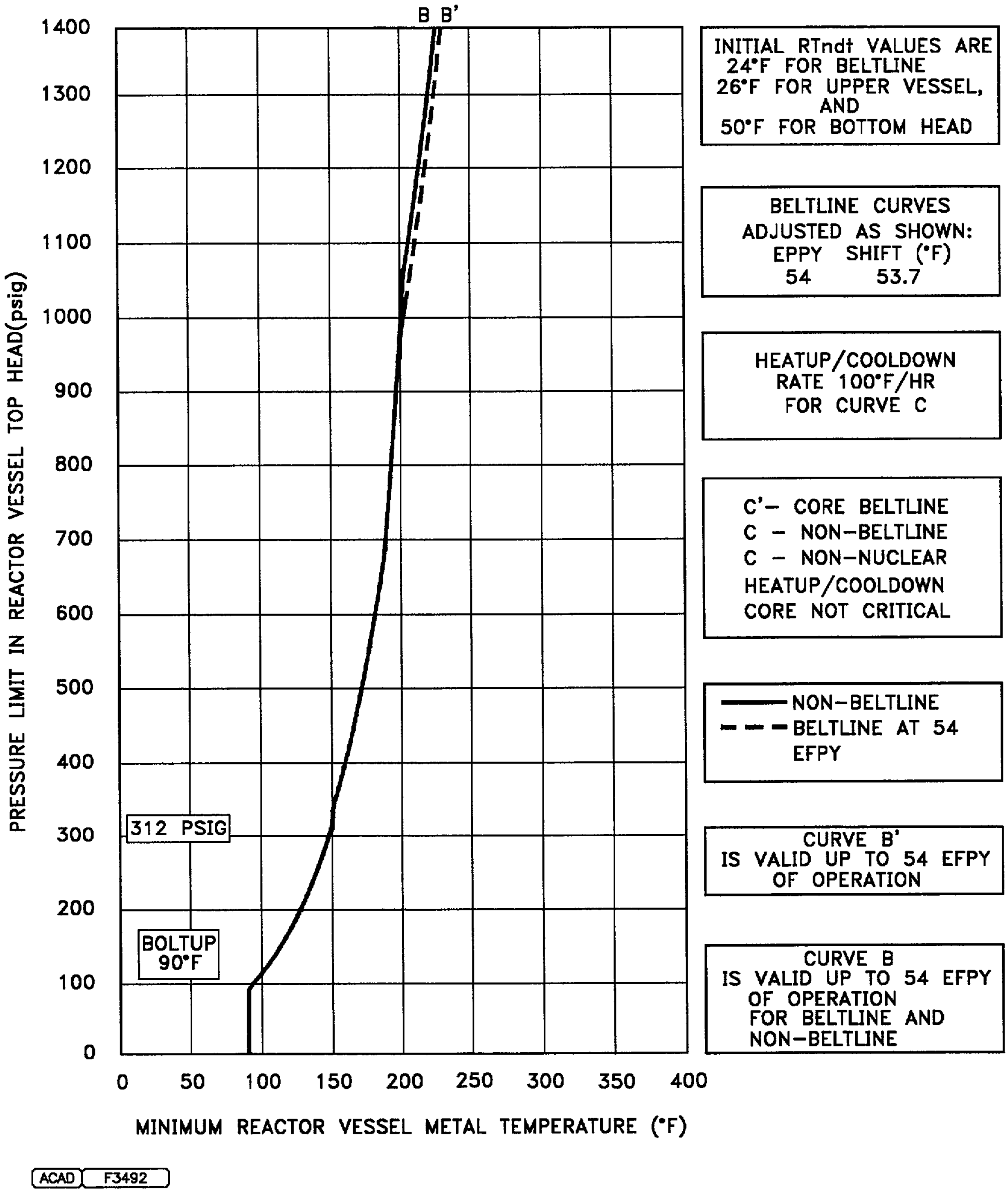


Figure 3.4.9–2 (Page 1 of 1)
Pressure/Temperature Limits for Non–Nuclear Heatup,
Low Power Physics Tests, and Cooldown following a shutdown

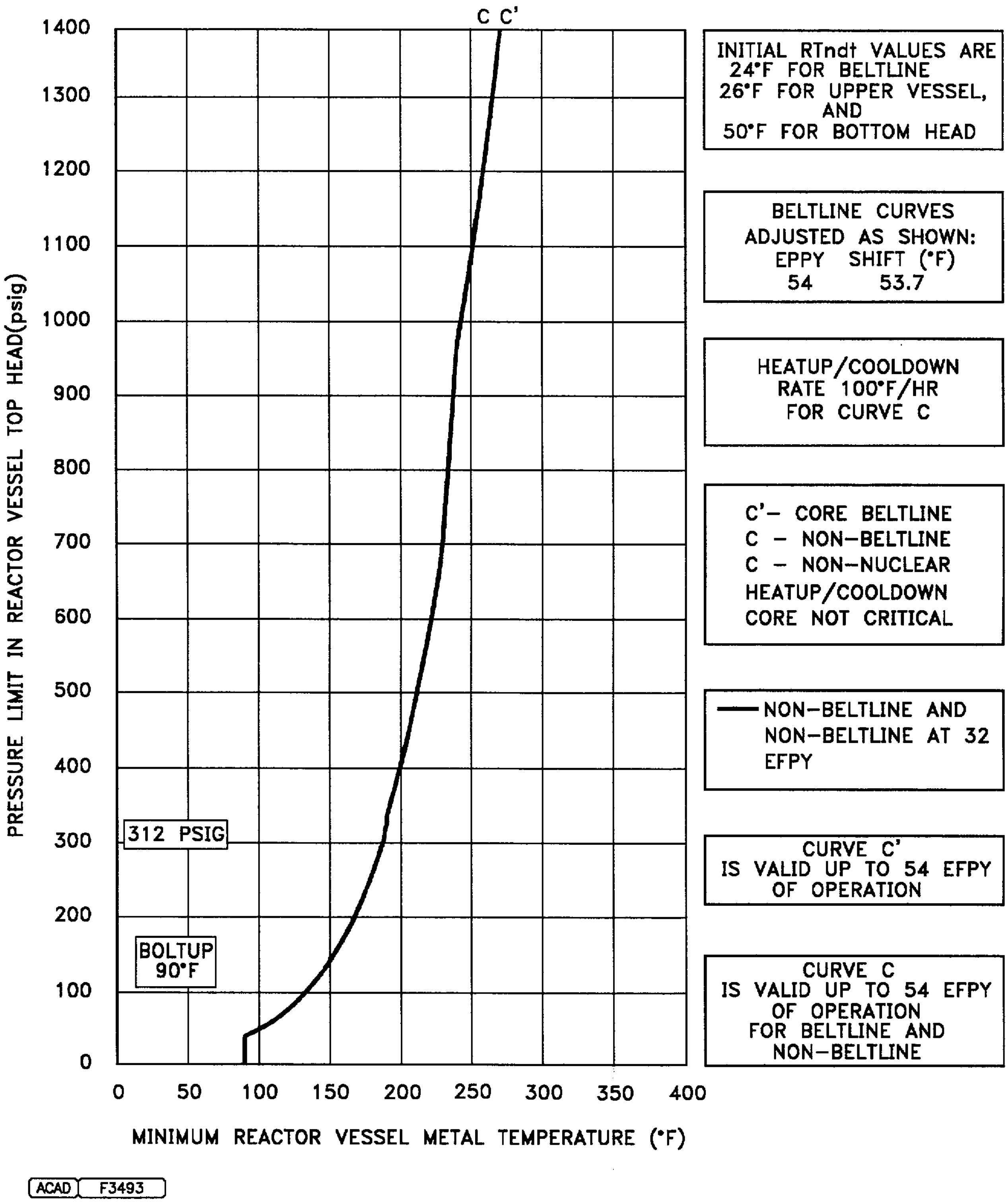


Figure 3.4.9–3 (Page 1 of 1)
Pressure/Temperature Limits for Criticality

Enclosure 3

Plant E. I. Hatch Units 1 and 2

RPV Pressure Temperature Limits
License Renewal Evaluation
GE – NE – B1100827 – 00 – 01

GE Nuclear Energy

Structural Assessment and Mitigation
General Electric Company
175 Curtner Avenue, San Jose, CA 95125

GE-NE-B1100827-00-01
Class II

March 1999

PLANT HATCH UNITS 1 & 2
RPV PRESSURE TEMPERATURE LIMITS
LICENSE RENEWAL EVALUATION

Prepared by: T A Caine for
L. Schultz, Engineering Intern
Structural Assessment and Mitigation

Prepared by: BD Frew
B. D. Frew, Senior Engineer
Structural Assessment and Mitigation

Verified by: [illegible]
L. J. Tilly, Senior Engineer
Structural Assessment and Mitigation

Approved by: T A Caine
T. A. Caine, Manager
Structural Assessment and Mitigation

**IMPORTANT NOTICE REGARDING
CONTENTS OF THIS REPORT
PLEASE READ CAREFULLY**

This report was prepared by General Electric solely for the use of Southern Nuclear Operating Company. The information contained in this report is believed by General Electric to be an accurate and true representation of the facts known, obtained, or provided to General Electric at the time this report was prepared.

The only undertakings of the General Electric Company respecting information in this document are contained in the contract between the customer and General Electric Company, as identified in the purchase order for this report and nothing contained in this document shall be construed as changing the contract. The use of this information by anyone other than the customer or for any purpose other than that for which it is intended, is not authorized; and with respect to any unauthorized use, General Electric Company makes no representation or warranty, and assumes no liability as to the completeness, accuracy, or usefulness of the information contained in this document.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

ABSTRACT

As part of the effort to evaluate the reactor pressure vessel (for both Hatch 1 and 2) for the license renewal term, the effects of irradiation on the core beltline region have been evaluated. The purpose of this evaluation was to provide input to the pressure-temperature operating limits, as required by 10CFR50, Appendix G [1].

The evaluation (incorporating Extended Power Uprate at 17 Effective Full Power Years (EFPY) [2]) has been performed for a lifetime of 54 EFPY for both Units. This input was used to generate pressure-temperature curves for 54 EFPY for both Units. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been provided, due to the expected irradiation shift for the Hatch 1 vessel.

1. INTRODUCTION

One of the major considerations for extended life of the Reactor Pressure Vessel is irradiation of the core region, or beltline. The effect of irradiation is to shift the reference nil-ductility transition temperature (RT_{NDT}) of the beltline materials. This shift must be evaluated in order to conform to the requirements of 10CFR50, Appendix G [1]. To encompass the effects of irradiation for the license renewal term, a maximum lifetime of 54 EFPY was used to determine the effects of irradiation (see Section 3), and to develop the pressure-temperature (P-T) curves (Section 4).

The (P-T) curves included in this report have been developed to present steam dome pressure versus minimum vessel metal temperature incorporating appropriate non-beltline limits and irradiation embrittlement effects in the beltline. Complete P-T curves were developed for 54 effective full power years (EFPY) for both Hatch 1 and 2; in addition, intermediate P-T curves for Hatch Unit 1 have been included for 36, 40, 44 and 48 EFPY, due to the expected irradiation shift for the Hatch 1 vessel. The methodology used to generate the P-T curves in this report is the same as the methodology used to generate the P-T curves for extended power uprate [2]. The pressure-temperature (P-T) curves are established to the requirements of 10CFR50, Appendix G [1] to assure that brittle fracture of the reactor vessel is prevented. The method used to account for irradiation embrittlement is described in Regulatory Guide 1.99, Revision 2 [3], or Rev 2.

In addition to beltline considerations, there are non-beltline discontinuity limits such as nozzles, penetrations, and flanges which affect the P-T curves. The non-beltline limits are based on generic analyses which are adjusted to the maximum reference temperature of nil ductility transition (RT_{NDT}) for the applicable Hatch 1 or 2 vessel components. The non-beltline limits are also governed by requirements in [1].

Furthermore, curves are included to allow monitoring of the bottom head regions of the vessel separate from the beltline region and upper vessel. This refinement could minimize heating requirements prior to pressure testing.

2. RESULTS AND CONCLUSIONS

Based on the results of the evaluation, the following results and conclusions were determined:

- For Unit 1, the 54 EFPY RPV peak fluence prediction is 3.47×10^{18} n/cm^2 at the vessel wall, based on extended power uprate. The 54 EFPY fluence prediction is 2.51×10^{18} n/cm^2 at 1/4 T. (See Section 3). For Unit 2, the 54 EFPY RPV peak fluence prediction is 3.82×10^{18} n/cm^2 at the vessel wall, based on extended power uprate. The 54 EFPY fluence prediction is 2.77×10^{18} n/cm^2 at 1/4 T. (See Section 3)

- The adjusted reference temperature (ART = Initial RT_{NDT} + ΔRT_{NDT} + Margin) was predicted for each beltline material, based on the methods of Regulatory Guide 1.99, Rev 2. The ART for the limiting material for Unit 1, Plate G-4804-2, Heat C4114-2, at 54 EFPY is 167.2°F. For Unit 2, the limiting ART at 54 EFPY is 77.7°F (Plate G-6603-2, Heat C8553-1). Both plates are lower than the 200°F requirement of 10CFR50 Appendix G [1] and Rev 2 [3].

- An update of the beltline material USE values at 54 EFPY was performed using the Reg. Guide 1.99, Rev. 2 methodology. The Equivalent Margin Analyses demonstrate that the 10CFR50 Appendix G [1] safety requirements are met.

- P-T curves were developed for three reactor conditions: pressure test (Curve A), non-nuclear heatup and cooldown (Curve B), and core critical operation (Curve C) which are valid for up to 54 EFPY of operation. For Unit 1, the beltline curve is more limiting for Curve A at pressures above approximately 410 psig. For Curves B and C, the beltline curves are limiting for pressures above approximately 300 psig. The P-T curves for 54 EFPY are shown in Figures 4-1 through 4-3 [The intermediate curves for 36, 40, 44, and 48 EFPY are located in Appendices A-D]. For Unit 2, the bottom head curve is more limiting for Curve A at pressures above approximately 610 psig. For Curve B, the Feedwater nozzle limits are applicable in the range 90-960 psig. For Curves B and C, the beltline curves are limiting for pressures above approximately 960 psig. The P-T curves for 54 EFPY are shown in Figures 4-4 through 4-6.

3. ADJUSTED REFERENCE TEMPERATURE AND UPPER SHELF ENERGY

The 54 EFPY peak fluence values of 3.47×10^{18} n/cm^2 and 3.82×10^{18} n/cm^2 for Hatch Unit 1 and Hatch Unit 2, respectively, are used to calculate the 54 EFPY 1/4T fluence values of 2.51×10^{18} n/cm^2 and 2.77×10^{18} n/cm^2 (Tables 3-1 and 3-2, for Units 1 and 2, respectively). The 54 EFPY 1/4T fluence is used in this section to calculate adjusted reference temperatures (ARTs) and upper shelf energy (USE) decrease for the beltline materials.

3.1 ADJUSTED REFERENCE TEMPERATURE AT 54 EFPY

The effect on adjusted reference temperature (ART) due to irradiation in the beltline materials is determined according to the methods in Reg. Guide 1.99, Rev. 2 [3], as a function of neutron fluence and the element contents of copper (Cu) and nickel (Ni). The specific relationship from Reg. Guide 1.99, Rev. 2 [3] is:

$$ART = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin} \qquad (3\text{-}1)$$

where:

$$\Delta RT_{NDT} = CF \cdot f^{\,(0.28-0.10\log f)} \qquad (3\text{-}2)$$

$$\text{Margin} = 2\sqrt{\sigma_I^2 + \sigma_\Delta^2} \qquad (3\text{-}3)$$

CF = chemistry factor from Table 1 or Table 2 of Reg. Guide 1.99, Rev. 2 [3]

f = 1/4T fluence (n/cm^2) divided by 10^{19}

σ_I = standard deviation on initial RT_{NDT} which is taken to be 0°F

σ_Δ = standard deviation on ΔRT_{NDT}, 28°F for welds and 17°F for base material, except that σ_Δ need not exceed 0.50 times the ΔRT_{NDT} value

The ART values for 54 EFPY are calculated based upon chemistry data as described in Table 3-1 and 3-2 for Hatch Unit 1 and Hatch Unit 2, respectively.

3.2 ART VS. EFPY

Each beltline plate and weld ΔRT_{NDT} value is determined by multiplying the CF from Reg. Guide 1.99, Rev. 2 [3] determined for the Cu-Ni content of the material, by the fluence factor for the EFPY being evaluated. The Initial RT_{NDT}, ΔRT_{NDT} and Margin are added to get the ART of the material. The 54 EFPY ART values for all of the beltline plates and welds are shown in Tables 3-1 and 3-2. The ART for the limiting beltline material in Hatch Unit 1, plate Heat C4114-2, at 54 EFPY is 167.2°F. The ART for the limiting beltline material in Hatch Unit 2, plate Heat C8553-1, at 54 EFPY is 77.7°F.

3.3 UPPER SHELF ENERGY AT 54 EFPY

Unirradiated Upper Shelf data were not available for all of the material heats. Due to the lack of specific pre-operational USE data, Hatch 1 and 2 have been evaluated to verify that the BWR Owners' Group Equivalent Margin Analyses are applicable. The calculations in Tables 3-3 through 3-6 show that the equivalent margin analyses are applicable. The Equivalent Margin Analyses demonstrate that the 10 CFR 50, Appendix G safety requirements are satisfactorily met for Hatch Units 1 and 2. The Owners' Group Program Report [4] was submitted to the NRC in December 1993 and approved by SER on December 8, 1993.

BELTLINE ART VALUES FOR Hatch 1

Lower-Intermediate
Thickness = 5.38 inches

Lower
Weld Thickness = 5.38 inches (Girth)
Plate Thickness = 6.375 inches (and Long Weld)

Lower-Intermediate
54 EFPY Peak I.D. fluence = 3.47E+18 n/cm^2
54 EFPY Peak 1/4 T fluence = 2.51E+18 n/cm^2

Lower
54 EFPY Peak I.D. fluence = 2.36E+18 n/cm^2
54 EFPY Peak 1/4 T weld fluence = 1.71E+18 n/cm^2
54 EFPY Peak 1/4 T plate fluence = 1.61E+18 n/cm^2

COMPONENT	HEAT OR HEAT/LOT	%Cu	%Ni	CF	Fluence Level n/cm^2	Initial RTndt °F	54 EFPY Δ RTndt °F	σ_I	σ_Δ	Margin °F	54 EFPY Shift °F	54 EFPY ART °F
PLATES:												
Lower												
G-4805-1	C4112-1	0.13	0.64	92	1.61E+18	8	47.7	0.0	17.0	34.0	81.7	89.7
G-4805-2	C4112-2	0.13	0.64	92	1.61E+18	10	47.7	0.0	17.0	34.0	81.7	91.7
G-4805-3	C4149-1	0.14	0.57	99	1.61E+18	-10	51.4	0.0	17.0	34.0	85.4	75.4
Lower-Intmed												
G-4803-7	C4337-1	0.17	0.62	128	2.51E+18	-20	80.0	0.0	17.0	34.0	114.0	94.0
G-4804-1	C3985-2	0.13	0.58	90	2.51E+18	-20	56.3	0.0	17.0	34.0	90.3	70.3
G-4804-2*	C4114-2	0.13	0.70	245	2.51E+18	-20	153.2	0.0	17.0	34.0	187.2	167.2
WELDS:												
Lower Long												
1-307	13253/1092 Flux 3791	0.221	0.732	189	1.61E+18	-50	98.0	0.0	28.0	56.0	154.0	104.0
Lower-Intmed Long.												
1-308	IP2809/1092 Flux 3854	0.22	0.735	189	2.51E+18	-50	118.2	0.0	28.0	56.0	174.2	124.2
1-308	IP2815/1092 Flux 3854	0.316	0.724	219	2.51E+18	-50	136.9	0.0	28.0	56.0	192.9	142.9
Girth												
Lower to Lower-Int Girth												
1-313	90099/0091 Flux 3977	0.197	0.060	91	1.71E+18	-10	48.5	0.0	24.2	48.5	96.9	86.9
1-313	33A277/0091 Flux 3977	0.258	0.165	126	1.71E+18	-50	67.1	0.0	28.0	56.0	123.1	73.1

* CF Adjusted by a factor of 2.62

Table 3-1: Hatch 1 ART Values (54 EFPY)

BELTLINE ART VALUES FOR Hatch 2

Lower-Intermediate
Thickness = 5.38 inches

Lower-Intermediate
54 EFPY Peak I.D. fluence = 3.82E+18 n/cm^2
54 EFPY Peak 1/4 T fluence = 2.77E+18 n/cm^2

Lower
Weld Thickness = 5.38 inches (Girth)
Plate Thickness = 6.375 inches (and Long Weld)

Lower
54 EFPY Peak I.D. fluence = 2.44E+18 n/cm^2
54 EFPY Peak 1/4 T weld fluence = 1.77E+18 n/cm^2
54 EFPY Peak 1/4 T plate fluence = 1.67E+18 n/cm^2

COMPONENT	HEAT OR HEAT/LOT	%Cu	%Ni	CF	Fluence Level n/cm^2	Initial RTndt °F	54 EFPY Δ RTndt °F	σ_I	σ_Δ	Margin °F	54 EFPY Shift °F	54 EFPY ART °F
PLATES:												
Lower												
G-6603-1	C8553-2	0.08	0.58	51	1.67E+18	-20	26.9	0.0	13.4	26.9	53.7	33.7
G-6603-2	C8553-1	0.08	0.58	51	1.67E+18	24	26.9	0.0	13.4	26.9	53.7	77.7
G-6603-3	C8571-1	0.08	0.53	51	1.67E+18	0	26.9	0.0	13.4	26.9	53.7	53.7
Lower-Intmed												
G-6602-2	C8554-1	0.08	0.57	51	2.77E+18	-20	33.1	0.0	16.6	33.1	66.2	46.2
G-6602-1	C8554-2	0.08	0.58	51	2.77E+18	-10	33.1	0.0	16.6	33.1	66.2	56.2
G-6601-4	C8579-2	0.11	0.48	73	2.77E+18	-4	47.4	0.0	17.0	34.0	81.4	77.4
WELDS:												
Lower Long 101-842	10137, LINDE 0091	0.216	0.043	98	1.67E+18	-50	51.6	0.0	25.8	51.6	103.3	53.3
Lower-Intmed Long. 101-834	51874, LINDE 0091 / Flux Lot 3458	0.147	0.037	68	2.77E+18	-50	44.2	0.0	22.1	44.2	88.3	38.3
Girth Lower to Lower-Int Girth 301-871	4P6052, LINDE 0091 / Flux Lot 0145	0.047	0.049	31	1.77E+18	-50	16.8	0.0	8.4	16.8	33.5	-16.5

Table 3-2: Hatch 2 ART Values (54 EFPY)

Table 3-3: Hatch 1 Plate Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM

FOR HATCH UNIT 1 - BWR 4/MK I - Including Extended Power Uprate

BWR/3-6 PLATE

Surveillance Plate USE:

%Cu = 0.12

1st Capsule Fluence = 2.4×10^{17} n/cm^2

2nd Capsule Fluence = 4.6×10^{17} n/cm^2

Unirradiated to 1st Capsule Measured % Decrease = 4 (Charpy Curves)

Unirradiated to 2nd Capsule Measured % Decrease = -5 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 9 (Rev 2, Figure 2)

2nd Rev 2 Predicted % Decrease = 10 (Rev 2, Figure 2)

Limiting Beltline Plate USE:

%Cu = 0.17

54 EFPY ¼ T Fluence = 2.51×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 19 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

19 % ≤ 21%, so vessel plates are bounded by equivalent margin analysis

Table 3-4: Hatch 1 Weld Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM

FOR HATCH UNIT 1 - BWR 4/MK I - Including Extended Power Uprate

BWR/2-6 WELD

Surveillance Weld USE:

%Cu = 0.30

1st Capsule Fluence = 2.4×10^{17} n/cm^2
2nd Capsule Fluence = 4.6×10^{17} n/cm^2

Unirradiated to 1st or 2nd Capsule Measured % Decrease = Unknown
1st to 2nd Capsule Measured % Decrease = -16 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 19 (Rev 2, Figure 2)
2nd Rev 2 Predicted % Decrease = 22 (Rev 2, Figure 2)

Limiting Beltline Weld USE:

%Cu = 0.316

54 EFPY ¼ T Fluence = 2.51×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 33 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

33 % ≤ 34%, so vessel welds are bounded by equivalent margin analysis

Table 3-5: Hatch 2 Plate Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM

FOR HATCH UNIT 2 - BWR 4/MK I - Including Extended Power Uprate

BWR/3-6 PLATE

Surveillance Plate USE:

%Cu = 0.08

1st Capsule Fluence = 2.3×10^{17} n/cm^2

Measured % Decrease = 0 (Charpy Curves)

Reg. Guide Rev 2 Predicted % Decrease = 7 (Rev 2, Figure 2)

Limiting Beltline Plate USE:

%Cu = 0.11

54 EFPY ¼ T Fluence = 2.77×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 15 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

15 % $\leq$ 21%, so vessel plates are bounded by equivalent margin analysis

Table 3-6: Hatch 2 Weld Equivalent Margin Analysis

PLANT APPLICABILITY VERIFICATION FORM
FOR HATCH UNIT 2 - BWR 4/MK I - Including Extended Power Uprate

BWR/2-6 WELD

Surveillance Weld USE:

%Cu = 0.13

Capsule Fluence = 2.3×10^{17} n/cm^2

Capsule Measured % Decrease = -1 (Charpy Curves)

Rev 2 Predicted % Decrease = 11 (Rev 2, Figure 2)

Limiting Beltline Weld USE:

%Cu = 0.216

54 EFPY ¼ T Fluence = 1.77×10^{18} n/cm^2

Rev 2 Predicted % Decrease = 24 (Rev 2, Figure 2)

Adjusted % Decrease = N/A (Rev 2, Position 2.2)

24 % ≤ 34%, so vessel welds are bounded by equivalent margin analysis

4. PRESSURE-TEMPERATURE CURVES

4.1 BACKGROUND

Nuclear Regulatory Commission (NRC) 10CFR50 Appendix G [1] specifies fracture toughness requirements to provide adequate margins of safety during the operating conditions to which a pressure-retaining component may be subjected over its service lifetime. The ASME Code (Appendix G of Section XI [8]) forms the basis for the requirements of 10CFR50 Appendix G. The limits for pressure and temperature are required by 10CFR50 Appendix G for three categories of operation: (a) hydrostatic pressure tests and leak tests, (b) core not critical heatup/cooldown, and (c) core critical operation. The heat transfer characteristics for these three categories are: (a) isothermal conditions for the hydrotest, and (b and c) insulated outside surface and metal temperature equaling the fluid temperature for 100°F/hr heatup/cooldown thermal rate. Heat transfer characteristics for the other transient conditions were based on flow and temperature conditions in the thermal cycle diagrams. The condition that results in the highest required temperature for the limiting material determines the minimum allowable temperature for the vessel.

There are four vessel regions defined in the thermal cycle diagram that should be monitored against the Pressure-Temperature (P-T) curve operating limits:

- Closure flange region (Region A)
- Core beltline region (Region B)
- Upper vessel (Regions A & B)
- Lower vessel (Regions B & C)

The closure flange region includes the bolts, top head flange, vessel flange, and adjacent plates and welds. The core beltline is the vessel location adjacent to the active fuel, such that the neutron fluence is sufficient to cause a significant shift of RT_{NDT}. The remaining portion of the vessel (i.e., upper vessel, lower vessel) includes shells, components like the nozzles, the support skirt, and stabilizer brackets; these regions will be called the non-beltline region.

Under certain conditions, the minimum bottom head temperature can be significantly cooler than the beltline or closure flange region. These conditions can occur when the recirculation pumps are operating at low speed (or are off), and during water injection through the control rod drives. To account for these circumstances, individual temperature limits for the bottom head were established. Bottom head curves are not provided for the core critical curve, since during core critical operation the entire RPV follows the steam saturation curve that is well to the right of the core critical curve.

The P-T curves for the heatup and cooldown operating condition at a given EFPY apply for both the 1/4T and 3/4T locations. When combining pressure and thermal stresses, it is usually necessary to evaluate stresses at the 1/4T location (inside surface flaw) and the 3/4T location (outside surface flaw). This is because the thermal gradient tensile stress of interest is in the inner wall during cooldown and is in the outer wall during heatup. However, as a conservative simplification, the thermal gradient stress at 1/4T is assumed to be tensile for both heatup and cooldown. This results in the approach of applying the maximum tensile stress at the 1/4T location. This approach is conservative for two reasons: 1) the maximum stress is used regardless of flaw location, and 2) the irradiation effects cause the allowable toughness, K_{IR}, at 1/4T to be less than that at 3/4T for a given metal temperature. This approach causes no operational difficulties, since the BWR vessel metal temperature is at steam saturation conditions during normal operation, satisfying the heatup/cooldown curve limits.

Except for the independent bottom head curve, the applicable temperature is the greater of the 10CFR50 Appendix G minimum temperature requirement and the ASME Appendix G limits. A summary of the requirements is provided in Table 4-1.

There are three vessel regions that affect the operating limits: the non-beltline regions, the core beltline region, and the closure flange. The closure flange region limits are controlling at lower pressures primarily because of

10CFR50, Appendix G requirements as indicated in Table 4-1. The non-beltline and beltline region operating limits are evaluated according to procedures in 10CFR50, Appendix G [1], ASME Boiler and Pressure Vessel Code, Section XI, Appendix G [8], and Welding Research Council (WRC) Bulletin 175 [5]. The beltline region minimum temperature limits are adjusted to account for vessel irradiation.

Limiting composite curves are applicable for (a) hydrostatic pressure tests and leak tests, (b) core not critical heatup/cooldown, and (c) core critical operation. The individual curves used to construct the limiting curves are described in Tables 4-2 and 4-3, for Units 1 and 2, respectively. Tables 4-2 and 4-3 show the pressure range over which each curve used to construct the composite P-T curves is limiting. The curves consist of the 10CFR50 Appendix G bolt-up limits (limits for the closure flange region that are highly stressed by the bolt preload), the non-beltline bottom head curve, the non-beltline feedwater nozzle curve, and the beltline curve. During core critical operation the entire RPV follows the saturation curve that is well to the right of the core critical curve.

4.2 NON-BELTLINE REGIONS

Non-beltline regions are defined as the vessel locations that are remote from the active fuel and where the neutron fluence is not sufficient to cause any significant shift of RT_{NDT}. Non-beltline components include most nozzles, the closure flanges, some shell plates, the top and bottom head plates and the control rod drive (CRD) penetrations.

Detailed stress analyses of the non-beltline components were performed for the BWR/6 specifically for the purpose of fracture toughness analysis. The analyses took into account all mechanical loading and anticipated thermal transients. Transients considered include 100°F/hr start-up and shutdown, SCRAM, loss of feedwater heaters or flow, loss of recirculation pump flow, and all transients involving emergency core cooling injections. Primary membrane and bending stresses and secondary membrane and bending stresses due to the most severe of these transients were used according to the ASME Code [8] to develop plots of allowable pressure (P) versus temperature relative to the reference temperature (T - RT_{NDT}). Plots were developed for the limiting BWR/4 components: the feedwater nozzle (FW) and the CRD penetration (bottom head). All other components in the non-beltline regions are categorized under one of these two components.

The P-T curves for the non-beltline region were conservatively developed for a large BWR/6 (nominal inside diameter of 251 inches). The analysis is considered appropriate for Hatch Unit 1 and Hatch Unit 2 as the plant specific geometric values are bounded by the generic analysis for a large BWR/6, as determined from Equations 4-2 and 4-3. The generic value was adapted to the conditions at Hatch Unit 1 and Hatch Unit 2 by using plant specific RT_{NDT} values for the reactor pressure vessel (RPV). The presence of nozzles and CRD penetration holes of the upper vessel and bottom head, respectively, has made the analysis different from a shell analysis such as the beltline. This was the result of the stress concentrations and higher thermal stresses for certain transient conditions experienced by the upper vessel and the bottom head.

The non-beltline curves are based on the most limiting (conservative) properties of either the upper vessel region or the bottom head. The non-beltline curves are shifted based on the most limiting initial RT_{NDT} values for the appropriate non-beltline components; the initial RT_{NDT} values were obtained from [6,7]. The individual bottom head curve is based on the non-beltline bottom head curve described in the next section. A detailed description of the construction of each non-beltline curve is included in the following sections.

4.2.1 PRESSURE TEST - NON-BELTLINE, CURVE A (USING BOTTOM HEAD)

In a BWR/6 finite element analysis, the CRD penetration region was modeled to compute the local stresses for determination of the stress intensity factor, K_I. The results of that computation were K_I = 154.3 ksi-in$^{1/2}$ for an applied pressure of 1593 psig (1563 psig preservice hydrotest pressure at the top of the vessel plus 30 psig hydrostatic pressure at the bottom of the vessel). The computed value of (T - RT_{NDT}) was 161°F; the limit for the temperature change rate is 20°F/hr.

The CRD penetration region limits were established primarily for consideration of bottom head discontinuity stresses during pressure testing.

The CRD penetration stresses were obtained from finite element analysis. These stresses, and other inputs used in the generic calculations, are shown below:

$_{pm}$ = 35.87 ksi	$_{sm}$ = 0.30 ksi	$_{ys}$ = 47.68 ksi
$_{pb}$ = -0.30 ksi	$_{sb}$ = 1.50 ksi	t = 8.0 inch

The value of M_m from Figure G-2214-1 [8] was based on a thickness of 8.0 inches; hence, $t^{1/2}$ = 2.83. The stress to yield ratio, / $_{ys}$, was calculated to be 0.78. The resulting value obtained was:

$$M_m = 2.83$$

K_{Im} is calculated from the equation in Paragraph G-2214.1 [8]:

$$K_{Im} = M_m{}^* \sigma_{pm} = 101.5 \text{ ksi-in}^{1/2}$$

K_{Ib} is calculated from the equation in Paragraph G-2214.2 [8]:

$$K_{Ib} = (2/3)\, M_m{}^* \sigma_{pb} = -0.60 \text{ ksi-in}^{1/2}$$

The total K_I is therefore:

$$K_I = 1.5 (K_{Im} + K_{Ib}) + M_m * (\sigma_{sm} + (2/3) * \sigma_{sb}) = 154.3 \text{ ksi-in}^{1/2}$$

This equation includes a safety factor of 1.5 on primary stress.

The method to solve for (T - RT_{NDT}) for a specific K_I is based on the curve in Figure G-2210-1 in ASME Appendix G [8]:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = \ln [(154.3 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 161°F$$

The generic curve was generated by scaling 154.3 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated (T - RT_{NDT}):

Pressure Test CRD Penetration K_I and (T - RT_{NDT}) as a Function Of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	T - RT_{NDT} (°F)
1563	154.3	161
1400	138.2	151
1200	118.5	138
1000	98.7	121
800	79.0	99
600	59.2	66
400	39.5	1

The highest RT_{NDT} values for the bottom head plates and welds are 10°F and 50°F, for Hatch 1 and 2, respectively [6,7]. The generic P-T curve is shifted by these values.

The P-T curve is dependent on the K_I value calculated, which is proportional to the stress and the crack depth according to the relationship:

$$K_I \quad (\quad a)^{1/2}$$
(4-1)

The stress is proportional to R/t and, for the P-T curves, crack depth, *a*, is t/4. Thus, K_I is proportional to $R/(t)^{1/2}$. The generic curve value of $R/(t)^{1/2}$, based on the generic BWR/6 bottom head dimensions, is:

Generic: $R / (t)^{1/2} = 138 / (8)^{1/2} = 49 \text{ inch}^{1/2}$ (4-2)

The Hatch Unit 1 and Hatch Unit 2 specific bottom head dimensions are R = 110 inches and t = 5.38 inches minimum, resulting in:

Hatch Unit 1 and Unit 2 specific:

$R / (t)^{1/2} = 110/ (5.38)^{1/2} = 47 \text{ inch}^{1/2}$ (4-3)

Since the generic value of $R/(t)^{1/2}$ is larger than that for Hatch Unit 1 and Hatch Unit 2, the generic P-T curve is conservative when applied to the Hatch Unit 1 and Hatch Unit 2 bottom heads.

4.2.2 CORE NOT CRITICAL HEATUP/COOLDOWN - NON-BELTLINE CURVE B (USING BOTTOM HEAD)

As discussed previously, the CRD penetration region limits were established primarily for consideration of bottom head discontinuity stresses during pressure testing. Heatup/cooldown limits were calculated by increasing the safety factor in Section 4.2.1 from 1.5 to 2.0, on the assumption that the conservative factor of 3.0 on bottom head pressure stress bounds the thermal stresses occurring during heatup/cooldown.

Subsequent analysis examined CRD penetration region limits for several emergency conditions involving severe bottom head thermal conditions. The transients with the most severe bottom head conditions were sudden start of an idle recirculation loop (cooldown) and improper start-up, or black start, from a hot standby condition with bottom head drain closed (heatup). The sudden start causes a step-change cooldown of 178°F. The improper start-up sequence involves a step-change heatup of 348°F. The result of CRD penetration region fracture toughness analysis for these conditions showed comparable P-T limits to those established assuming 3.0 times nominal pressure stress. Therefore, the CRD penetration region limits are adequate to assure structural integrity for heatup/cooldown step-changes in excess of 100°F.

The calculated value of K_I for pressure test is multiplied by a safety factor (SF) of 1.5, per ASME Appendix G [8] for comparison with K_{IR}, the material fracture toughness. A safety factor of 2.0 is used for the core not critical. Therefore, the K_I value for the core not critical condition is $(154.3 / 1.5)^* 2.0 = 205.7$ ksi-in$^{1/2}$.

Therefore, the method to solve for $(T - RT_{NDT})$ for a specific K_I is also based on the curve in Figure G-2210-1 in ASME Appendix G [8] for the core not critical:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = \ln [(205.7 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 184°F$$

The generic curve was generated by scaling 205.7 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated (T - RT_{NDT}):

Core Not Critical CRD Penetration K_I and (T - RT_{NDT}) as a Function of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	T - RT_{NDT} (°F)
1563	205.7	184
1400	184.2	175
1200	157.9	162
1000	131.6	147
800	105.3	127
600	79.0	99
400	52.6	50

The highest RT_{NDT} values for the bottom head plates and welds is 10°F and 50°F,for Hatch 1 and 2, respectively. The generic P-T curve is shifted by these values.

4.2.3 PRESSURE TEST - NON-BELTLINE CURVE A (USING FEEDWATER NOZZLE/UPPER VESSEL REGION)

CBI Nuclear (CBIN) modeled the 251-inch BWR/6 feedwater nozzles to compute local stresses for determination of the stress intensity factor, K_I. The result of that computation was K_I = 143.1 ksi-in$^{1/2}$ for an applied pressure of 1563 psig preservice hydrotest pressure. The computed value of (T - RT_{NDT}) was 154°F. The respective flaw depth and orientation used in this calculation is perpendicular to the maximum stress (hoop) at a depth of 1/4T through the corner thickness.

To evaluate the CBIN result, K_I is calculated for the upper vessel nominal stress, PR/t, according to the methods in ASME Code Appendix G (Section III or XI). The result is compared to that determined by CBIN in order to quantify the K magnification associated with the stress concentration created by the feedwater nozzles.

A calculation of K_I is shown below using the BWR/6, 251-inch dimensions:

Vessel Radius, R	126.7 inches
Vessel Thickness, t	6.5 inches
Vessel Pressure, P	1563 psig

Pressure stress: σ = PR/t = 1563 psig 126.7 inches / (6.5 inches) = 30,466 psi

The factor F (a/r_n) from Figure A5-1 of WRC-175 [5] is 1.6 where :

a =	lesser of 1/4 t_n or 1/4 t_v	
t_n =	thickness of nozzle	= 7.13 inches
t_v =	thickness of vessel	= 6.5 inches
r_n =	apparent radius of nozzle	= r_i + 0.29 r_c
r_i =	actual inner radius of nozzle	= 6 inches
r_c =	nozzle radius (nozzle corner radius)	= 4.0 inches

Thus, a/r_n = 1.63 / 6.94 = 0.23 and the ratio of K_I around the feedwater nozzle to the membrane stress · ($a)^{1/2}$ at places with no geometric discontinuity is 1.6.

Including the safety factor of 1.3, the stress intensity factor, K_I, is $1.3*\sigma*(\pi a)^{1/2}*F(a/r_n)$:

$$\text{Nominal } K_I = 1.3 \cdot 30.466 \cdot (\pi \cdot 1.63)^{1/2} \cdot 1.6 = 143 \text{ ksi-in}^{1/2}$$

The method to solve for $(T - RT_{NDT})$ for a specific K_I is based on the curve in Figure G-2210-1 in ASME Appendix G [8]:

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 1n [(143 - 26.78) / 1.223] / 0.0145 - 160$$
$$(T - RT_{NDT}) = 154°F$$

The generic pressure test P-T curve was generated by scaling 143 ksi-in$^{1/2}$ by the nominal pressures and calculating the associated $(T - RT_{NDT})$:

Pressure Test Feedwater Nozzle K_I and $(T - RT_{NDT})$ as a Function of Pressure

Nominal Pressure (psig)	K_I (ksi-in$^{1/2}$)	$(T - RT_{NDT})$ (°F)
1563	143	154
1400	128	145
1200	110	131
1000	92	114
800	73	91
600	55	56
400	37	-16

The P-T curve is dependent on the K_I value calculated, which is proportional to the stress and the crack depth according to the relationship:

$$K_I \propto \sigma (\pi a)^{1/2}$$

The stress is proportional to R/t and, for the P-T curves, crack depth, *a*, is t/4. Thus, K_I is proportional to $R/(t)^{1/2}$.

The generic curve value of $R/(t)^{1/2}$, based on the BWR/6, 251-inch feedwater nozzle dimensions is:

Generic: $R/(t)^{1/2} = 126.7 / (6.5)^{1/2} = 49.7 \text{ inch}^{1/2}$

where t is the nominal vessel thickness. The Hatch Unit 1 and Hatch Unit 2 specific vessel shell dimensions applicable to the feedwater nozzle location are R = 110 inches and t = 5.38 inches nominal.

Hatch Unit 1 and Unit 2 specific: $R/(t)^{1/2} = 110 / (5.38)^{1/2} = 47.4 \text{ inch}^{1/2}$

Since the generic value of $R/(t)^{1/2}$ is greater than that for Hatch Unit 1 and Hatch Unit 2, the generic P-T curve is conservative when applied to the Hatch Unit 1 and Hatch Unit 2 feedwater nozzles.

As discussed below, the highest RT_{NDT} values for the nozzle materials are 40°F and 26°F, for Hatch 1 and 2, respectively. The generic pressure test P-T curve is applied to the Hatch Unit 1 and Hatch Unit 2 feedwater nozzle curves by shifting the P vs. (T - RT_{NDT}) values above to reflect the RT_{NDT} values of 40°F and 26°F.

4.2.4 CORE NOT CRITICAL HEATUP/COOLDOWN - NON-BELTLINE CURVE B (USING FEEDWATER NOZZLE/UPPER VESSEL REGION)

The feedwater nozzle was selected to represent non-beltline components for fracture toughness analyses because the stress conditions are the most severe experienced in the vessel. In addition to the more severe pressure and piping load stresses resulting from the nozzle discontinuity, the feedwater nozzle region experiences relatively cold feedwater flow in hotter vessel coolant.

Stresses are taken from finite element analysis done specifically for fracture toughness analysis purposes. Analyses were performed for all feedwater nozzle transients that involve rapid temperature changes. The most severe of these was normal operation with cold 40°F feedwater injection, which is equivalent to hot standby.

The non-beltline curves based on feedwater nozzle limits were calculated according to the methods for nozzles in Appendix 5 of the Welding Research Council (WRC) Bulletin 175 [5].

The stress intensity factor for a nozzle flaw under primary stress conditions (K_{IP}) is given in WRC Bulletin 175 Appendix 5 [5] by the expression for a flaw at a hole in a flat plate:

$$K_{IP} = SF \cdot \left(\quad a \right)^{1/2} \cdot F(a/r_n) \qquad (4\text{-}4)$$

where SF is the safety factor applied per WRC Bulletin 175 [5] recommended ranges, and $F(a/r_n)$ is the shape correction factor.

Finite element analysis of a nozzle corner flaw was performed to determine appropriate values of $F(a/r_n)$ for Equation 4-4. These values are shown in Figure A5-1 of WRC Bulletin 175 [5].

The stresses used in Equation 4-4 were taken from BWR/6 design stress reports for the feedwater nozzle. The stresses considered are primary membrane, $_{pm}$, and primary bending, $_{pb}$. Secondary membrane, $_{sm}$, and secondary bending, $_{sb}$, stresses are included in the total K_I by using ASME Appendix G [8] methods for secondary portion, K_{Is}:

$$K_{Is} = M_m (\; _{sm} + (2/3) \cdot \quad _{sb})$$
(4-5)

In the case where the total stress exceeded yield stress, a plasticity correction factor was applied based on the recommendations of WRC Bulletin 175 Section 5.C.3 [5]. However, the correction was not applied to primary membrane stresses because stresses that are based on equilibrium considerations (i.e., primary membrane) are not displacement controlled and are not reduced or changed by deformation of the component. K_{IP} and K_{Is} are added to obtain the total value of stress intensity factor, K_I. A safety factor of 1.6 is applied to primary stresses for core not critical heatup/cooldown conditions.

Once K_I was calculated, the following relationship was used to determine (T - RT_{NDT}). The highest RT_{NDT} for the appropriate non-beltline components was then used to establish the P-T curves.

$$(T - RT_{NDT}) = \ln [(K_I - 26.78) / 1.223] / 0.0145 - 160 \qquad (4\text{-}6)$$

Example: Core Not Critical Heatup/Cooldown Calculation for Feedwater Nozzle/Upper Vessel Region

The non-beltline core not critical heatup/cooldown curve was based on the feedwater nozzle generic analysis, where feedwater injection of 40°F into the vessel while at operating conditions (551.4°F and 1050 psig) was the limiting normal or upset condition from a brittle fracture perspective. The feedwater nozzle corner stresses were obtained from finite element analysis. These stresses, and other inputs used in the generic calculations, are shown below:

$_{pm}$ = 20.49 ksi	$_{sm}$ = 16.19 ksi	$_{ys}$ = 45.0 ksi	t = 7.5 inch
$_{pb}$ = 0.22 ksi	$_{sb}$ = 19.04 ksi	*a* = 1.88 inch	r_n = 6.94 inch

In this case the total stress, 55.94 ksi, exceeds the yield stress, $_{ys}$, so the correction factor, R, is calculated to consider the nonlinear effects in the plastic region according to the following equation based on the assumptions and recommendation of WRC Bulletin 175 [5]. (The value of specified yield stress is for the material at the temperature under consideration. For conservatism, the temperature assumed for the crack root is the inside surface temperature.)

$$R = [\ _{ys} -\ _{pm} + ((\ _{total} -\ _{ys}) / 30)] / (\ _{total} -\ _{pm}) \quad (4\text{-}7)$$

For the stresses given, the ratio, R = 0.70. Therefore, all the stresses are adjusted by the factor 0.70, except for $_{pm}$. The resulting stresses are:

$$_{pm} = 20.49 \text{ ksi} \qquad _{sm} = 11.33 \text{ ksi}$$
$$_{pb} = 0.15 \text{ ksi} \qquad _{sb} = 13.33 \text{ ksi}$$

The value of M_m from Figure G-2214-1 [8] was based on a thickness of 7.5 inches; hence, $t^{1/2} = 2.74$. The stress to yield ratio, $/\ _{ys}$, was conservatively assumed to be 1.0. The resulting value obtained was: $M_m = 2.84$.

The value $F(a/r_n)$, taken from Figure A5-1 of WRC Bulletin 175 [5] for an a/r_n of 0.27, is 1.5; however, 1.6 is used to be conservative.

$$F(a / r_n) = 1.6$$

K_{IP} is calculated from Equation 4-4:

$$K_{IP} = 1.6 \cdot (20.49 + 0.15) \cdot (\ \cdot 1.88)^{1/2} \cdot 1.6$$
$$K_{IP} = 128.4 \text{ ksi-in}^{1/2}$$

K_{Is} is calculated from Equation 4-5:

$$K_{Is} = 2.84 \cdot (11.33 + 2/3 \cdot 13.33)$$
$$K_{Is} = 57.4 \text{ ksi-in}^{1/2}$$

The total K_I is, therefore, 186 ksi-in$^{1/2}$.

The total K_I is substituted into Equation 4-6 to solve for $(T - RT_{NDT})$:

$(T - RT_{NDT}) = \ln [(186 - 26.78) / 1.223] / 0.0145 - 160$

$(T - RT_{NDT}) = 176°F$

The generic curve was generated by scaling the stresses used to determine the K_I; this scaling was performed after the adjustment to stresses above yield. The primary stresses were scaled by the nominal pressures, while the secondary stresses were scaled by the temperature difference of the 40°F water injected into the hot reactor vessel nozzle. In the base case that yielded a K_I value of 186 ksi-in$^{1/2}$, the pressure is 1050 psig and the hot reactor vessel temperature is 551.4°F. Since the reactor vessel temperature follows the saturation temperature curve, the secondary stresses are scaled by $(T_{saturation} - 40) / (551.4 - 40)$. From K_I the associated $(T - RT_{NDT})$ can be calculated:

Core Not Critical Feedwater Nozzle K_I and $(T - RT_{NDT})$ as a Function of Pressure

Nominal Pressure (psig)	Saturation Temp. (°F)	K_I (ksi-in$^{1/2}$)	$(T - RT_{NDT})$ (°F)
1563	604	226	191
1400	588	213	187
1200	557	198	181
1050	551	186	176
1000	546	182	174
800	520	166	167
600	489	146	156
400	448	115	135

The highest non-beltline RT_{NDT} values for the feedwater region components are 40°F and 26°F (steam outlet nozzle) for Hatch Unit 1 and Hatch Unit 2, respectively [6,7]. The generic curve is applied to the Hatch Unit 1 and Hatch Unit 2 upper vessels by shifting the P vs. $(T - RT_{NDT})$ values above to reflect the RT_{NDT} values of 40°F and 26°F.

4.3 CORE BELTLINE REGION

The pressure-temperature (P-T) operating limits for the beltline region are determined according to the ASME Code. As the beltline fluence increases with the increase in operating life, the P-T curves shift to a higher temperature.

The stress intensity factors (K_I), calculated for the beltline region according to ASME Code Appendix G procedures [8], were based on a combination of pressure and thermal stresses for a 1/4T flaw in a flat plate. The pressure stresses were calculated using thin-walled cylinder equations. Thermal stresses were calculated assuming the through-wall temperature distribution of a flat plate; values were calculated for 100°F/hr thermal gradient. The shift value of the most limiting ART material was used to adjust the RT_{NDT} values for the P-T limits.

4.3.1 BELTLINE REGION - PRESSURE TEST

The methods of ASME Code Section XI, Appendix G [8] are used to calculate the pressure test beltline limits. The vessel shell, with an inside radius (R) to minimum thickness (t_{min}) ratio of 15, is treated as a thin-walled cylinder. The maximum stress is the hoop stress, given as:

$$_{m} = PR / t_{min} \qquad (4\text{-}8)$$

The stress intensity factor, K_{Im}, is calculated using Figure G-2214-1 of the ASME Code Section XI, Appendix G [8], accounting for the proper ratio of stress to yield strength. Figure G-2214-1 was taken from Welding Research Council (WRC) Bulletin 175 [5], based on a 1/4T radial flaw with a six-to-one aspect ratio (length of 1.5T). The flaw is oriented normal to the maximum stress direction, in this case a vertically oriented flaw. This orientation is used even in the case where the circumferential weld is the limiting beltline material.

The calculated value of K_{Im} for pressure test is multiplied by a safety factor (SF) of 1.5, per ASME Appendix G [8] for comparison with K_{IR}, the material fracture toughness. A safety factor of 2.0 is used for the core not critical and core critical conditions.

The relationship between K_{IR} and temperature relative to reference temperature ($T - RT_{NDT}$) is shown in Figure G-2210-1 of ASME Section XI Appendix G [8], represented by the relationship:

$$K_{Im} \cdot SF = K_{IR} = 1.223 \exp[0.0145 (T - RT_{NDT} + 160)] + 26.78 \qquad (4\text{-}9)$$

This relationship is derived in the Welding Research Council (WRC) Bulletin 175 [5] as the lower bound of all dynamic fracture toughness and crack arrest toughness data. This relationship provides values of pressure versus temperature (from K_{IR} and ($T - RT_{NDT}$), respectively).

GE's current practice for the pressure test curve is to add a stress intensity factor, K_{It}, for a heatup/cooldown rate of 20°F/hr to provide operating flexibility. For the core not critical and core critical condition curves, a stress intensity factor is added for a heatup/cooldown rate of 100°F/hr. The K_{It} calculation for a heatup/cooldown rate of 100°F/hr is described in Sections 4.3.3 and 4.3.4.

4.3.2 CALCULATIONS FOR THE BELTLINE REGION - PRESSURE TEST

This sample calculation is for a pressure test pressure of 1105 psig at 54 EFPY for Hatch Unit 1. The following inputs were used in the beltline limit calculation:

Adjusted RT_{NDT} = Initial RT_{NDT} + Shift	A = -20 + 187.2 = 167.2 °F (Based on ART values in Section 3)
Vessel Height	H = 825 inches
Bottom of Active Fuel Height	B = 208.5 inches
Vessel Radius (to inside of clad)	R = 110 inches
Minimum Vessel Thickness (without clad)	t = 5.38 inches
Limiting Beltline Material Yield Strength	$_y$ = 64.4 ksi

Pressure is calculated to include hydrostatic pressure for a full vessel:

$$P = 1105 \text{ psi} + (H - B)\ 0.0361 \text{ psi/inch} = P \text{ psig} \qquad (4\text{-}10)$$

$$= 1105 + (825 - 208.5)\ 0.0361 = 1127 \text{ psig}$$

Pressure stress:

$$= PR/t \qquad (4\text{-}11)$$
$$= 1.127 \cdot 110 / 5.38 = 23.0 \text{ ksi}$$

The factor M_m (= 2.23) depends on (/ $_y$ = 23.0 / 64.4) and $t^{1/2}$ and is determined from Figure G-2214-1 of the ASME Code Appendix G [8], where t is the minimum vessel thickness without cladding. The stress intensity factor for the pressure stress is $K_{Im} = M_m \cdot$ The stress intensity factor for the thermal stress, K_{It}, is calculated as described in Section 4.3.4 except that the value of "G" is 20°F/hr instead of 100°F/hr.

Equation 4-9 can be rearranged, and 1.5 K_{Im} substituted for K_{IR}, to solve for (T - RT_{NDT}). Using ASME Section XI Appendix G, Fig. G-2210-1 [8], K_{Im}= 51.3, and K_{It}= 1.73 for a 20°F/hr heatup/cooldown rate with a vessel thickness, t, that includes cladding:

$$\begin{aligned}(T - RT_{NDT}) &= \ln[(1.5 \cdot K_{Im} + K_{It} - 26.78) / 1.223] / 0.0145 - 160 \qquad (4\text{-}12)\\ &= \ln[(1.5 \cdot 51.3 + 1.73 - 26.78) / 1.223] / 0.0145 - 160\\ &= 98.5°F\end{aligned}$$

T can be calculated by adding the adjusted RT_{NDT}:

$$T = 98.5 + 167 = 265.5°F \qquad \text{for } P = 1105 \text{ psig}$$

4.3.3 BELTLINE REGION - CORE NOT CRITICAL HEATUP/COOLDOWN

The beltline curves for core not critical heatup/cooldown conditions are influenced by pressure stresses and thermal stresses, according to the relationship in ASME Section XI Appendix G [8]:

$$K_{IR} = 2.0 \cdot K_{Im} + K_{It} \qquad (4\text{-}13)$$

where K_{Im} is primary membrane K due to pressure and K_{It} is radial thermal gradient K due to heatup/cooldown.

The pressure stress intensity factor K_{Im} is calculated by the method described above, the only difference being the larger safety factor applied. The thermal gradient stress intensity factor calculation is described below.

The thermal stresses in the vessel wall are caused by a radial thermal gradient that is created by changes in the adjacent reactor coolant temperature in heatup or cooldown conditions. The stress intensity factor is computed by multiplying the coefficient M_t from Figure G-2214-2 of ASME Appendix G [8] by the through-wall temperature gradient T_w, given that the temperature gradient has a through-wall shape similar to that shown in Figure G-2214-3 of ASME Appendix G [8]. The relationship used to compute the through-wall T_w is based on one-dimensional heat conduction through an insulated flat plate:

$$^2T(x,t) / \quad x^2 = 1 / \quad (\quad (x,t) / \quad t)$$

(4-14)

where T(x,t) is temperature of the plate at depth x and time t, and is the thermal diffusivity.

The maximum stress will occur when the radial thermal gradient reaches a quasi-steady state distribution, so that $T(x,t) / \quad t = dT(t) / dt = G$, where G is the heatup/cooldown rate, normally 100°F/hr. The differential equation is integrated over x for the following boundary conditions:

1. Vessel inside surface ($x = 0$) temperature is the same as coolant temperature, T_0.
2. Vessel outside surface ($x = C$) is perfectly insulated; the thermal gradient $dT/dx = 0$.

The integrated solution results in the following relationship for wall temperature:

$$T = Gx^2 / 2 \ - GCx / \ + T_0 \qquad (4\text{-}15)$$

This equation is normalized to plot $(T - T_0) / \ T_w$ versus x / C.

The resulting through-wall gradient compares very closely with Figure G-2214-3 of ASME Appendix G [8]. Therefore, T_w calculated from Equation 4-14 is used with the appropriate M_t of Figure G-2214-2 of ASME Appendix G [8] to compute K_{It} for heatup and cooldown.

The M_t relationships were derived in the Welding Research Council (WRC) Bulletin 175 [5] for infinitely long cracks of 1/4T and 1/8T. For the flat plate geometry and radial thermal gradient, orientation of the crack is not important.

4.3.4 CALCULATIONS FOR THE BELTLINE REGION CORE NOT CRITICAL HEATUP/COOLDOWN

This sample calculation is for a pressure of 1105 psi for 54 EFPY.

The core not critical heatup/cooldown curve at 1105 psig uses the same K_{Im} as the pressure test curve, but with a safety factor of 2.0 instead of 1.5. The increased safety factor is used because the heatup/cooldown cycle represents an operational rather than test condition that necessitates a higher safety factor. In addition, there is a K_{It} term for the thermal stress. The additional inputs used to calculate K_{It} are:

Heatup/cooldown rate, normally 100°F/hr, G = 100 °F/hr

Minimum vessel thickness, including clad thickness, C = 0.47 ft (5.69 inches)

Thermal diffusivity at 550°F (most conservative value), = 0.354 ft ^{2}/ hr [9]

Equation 4-15 can be solved for the through-wall temperature (x = C), resulting in the absolute value of T for heatup or cooldown of:

$$T = GC^2/2 \qquad (4\text{-}16)$$

$$= 100\,(0.47)^2 / (2 \bullet 0.354) = 31.2°F$$

The analyzed case for thermal stress is a 1/4T flaw depth with wall thickness of C. The corresponding value of M_t (=0.2775) can be found from ASME Appendix G, Figure G-2214-2 [8]. Thus the thermal stress intensity factor, $K_{It} = M_t \cdot T = 8.66$, can be calculated.

The pressure and thermal stress terms are substituted into Equation 4-9 to solve for (T - RT_{NDT}):

$$(T - RT_{NDT}) = \ln[((2 \cdot K_{Im} + K_{It}) - 26.78) / 1.223] / 0.0145 - 160 \quad (4\text{-}17)$$

$$= \ln[(2 \cdot 51.3 + 8.66 - 26.78) / 1.223] / 0.0145 - 160$$

$$= 132\ °F$$

T can be calculated by adding the adjusted RT_{NDT}:

$$T = 132 + 167 = 299\ °F \quad \text{for } P = 1105 \text{ psig}$$

4.4 CLOSURE FLANGE REGION

10CFR50 Appendix G [1] sets several minimum requirements for pressure and temperature in addition to those outlined in the ASME Code, based on the closure flange region RT_{NDT}. In some cases, the results of analysis for other regions exceed these requirements and closure flange limits do not affect the shape of the P-T curves. However, some closure flange requirements do impact the curves, as is true with Hatch Unit 1 and Hatch Unit 2 at low pressures.

The original ASME Code requirement for bolt-up was at qualification temperature (T_{30L}) plus 60°F. The Code used for the currently licensed P-T curves is the 1989 ASME Code, no addenda. The ASME Code requirements state in Paragraph G-2222(c) that, for application of full bolt preload and reactor pressure up to 20% of hydrostatic test pressure, the RPV metal temperature must be at RT_{NDT} or greater. The approach used for Hatch Unit 1 and Hatch Unit 2 for the bolt-up temperature was based on a more conservative value of (RT_{NDT} + 60), or the LST of the bolting materials, whichever is greater. The 60°F adder is included by GE for two reasons: 1) the pre-1971 requirements of the ASME Code Section III, Subsection NA, Appendix G included the 60°F adder, and 2) inclusion of the additional 60°F requirement above the RT_{NDT} provides the additional assurance that a flaw size between 0.1 and 0.24 inches is acceptable. The limiting initial RT_{NDT} values for the closure flange region were 16°F for Unit 1 and 30°F for Unit 2 due to the flange, upper vessel and top head plate materials, and the LST of the closure studs was 70°F for both units, so the bolt-up temperature values used were 76°F (Unit 1) and 90°F (Unit 2). This conservatism is appropriate because bolt-up is one of the more limiting operating conditions (high stress and low temperature) for brittle fracture.

10CFR50 Appendix G, paragraph IV.A.2 [1] including Table 1, sets minimum temperature requirements for pressure above 20% hydrotest pressure based on the RT_{NDT} of the closure region. Curve A temperature must be no less than (RT_{NDT} + 90°F) and Curve B temperature no less than (RT_{NDT} + 120°F).

For pressures below 20% of preservice hydrostatic test pressure (312 psig) and with full bolt preload, the closure flange region metal temperature is required to be at RT_{NDT} or greater as described above. At low pressure, the ASME Code [8] allows the beltline and bottom head regions to experience even lower metal temperatures than the flange region RT_{NDT}. However, temperatures should not be permitted to be lower than 68°F for the reason discussed below.

The shutdown margin, provided in the Hatch Unit 1 and Hatch Unit 2 Technical Specification, is calculated for a water temperature of 68°F. Shutdown margin is the quantity of reactivity needed for a reactor core to reach criticality with the strongest-worth control rod fully withdrawn and all other control rods fully inserted. Although it may be possible to safely allow the water temperature to fall below this 68°F limit, further extensive calculations would be required to justify a lower temperature. The 76°F (Unit 1) and 90°F (Unit 2) limits apply when the head is on and tensioned and the 68°F limit when the head is off, while fuel is in the vessel. When the head is not tensioned and fuel is not in the vessel, the requirements of 10CFR50 Appendix G [1] do not apply, and there are no limits on the vessel temperatures.

4.5 CORE CRITICAL OPERATION REQUIREMENTS OF 10CFR50, APPENDIX G

Curve C, the core critical operation curve, is generated from the requirements of 10CFR50 Appendix G [1, Table 1]. Table 1 of [1] requires that core critical P-T limits be 40°F above any Curve A or B limits when pressure exceeds 20% of the pre-service system hydrotest pressure. Curve B is more limiting than Curve A, so limiting Curve C values are at least Curve B plus 40°F for pressures above 312 psig.

Table 1 of 10CFR50 Appendix G [1] indicates that for a BWR with water level within normal range for power operation, the allowed temperature for initial criticality at the closure flange region is (RT_{NDT} + 60°F) at pressures below

312 psig. This requirement makes the minimum criticality temperatures 76°F (Unit 1) and 90°F (Unit 2), based on RT_{NDT} values of 16°F and 30°F for Unit 1 and 2, respectively. In addition, above 312 psig the Curve C temperature must be at least the greater of RT_{NDT} of the closure region + 160°F or the temperature required for the hydrostatic pressure test (Curve A at 1105 psig). Therefore, this requirement causes a temperature shift in Curve C at 312 psig.

Table 4-1: Summary of the 10CFR50 Appendix G Requirements

Operating Condition and Pressure	Minimum Temperature Requirement
I. Hydrostatic Pressure Test & Leak Test (Core is Not Critical) - Curve A	
1. At ≤ 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 60°F*
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 90°F
II. Normal operation (heatup and cooldown), including anticipated operational occurrences	
a. Core not critical - Curve B	
1. At ≤ 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 60°F*
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits or of highest closure flange region initial RT_{NDT} + 120°F
b. Core critical - Curve C	
1. At ≤ 20% of preservice hydrotest pressure, with the water level within the normal range for power operation	Larger of ASME Limits + 40°F or of a.1
2. At > 20% of preservice hydrotest pressure	Larger of ASME Limits + 40°F or of a.2 + 40°F or the minimum permissible temperature for the inservice system hydrostatic pressure test

*60°F adder is included by GE as an additional conservatism as discussed in Section 4.4

Table 4-2: Composite and Individual Curves Used To Construct Composite P-T Curves at 54 EFPY (Unit 1)

Curve	Curve Description	Curve Limiting Over Pressure Range, (Psig)
Curve A	10CFR50 Bolt-up Limits	0 - 410
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	none
	Beltline Limits	410 - 1400
Curve B	10CFR50 Bolt-up Limits	0 - 50
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	50-290
	Beltline Limits	290- 1400
Curve C	10CFR50 Bolt-up Limits	0 - 20
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	20-290
	Beltline Limits	290 - 1400

Note: The core critical operation curve is identical to the core not critical heatup/cooldown curve but shifted by 40°F, as required in 10CFR50, Appendix G [1]. Hence the methods used for determining the core not critical heatup/cooldown curves apply to the core critical curves, as well.

Table 4-3: Composite and Individual Curves Used To Construct Composite P-T Curves at 54 EFPY (Unit 2)

Curve	Curve Description	Curve Limiting Over Pressure Range, (Psig)
Curve A	10CFR50 Bolt-up Limits	0 - 610
	Bottom Head Limits (CRD Nozzle)	610-1400
	FW Nozzle Limits	none
	Beltline Limits	none
Curve B	10CFR50 Bolt-up Limits	0 - 90
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	90-960
	Beltline Limits	960-1400
Curve C	10CFR50 Bolt-up Limits	0 - 30
	Bottom Head Limits (CRD Nozzle)	none
	FW Nozzle Limits	30-960
	Beltline Limits	960 - 1400

Note: The core critical operation curve is identical to the core not critical heatup/cooldown curve but shifted by 40°F, as required in 10CFR50, Appendix G [1]. Hence the methods used for determining the core not critical heatup/cooldown curves apply to the core critical curves, as well.

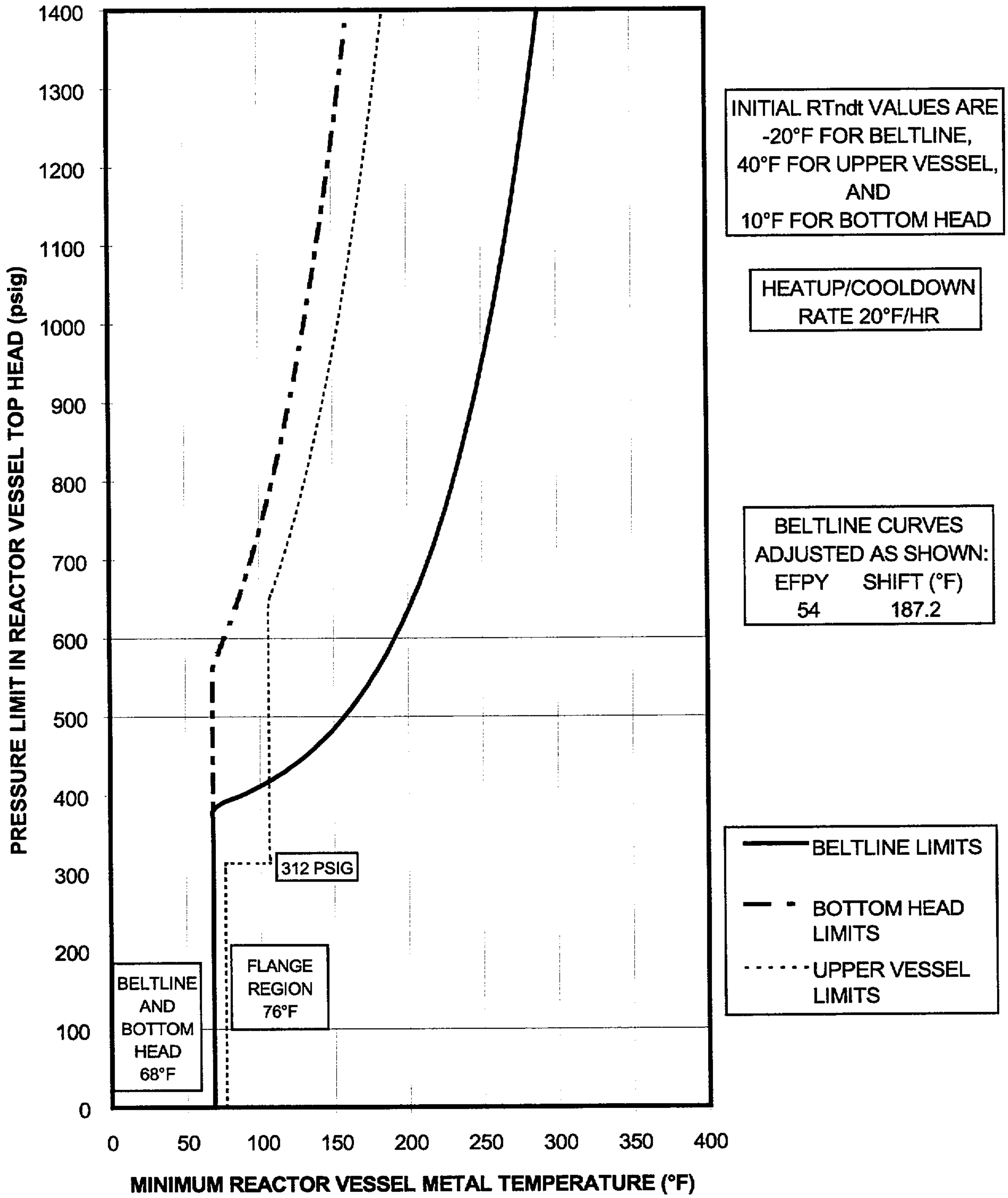


Figure 4-1: Pressure Test Curve (Curve A) [Unit 1]

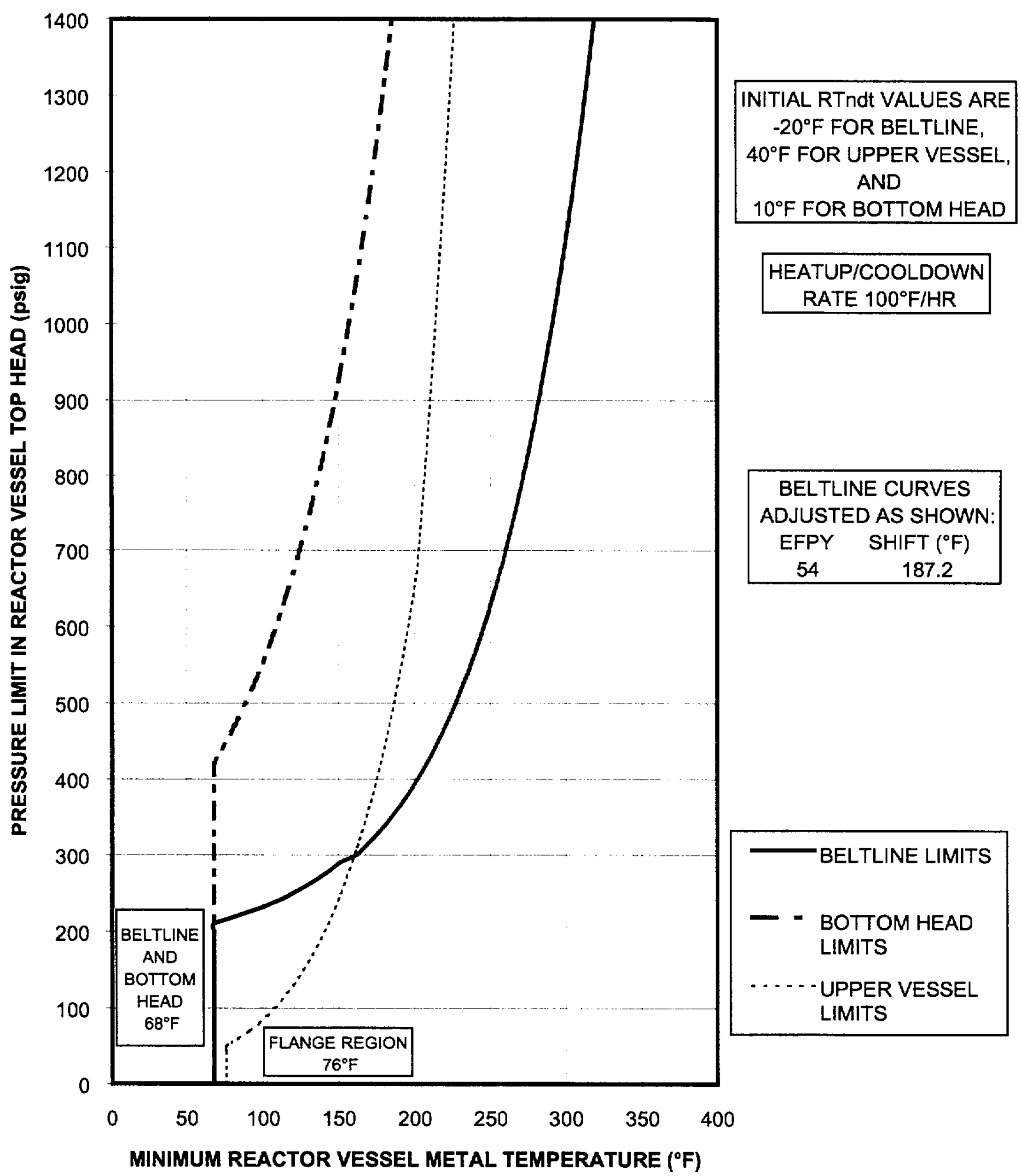


Figure 4-2: Non-Nuclear Heatup/Cooldown (Curve B) [Unit 1]

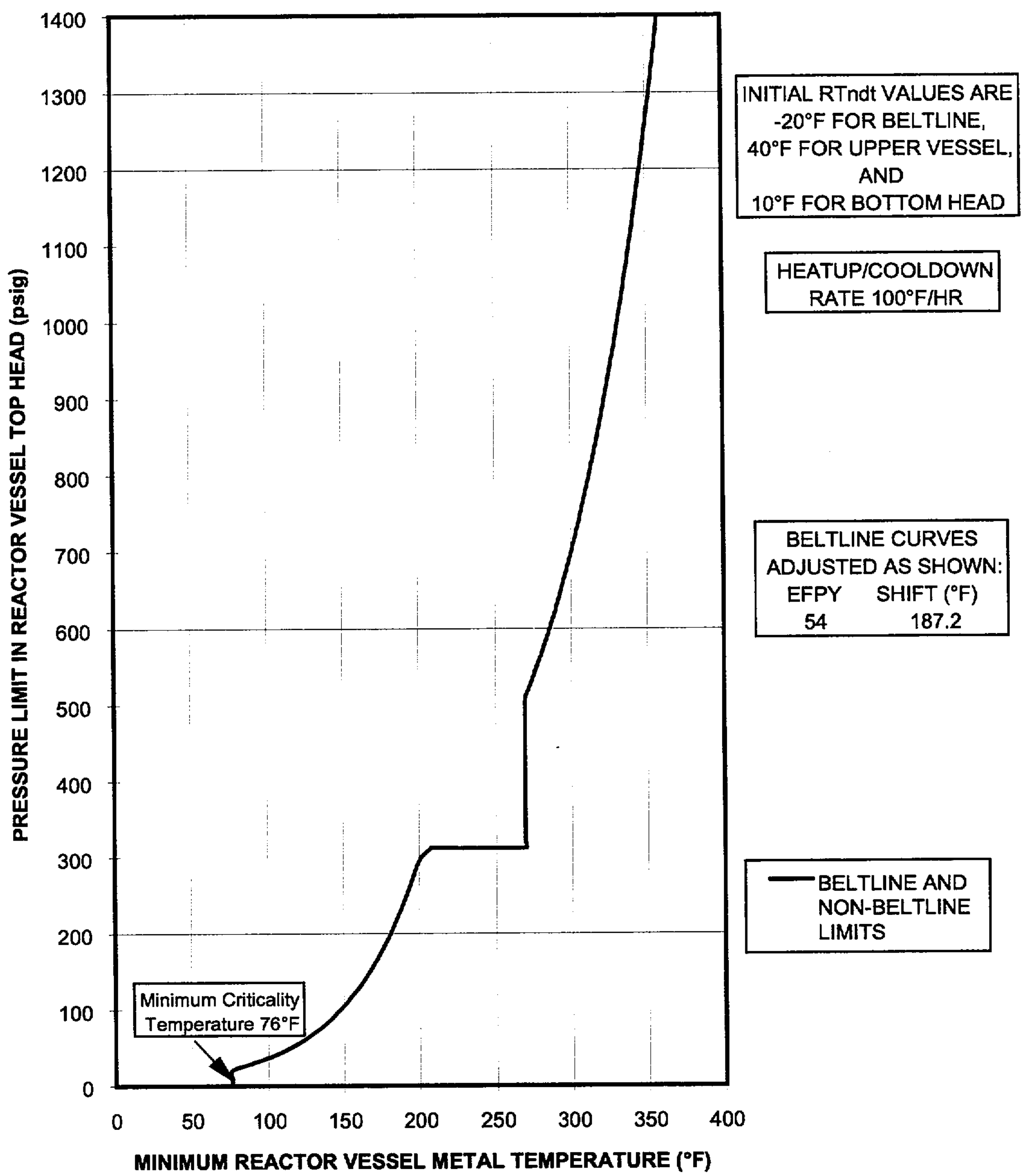


Figure 4-3: Core Critical Curve (Curve C) [Unit 1]

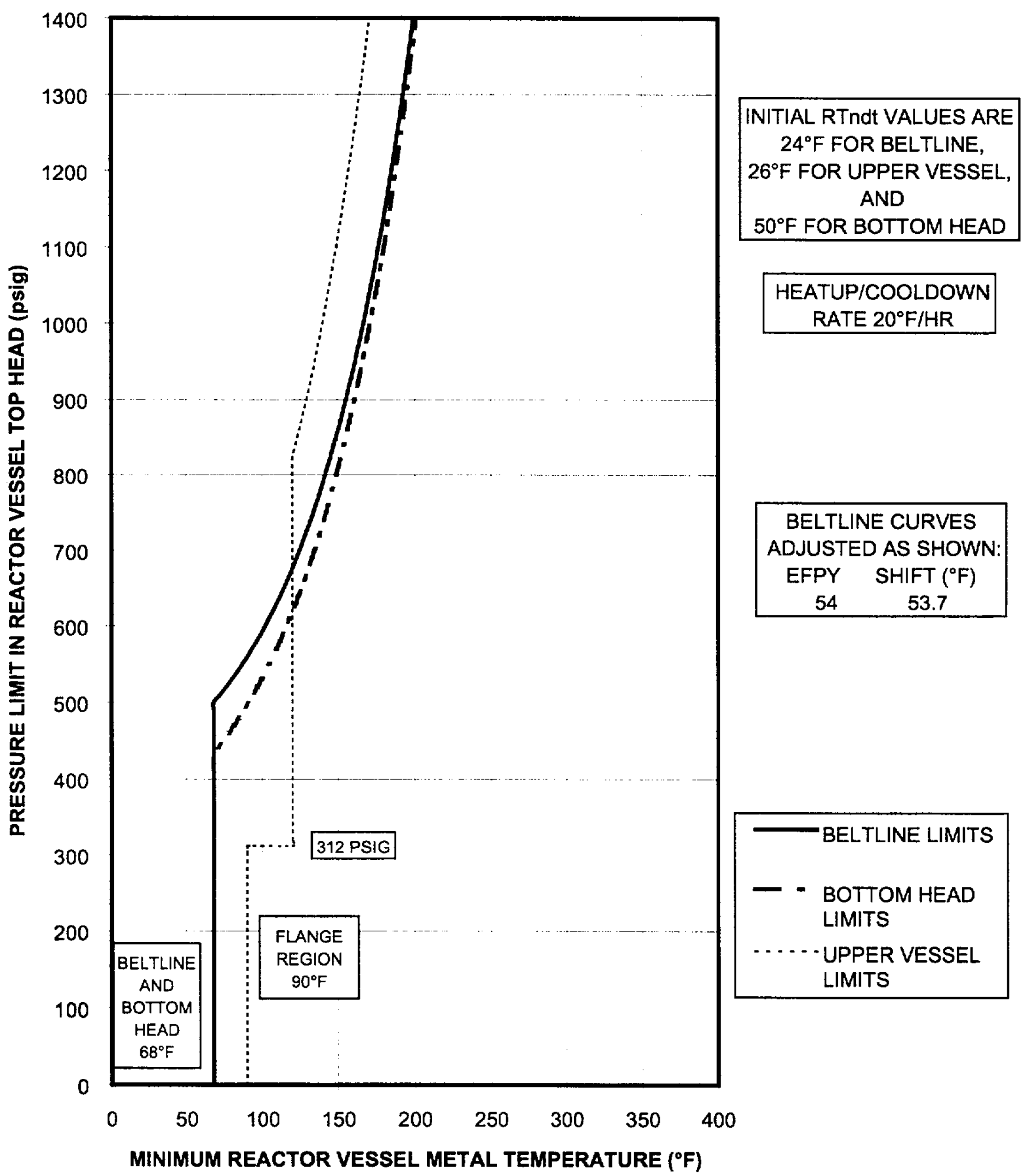


Figure 4-4: Pressure Test Curve (Curve A) [Unit 2]

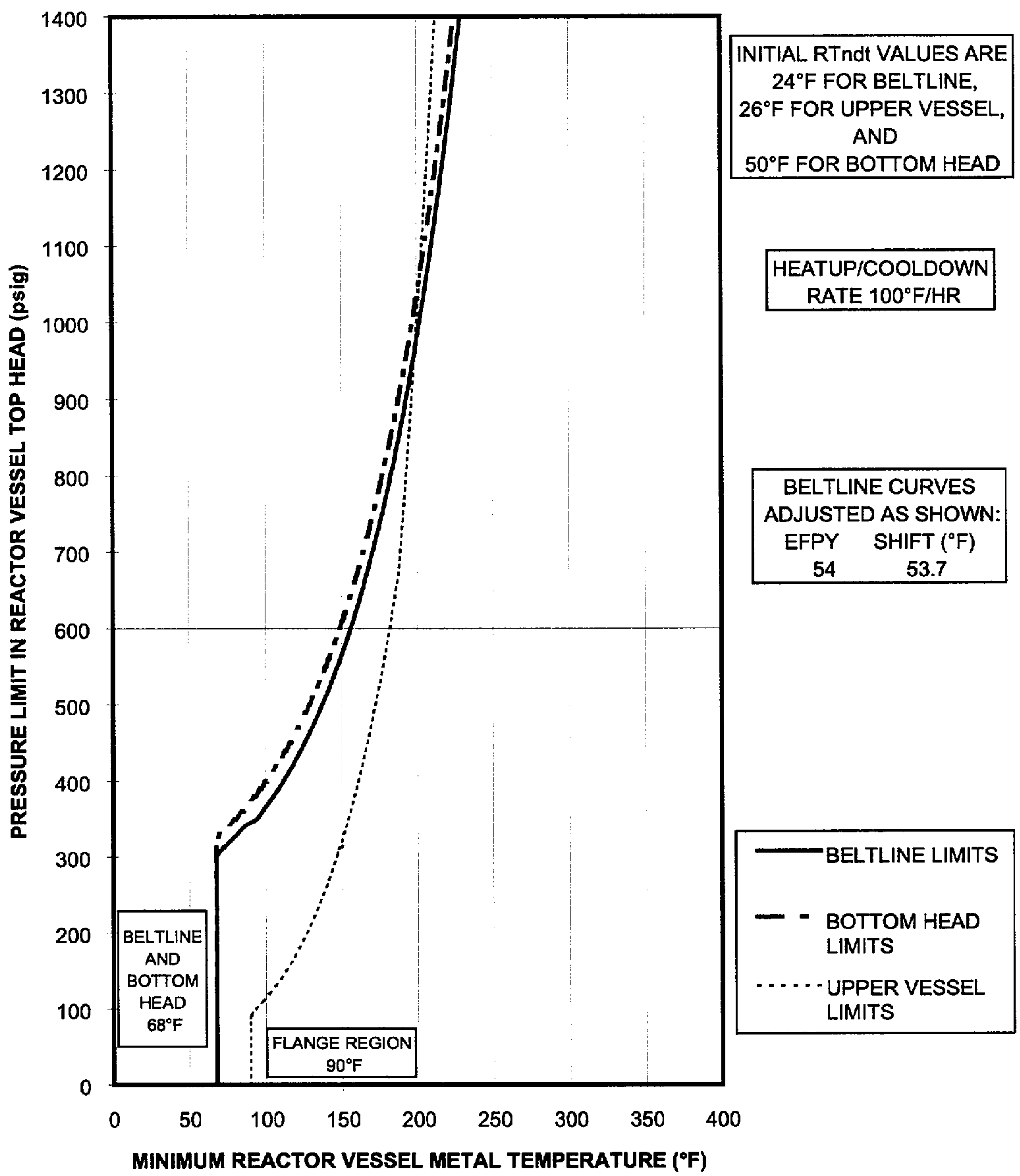


Figure 4-5: Non-Nuclear Heatup/Cooldown (Curve B) [Unit 2]

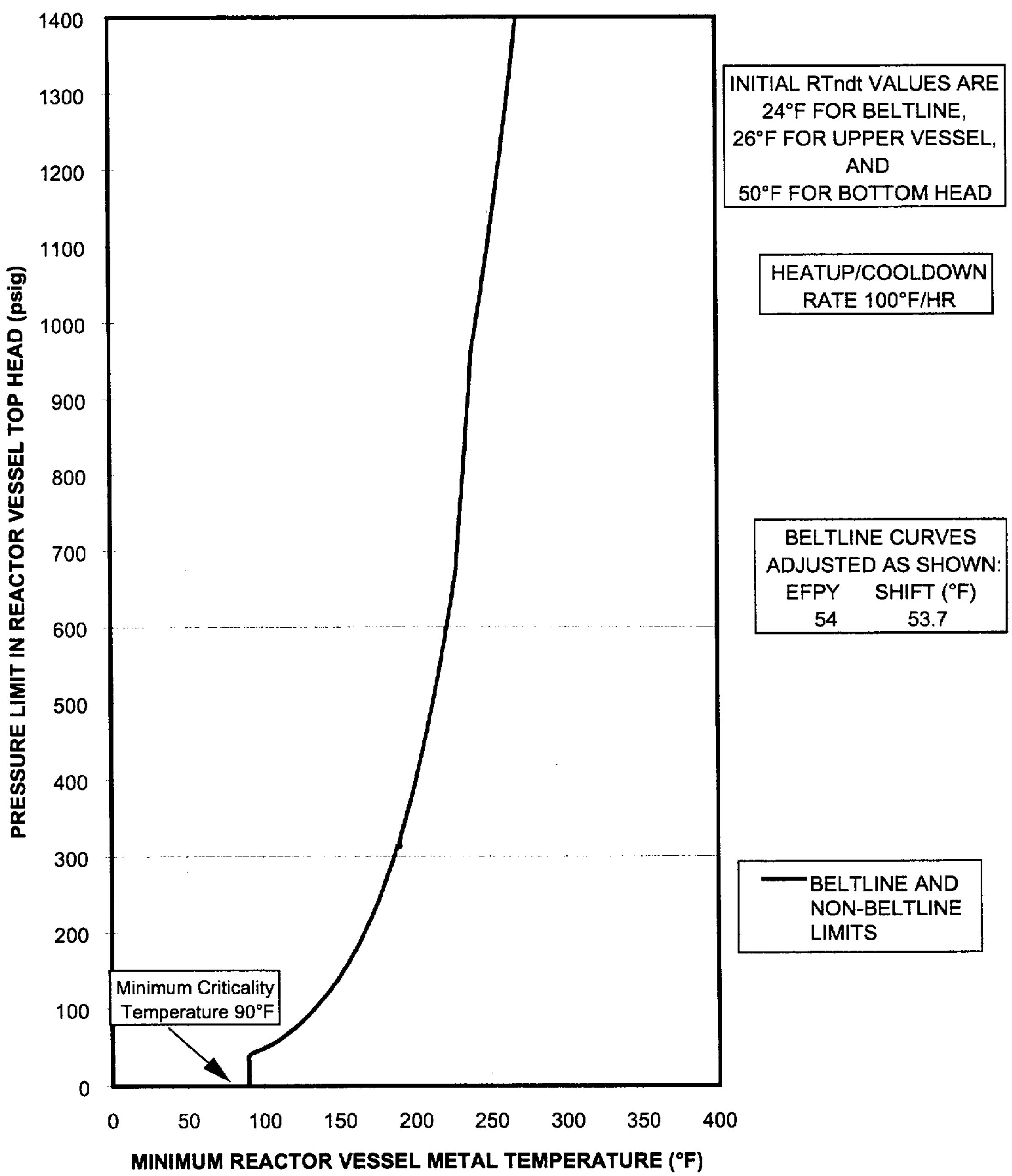


Figure 4-6: Core Critical Curve (Curve C) [Unit 2]

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	82.2	145.2	185.2
230	68.0	68.0	76.0	68.0	97.4	147.4	187.4
240	68.0	68.0	76.0	68.0	109.8	149.4	189.4

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
250	68.0	68.0	76.0	68.0	120.3	151.4	191.4
260	68.0	68.0	76.0	68.0	129.4	153.3	193.3
270	68.0	68.0	76.0	68.0	137.5	155.1	195.1
280	68.0	68.0	76.0	68.0	144.7	157.0	197.0
290	68.0	68.0	76.0	68.0	151.2	158.7	198.7
300	68.0	68.0	76.0	68.0	161.5	160.3	201.5
310	68.0	68.0	76.0	68.0	166.8	162.0	206.8
312.5	68.0	68.0	76.0	68.0	168.1	162.3	208.1
312.5	68.0	68.0	106.0	68.0	168.1	162.3	269.2
320	68.0	68.0	106.0	68.0	171.7	163.5	269.2
330	68.0	68.0	106.0	68.0	176.3	165.1	269.2
340	68.0	68.0	106.0	68.0	180.6	166.6	269.2
350	68.0	68.0	106.0	68.0	184.7	168.0	269.2
360	68.0	68.0	106.0	68.0	188.5	169.4	269.2
370	68.0	68.0	106.0	68.0	192.1	170.8	269.2
380	68.0	68.0	106.0	68.0	195.5	172.1	269.2
390	68.0	74.0	106.0	68.0	198.8	173.4	269.2
400	68.0	87.3	106.0	68.0	202.0	174.7	269.2
410	68.0	98.4	106.0	68.0	204.9	176.0	269.2
420	68.0	108.0	106.0	68.0	207.8	177.2	269.2
430	68.0	116.5	106.0	70.3	210.6	178.4	269.2
440	68.0	124.0	106.0	73.2	213.2	179.6	269.2
450	68.0	130.7	106.0	76.1	215.8	180.7	269.2
460	68.0	136.9	106.0	78.8	218.2	181.8	269.2
470	68.0	142.5	106.0	81.5	220.6	182.9	269.2
480	68.0	147.8	106.0	84.0	222.9	184.0	269.2
490	68.0	152.6	106.0	86.5	225.1	185.1	269.2

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
500	68.0	157.1	106.0	88.8	227.3	186.1	269.2
510	68.0	161.4	106.0	91.1	229.3	187.1	269.3
520	68.0	165.4	106.0	93.3	231.4	188.1	271.4
530	68.0	169.2	106.0	95.5	233.3	189.1	273.3
540	68.0	172.8	106.0	97.6	235.3	190.1	275.3
550	68.0	176.2	106.0	99.6	237.1	191.1	277.1
560	68.0	179.5	106.0	101.5	238.9	192.0	278.9
570	69.5	182.6	106.0	103.5	240.7	192.9	280.7
580	71.8	185.5	106.0	105.3	242.4	193.8	282.4
590	74.0	188.4	106.0	107.1	244.1	194.7	284.1
600	76.1	191.1	106.0	108.9	245.7	195.6	285.7
610	78.2	193.8	106.0	110.6	247.3	196.5	287.3
620	80.2	196.3	106.0	112.3	248.9	197.3	288.9
630	82.1	198.7	106.0	113.9	250.4	198.2	290.4
640	84.0	201.1	106.0	115.5	251.9	199.0	291.9
650	85.9	203.4	106.7	117.1	253.4	199.8	293.4
660	87.7	205.6	108.6	118.6	254.8	200.6	294.8
670	89.4	207.7	110.4	120.1	256.2	201.4	296.2
680	91.1	209.8	112.2	121.6	257.6	201.9	297.6
690	92.8	211.8	114.0	123.0	259.0	202.3	299.0
700	94.4	213.8	115.7	124.4	260.3	202.8	300.3
710	96.0	215.7	117.4	125.8	261.6	203.2	301.6
720	97.6	217.6	119.0	127.1	262.9	203.6	302.9
730	99.1	219.4	120.6	128.4	264.1	204.0	304.1
740	100.6	221.1	122.2	129.7	265.4	204.4	305.4
750	102.0	222.8	123.7	131.0	266.6	204.8	306.6
760	103.5	224.5	125.2	132.3	267.7	205.2	307.7

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
770	104.8	226.1	126.7	133.5	268.9	205.6	308.9
780	106.2	227.7	128.1	134.7	270.1	206.0	310.1
790	107.6	229.3	129.5	135.9	271.2	206.4	311.2
800	108.9	230.8	130.9	137.0	272.3	206.7	312.3
810	110.2	232.3	132.2	138.2	273.4	207.1	313.4
820	111.4	233.8	133.5	139.3	274.5	207.5	314.5
830	112.7	235.2	134.8	140.4	275.5	207.9	315.5
840	113.9	236.6	136.1	141.5	276.6	208.3	316.6
850	115.1	238.0	137.3	142.6	277.6	208.7	317.6
860	116.3	239.3	138.6	143.6	278.6	209.0	318.6
870	117.5	240.7	139.8	144.7	279.6	209.4	319.6
880	118.6	241.9	140.9	145.7	280.6	209.8	320.6
890	119.7	243.2	142.1	146.7	281.6	210.1	321.6
900	120.8	244.5	143.3	147.7	282.5	210.5	322.5
910	121.9	245.7	144.4	148.7	283.5	210.9	323.5
920	123.0	246.9	145.5	149.7	284.4	211.2	324.4
930	124.0	248.1	146.6	150.6	285.3	211.6	325.3
940	125.1	249.3	147.7	151.6	286.2	212.0	326.2
950	126.1	250.4	148.7	152.5	287.1	212.3	327.1
960	127.1	251.5	149.8	153.4	288.0	212.7	328.0
970	128.1	252.6	150.8	154.3	288.9	213.0	328.9
980	129.1	253.7	151.8	155.2	289.7	213.4	329.7
990	130.0	254.8	152.8	156.1	290.6	213.7	330.6
1000	131.0	255.9	153.8	157.0	291.4	214.1	331.4
1010	131.9	256.9	154.7	157.8	292.3	214.4	332.3
1020	132.9	257.9	155.7	158.7	293.1	214.8	333.1
1030	133.8	258.9	156.6	159.5	293.9	215.1	333.9

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1040	134.7	259.9	157.6	160.4	294.7	215.4	334.7
1050	135.6	260.9	158.5	161.2	295.5	215.8	335.5
1060	136.5	261.9	159.4	162.0	296.3	216.1	336.3
1070	137.3	262.8	160.3	162.8	297.1	216.5	337.1
1080	138.2	263.8	161.2	163.6	297.8	216.8	337.8
1090	139.0	264.7	162.0	164.4	298.6	217.1	338.6
1100	139.9	265.6	162.9	165.1	299.3	217.5	339.3
1110	140.7	266.5	163.7	165.9	300.1	217.8	340.1
1120	141.5	267.4	164.6	166.7	300.8	218.1	340.8
1130	142.3	268.3	165.4	167.4	301.5	218.4	341.5
1140	143.1	269.2	166.2	168.1	302.2	218.8	342.2
1150	143.9	270.0	167.0	168.9	303.0	219.1	343.0
1160	144.7	270.9	167.8	169.6	303.7	219.4	343.7
1170	145.5	271.7	168.6	170.3	304.4	219.7	344.4
1180	146.2	272.6	169.4	171.0	305.0	220.0	345.0
1190	147.0	273.4	170.2	171.7	305.7	220.4	345.7
1200	147.7	274.2	170.9	172.4	306.4	220.7	346.4
1210	148.5	275.0	171.7	173.1	307.1	221.0	347.1
1220	149.2	275.8	172.4	173.8	307.7	221.3	347.7
1230	149.9	276.6	173.2	174.5	308.4	221.6	348.4
1240	150.6	277.3	173.9	175.1	309.0	221.9	349.0
1250	151.3	278.1	174.6	175.8	309.7	222.2	349.7
1260	152.0	278.8	175.4	176.5	310.3	222.5	350.3
1270	152.7	279.6	176.1	177.1	311.0	222.8	351.0
1280	153.4	280.3	176.8	177.8	311.6	223.1	351.6
1290	154.1	281.1	177.5	178.4	312.2	223.4	352.2
1300	154.8	281.8	178.1	179.0	312.8	223.7	352.8

TABLE 4-4. Hatch Unit 1 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-1 THROUGH 4-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1310	155.4	282.5	178.8	179.6	313.4	224.0	353.4
1320	156.1	283.2	179.5	180.3	314.0	224.3	354.0
1330	156.8	283.9	180.2	180.9	314.6	224.6	354.6
1340	157.4	284.6	180.8	181.5	315.2	224.9	355.2
1350	158.1	285.3	181.5	182.1	315.8	225.2	355.8
1360	158.7	286.0	182.1	182.7	316.4	225.5	356.4
1370	159.3	286.7	182.8	183.3	317.0	225.8	357.0
1380	159.9	287.3	183.4	183.9	317.6	226.1	357.6
1390	160.6	288.0	184.0	184.5	318.1	226.4	358.1
1400	161.2	288.6	184.7	185.0	318.7	226.7	358.7

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
0	68.0	68.0	90.0	68.0	68.0	90.0	90.0
10	68.0	68.0	90.0	68.0	68.0	90.0	90.0
20	68.0	68.0	90.0	68.0	68.0	90.0	90.0
30	68.0	68.0	90.0	68.0	68.0	90.0	90.0
40	68.0	68.0	90.0	68.0	68.0	90.0	90.5
50	68.0	68.0	90.0	68.0	68.0	90.0	101.2
60	68.0	68.0	90.0	68.0	68.0	90.0	109.9
70	68.0	68.0	90.0	68.0	68.0	90.0	117.1
80	68.0	68.0	90.0	68.0	68.0	90.0	123.4
90	68.0	68.0	90.0	68.0	68.0	90.0	128.7
100	68.0	68.0	90.0	68.0	68.0	93.5	133.5
110	68.0	68.0	90.0	68.0	68.0	97.9	137.9
120	68.0	68.0	90.0	68.0	68.0	102.1	142.1
130	68.0	68.0	90.0	68.0	68.0	106.1	146.1
140	68.0	68.0	90.0	68.0	68.0	109.6	149.6
150	68.0	68.0	90.0	68.0	68.0	112.8	152.8
160	68.0	68.0	90.0	68.0	68.0	115.8	155.8
170	68.0	68.0	90.0	68.0	68.0	118.8	158.8
180	68.0	68.0	90.0	68.0	68.0	121.6	161.6
190	68.0	68.0	90.0	68.0	68.0	124.2	164.2
200	68.0	68.0	90.0	68.0	68.0	126.6	166.6
210	68.0	68.0	90.0	68.0	68.0	128.9	168.9
220	68.0	68.0	90.0	68.0	68.0	131.2	171.2
230	68.0	68.0	90.0	68.0	68.0	133.4	173.4
240	68.0	68.0	90.0	68.0	68.0	135.4	175.4
250	68.0	68.0	90.0	68.0	68.0	137.4	177.4
260	68.0	68.0	90.0	68.0	68.0	139.3	179.3

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
270	68.0	68.0	90.0	68.0	68.0	141.1	181.1
280	68.0	68.0	90.0	68.0	68.0	143.0	183.0
290	68.0	68.0	90.0	68.0	68.0	144.7	184.7
300	68.0	68.0	90.0	68.0	68.0	146.3	186.3
310	68.0	68.0	90.0	68.0	71.5	148.0	188.0
312.5	68.0	68.0	90.0	68.0	72.9	148.3	188.3
312.5	68.0	68.0	120.0	68.0	72.9	150.0	190.0
320	68.0	68.0	120.0	68.0	76.8	150.0	190.0
330	68.0	68.0	120.0	70.1	81.6	151.1	191.1
340	68.0	68.0	120.0	75.4	86.1	152.6	192.6
350	68.0	68.0	120.0	80.2	94.0	154.0	194.0
360	68.0	68.0	120.0	84.8	97.9	155.4	195.4
370	68.0	68.0	120.0	89.0	101.6	156.8	196.8
380	68.0	68.0	120.0	93.1	105.1	158.1	198.1
390	68.0	68.0	120.0	96.9	108.5	159.4	199.4
400	68.0	68.0	120.0	100.5	111.6	160.7	200.7
410	68.0	68.0	120.0	103.9	114.7	162.0	202.0
420	68.0	68.0	120.0	107.2	117.6	163.2	203.2
430	68.0	68.0	120.0	110.3	120.4	164.4	204.4
440	70.1	68.0	120.0	113.2	123.1	165.6	205.6
450	74.1	68.0	120.0	116.1	125.6	166.7	206.7
460	77.8	68.0	120.0	118.8	128.1	167.8	207.8
470	81.4	68.0	120.0	121.5	130.5	168.9	208.9
480	84.8	68.0	120.0	124.0	132.9	170.0	210.0
490	88.0	68.0	120.0	126.5	135.1	171.1	211.1
500	91.1	68.0	120.0	128.8	137.3	172.1	212.1
510	94.0	72.2	120.0	131.1	139.4	173.1	213.1

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
520	96.9	76.2	120.0	133.3	141.4	174.1	214.1
530	99.6	80.0	120.0	135.5	143.4	175.1	215.1
540	102.2	83.6	120.0	137.6	145.3	176.1	216.1
550	104.7	87.0	120.0	139.6	147.2	177.1	217.1
560	107.2	90.3	120.0	141.5	149.1	178.0	218.0
570	109.5	93.4	120.0	143.5	150.8	178.9	218.9
580	111.8	96.3	120.0	145.3	152.6	179.8	219.8
590	114.0	99.2	120.0	147.1	154.3	180.7	220.7
600	116.1	101.9	120.0	148.9	155.9	181.6	221.6
610	118.2	104.5	120.0	150.6	157.5	182.5	222.5
620	120.2	107.1	120.0	152.3	159.1	183.3	223.3
630	122.1	109.5	120.0	153.9	160.7	184.2	224.2
640	124.0	111.9	120.0	155.5	162.2	185.0	225.0
650	125.9	114.2	120.0	157.1	163.6	185.8	225.8
660	127.7	116.4	120.0	158.6	165.1	186.6	226.6
670	129.4	118.5	120.0	160.1	166.5	187.4	227.4
680	131.1	120.6	120.0	161.6	167.9	187.9	227.9
690	132.8	122.6	120.0	163.0	169.2	188.3	228.3
700	134.4	124.6	120.0	164.4	170.6	188.8	228.8
710	136.0	126.5	120.0	165.8	171.9	189.2	229.2
720	137.6	128.3	120.0	167.1	173.2	189.6	229.6
730	139.1	130.1	120.0	168.4	174.4	190.0	230.0
740	140.6	131.9	120.0	169.7	175.7	190.4	230.4
750	142.0	133.6	120.0	171.0	176.9	190.8	230.8
760	143.5	135.3	120.0	172.3	178.1	191.2	231.2
770	144.8	136.9	120.0	173.5	179.3	191.6	231.6
780	146.2	138.5	120.0	174.7	180.4	192.0	232.0

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
790	147.6	140.1	120.0	175.9	181.5	192.4	232.4
800	148.9	141.6	120.0	177.0	182.7	192.7	232.7
810	150.2	143.1	120.0	178.2	183.8	193.1	233.1
820	151.4	144.5	120.0	179.3	184.8	193.5	233.5
830	152.7	146.0	120.8	180.4	185.9	193.9	233.9
840	153.9	147.4	122.1	181.5	187.0	194.3	234.3
850	155.1	148.7	123.3	182.6	188.0	194.7	234.7
860	156.3	150.1	124.6	183.6	189.0	195.0	235.0
870	157.5	151.4	125.8	184.7	190.0	195.4	235.4
880	158.6	152.7	126.9	185.7	191.0	195.8	235.8
890	159.7	154.0	128.1	186.7	192.0	196.1	236.1
900	160.8	155.2	129.3	187.7	192.9	196.5	236.5
910	161.9	156.5	130.4	188.7	193.9	196.9	236.9
920	163.0	157.7	131.5	189.7	194.8	197.2	237.2
930	164.0	158.8	132.6	190.6	195.8	197.6	237.6
940	165.1	160.0	133.7	191.6	196.7	198.0	238.0
950	166.1	161.2	134.7	192.5	197.6	198.3	238.3
960	167.1	162.3	135.8	193.4	198.5	198.7	238.7
970	168.1	163.4	136.8	194.3	199.3	199.0	239.3
980	169.1	164.5	137.8	195.2	200.2	199.4	240.2
990	170.0	165.6	138.8	196.1	201.0	199.7	241.0
1000	171.0	166.6	139.8	197.0	201.9	200.1	241.9
1010	171.9	167.7	140.7	197.8	202.7	200.4	242.7
1020	172.9	168.7	141.7	198.7	203.5	200.8	243.5
1030	173.8	169.7	142.6	199.5	204.4	201.1	244.4
1040	174.7	170.7	143.6	200.4	205.2	201.4	245.2
1050	175.6	171.7	144.5	201.2	206.0	201.8	246.0

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1060	176.5	172.6	145.4	202.0	206.7	202.1	246.7
1070	177.3	173.6	146.3	202.8	207.5	202.5	247.5
1080	178.2	174.5	147.2	203.6	208.3	202.8	248.3
1090	179.0	175.5	148.0	204.4	209.1	203.1	249.1
1100	179.9	176.4	148.9	205.1	209.8	203.5	249.8
1110	180.7	177.3	149.7	205.9	210.6	203.8	250.6
1120	181.5	178.2	150.6	206.7	211.3	204.1	251.3
1130	182.3	179.1	151.4	207.4	212.0	204.4	252.0
1140	183.1	179.9	152.2	208.1	212.7	204.8	252.7
1150	183.9	180.8	153.0	208.9	213.4	205.1	253.4
1160	184.7	181.6	153.8	209.6	214.2	205.4	254.2
1170	185.5	182.5	154.6	210.3	214.9	205.7	254.9
1180	186.2	183.3	155.4	211.0	215.5	206.0	255.5
1190	187.0	184.1	156.2	211.7	216.2	206.4	256.2
1200	187.7	184.9	156.9	212.4	216.9	206.7	256.9
1210	188.5	185.7	157.7	213.1	217.6	207.0	257.6
1220	189.2	186.5	158.4	213.8	218.2	207.3	258.2
1230	189.9	187.3	159.2	214.5	218.9	207.6	258.9
1240	190.6	188.1	159.9	215.1	219.6	207.9	259.6
1250	191.3	188.8	160.6	215.8	220.2	208.2	260.2
1260	192.0	189.6	161.4	216.5	220.8	208.5	260.8
1270	192.7	190.3	162.1	217.1	221.5	208.8	261.5
1280	193.4	191.1	162.8	217.8	222.1	209.1	262.1
1290	194.1	191.8	163.5	218.4	222.7	209.4	262.7
1300	194.8	192.5	164.1	219.0	223.3	209.7	263.3
1310	195.4	193.3	164.8	219.6	224.0	210.0	264.0
1320	196.1	194.0	165.5	220.3	224.6	210.3	264.6

TABLE 4-5. Hatch Unit 2 P-T Curve Values for 54 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES 4-4 THROUGH 4-6)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	54 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	54 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	54 EFPY RPV CURVE C (°F)
1330	196.8	194.7	166.2	220.9	225.2	210.6	265.2
1340	197.4	195.4	166.8	221.5	225.8	210.9	265.8
1350	198.1	196.1	167.5	222.1	226.4	211.2	266.4
1360	198.7	196.7	168.1	222.7	226.9	211.5	266.9
1370	199.3	197.4	168.8	223.3	227.5	211.8	267.5
1380	199.9	198.1	169.4	223.9	228.1	212.1	268.1
1390	200.6	198.7	170.0	224.5	228.7	212.4	268.7
1400	201.2	199.4	170.7	225.0	229.2	212.7	269.2

5. REFERENCES

[1] "Fracture Toughness Requirements", Appendix G to Part 50 of Title 10 of the Code of Federal Regulations, December 1995.

[2] Carey, R. G., "Extended Power Uprate Evaluation Task Report for Edwin I. Hatch Plant Units 1 & 2, Revised Impact on Vessel Fracture Toughness," GE-NE-A13-00402-9, March 1998.

[3] "Radiation Embrittlement of Reactor Vessel Materials", USNRC Regulatory Guide 1.99, Revision 2, May 1988

[4] H. S. Mehta, T. A. Caine, and S. E. Plaxton, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 through BWR/6 Vessels, Rev. 1," GENE, San Jose, CA, February, 1994, (NEDO-32205-A).

[5] "PVRC Recommendations on Toughness Requirements for Ferritic Materials", Welding Research Council Bulletin 175, August 1972.

[6] Frew, B. D., "Plant Hatch Unit 1 RPV Surveillance Materials Testing and Analysis", GE-NE-B1100691-01R1, March 1997.

[7] Caine, T. A. "E.I. Hatch Nuclear Power Station Unit 2 Vessel Surveillance Materials Testing and Fracture Toughness Analysis,", SASR 90-104, May 1991.

[8] Protection Against Non-Ductile Failure", Appendix G to Section XI of the 1989 ASME Boiler & Pressure Vessel Code.

[9] Design Stress Intensity Values, Allowable Stresses, Material Properties, and Design Fatigue Curves", Section III Appendix I of the 1989 ASME Boiler and Pressure Vessel Code.

APPENDIX A

HATCH UNIT 1 P-T CURVES

VALID TO 36 EFPY

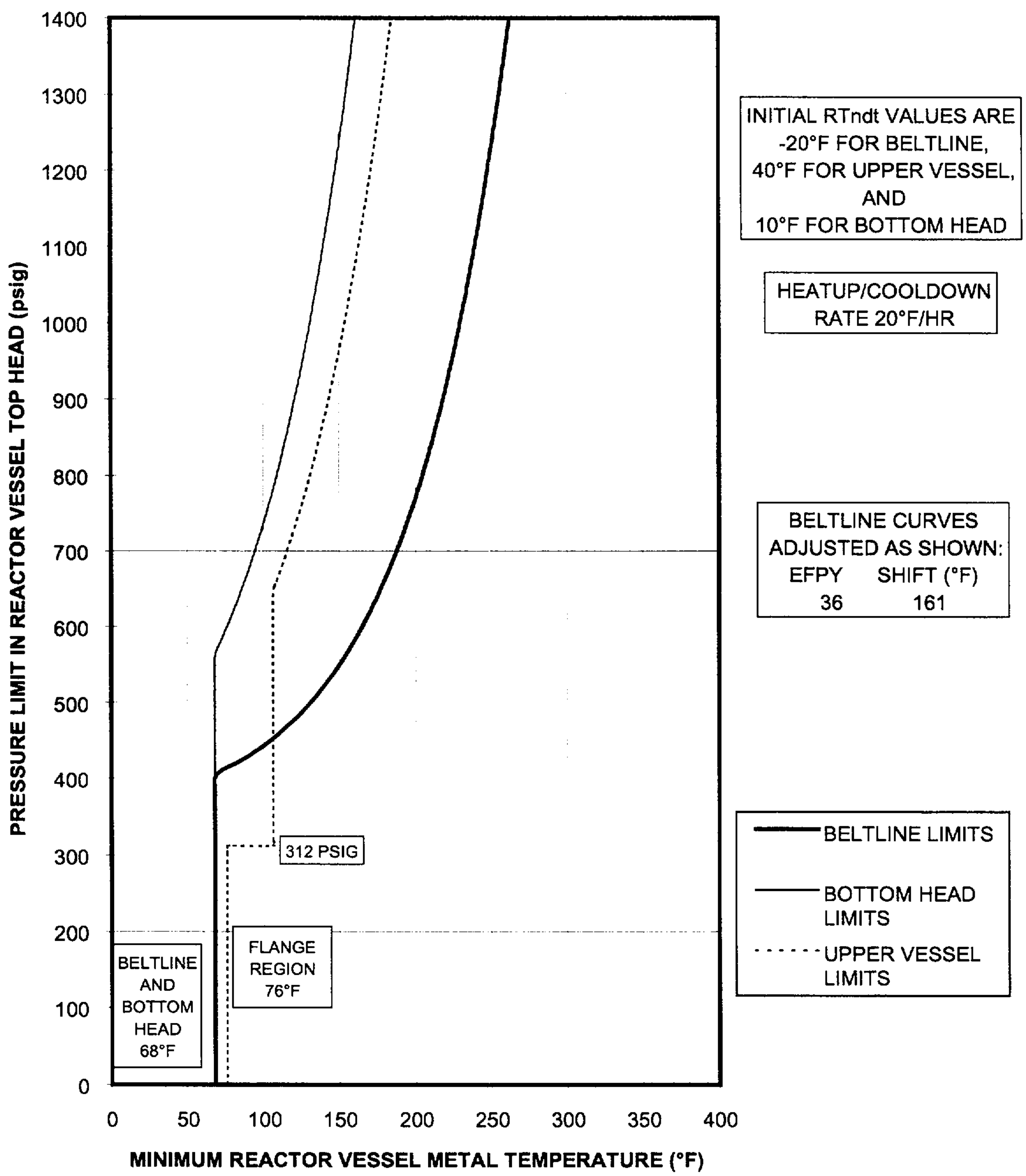


Figure A-1: P-T Curve for Unit 1 (Curve A)

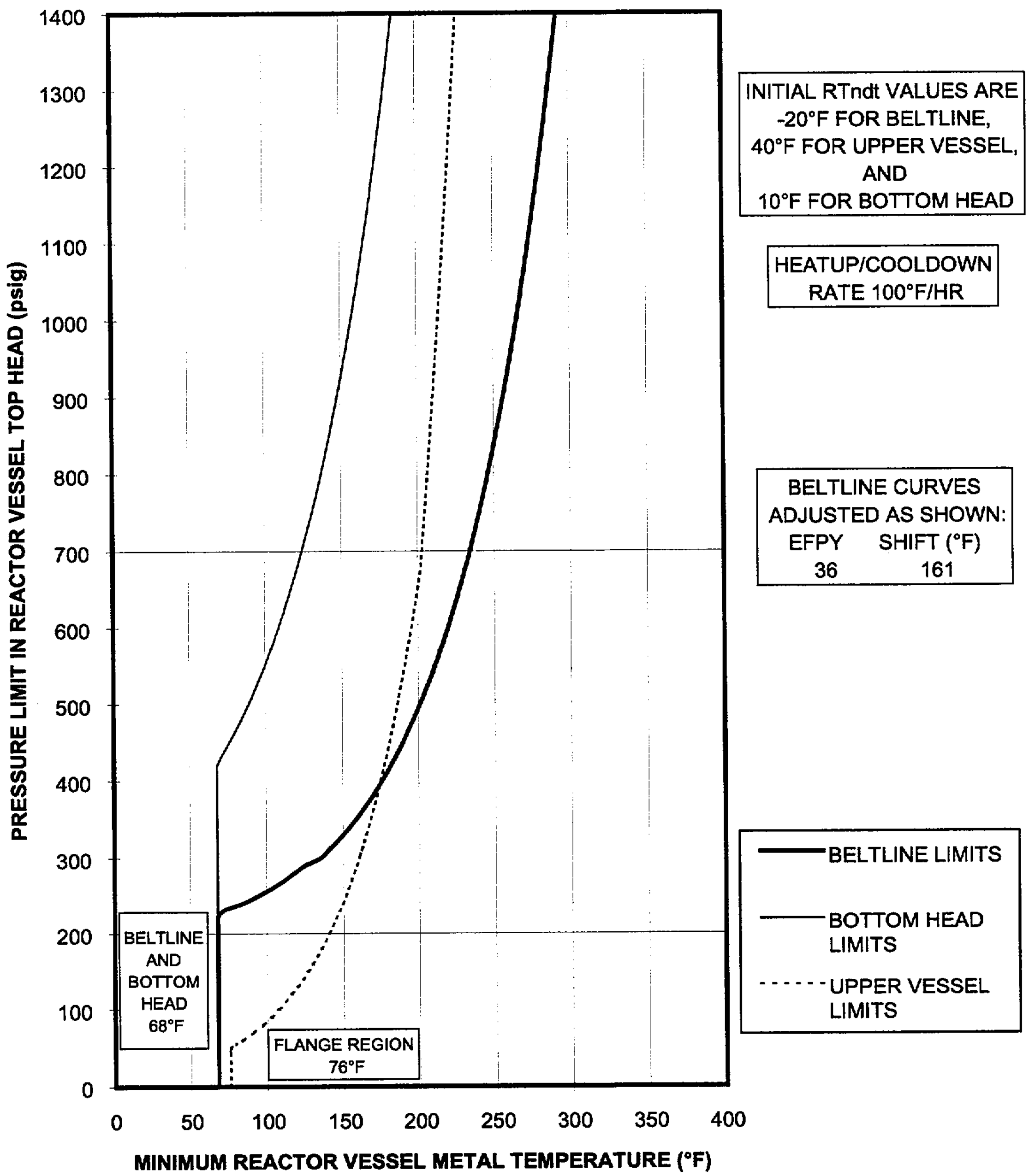


Figure A-2: P-T Curve for Unit 1 (Curve B)

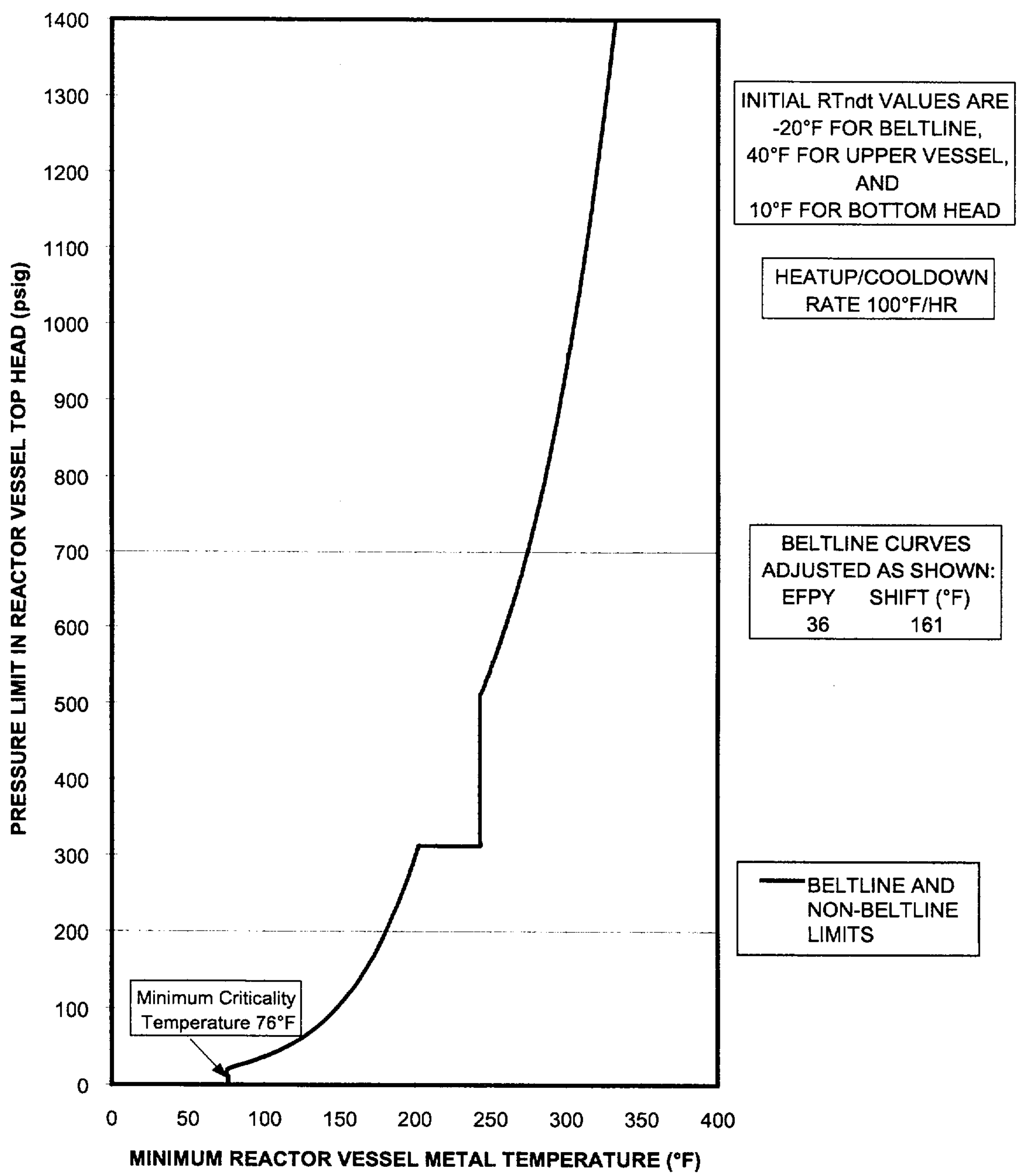


Figure A-3: P-T Curve for Unit 1 (Curve C)

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.0	145.2	185.2
230	68.0	68.0	76.0	68.0	71.2	147.4	187.4
240	68.0	68.0	76.0	68.0	83.6	149.4	189.4
250	68.0	68.0	76.0	68.0	94.1	151.4	191.4
260	68.0	68.0	76.0	68.0	103.2	153.3	193.3

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
270	68.0	68.0	76.0	68.0	111.3	155.1	195.1
280	68.0	68.0	76.0	68.0	118.5	157.0	197.0
290	68.0	68.0	76.0	68.0	125.0	158.7	198.7
300	68.0	68.0	76.0	68.0	135.3	160.3	200.3
310	68.0	68.0	76.0	68.0	140.6	162.0	202.0
312.5	68.0	68.0	76.0	68.0	141.9	162.3	202.3
312.5	68.0	68.0	106.0	68.0	141.9	162.3	243.0
320	68.0	68.0	106.0	68.0	145.5	163.5	243.0
330	68.0	68.0	106.0	68.0	150.1	165.1	243.0
340	68.0	68.0	106.0	68.0	154.4	166.6	243.0
350	68.0	68.0	106.0	68.0	158.5	168.0	243.0
360	68.0	68.0	106.0	68.0	162.3	169.4	243.0
370	68.0	68.0	106.0	68.0	165.9	170.8	243.0
380	68.0	68.0	106.0	68.0	169.3	172.1	243.0
390	68.0	68.0	106.0	68.0	172.6	173.4	243.0
400	68.0	68.0	106.0	68.0	175.8	174.7	243.0
410	68.0	72.2	106.0	68.0	178.7	176.0	243.0
420	68.0	81.8	106.0	68.0	181.6	177.2	243.0
430	68.0	90.3	106.0	70.3	184.4	178.4	243.0
440	68.0	97.8	106.0	73.2	187.0	179.6	243.0
450	68.0	104.5	106.0	76.1	189.6	180.7	243.0
460	68.0	110.7	106.0	78.8	192.0	181.8	243.0
470	68.0	116.3	106.0	81.5	194.4	182.9	243.0
480	68.0	121.6	106.0	84.0	196.7	184.0	243.0
490	68.0	126.4	106.0	86.5	198.9	185.1	243.0
500	68.0	130.9	106.0	88.8	201.1	186.1	243.0
510	68.0	135.2	106.0	91.1	203.1	187.1	243.1

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
520	68.0	139.2	106.0	93.3	205.2	188.1	245.2
530	68.0	143.0	106.0	95.5	207.1	189.1	247.1
540	68.0	146.6	106.0	97.6	209.1	190.1	249.1
550	68.0	150.0	106.0	99.6	210.9	191.1	250.9
560	68.0	153.3	106.0	101.5	212.7	192.0	252.7
570	69.5	156.4	106.0	103.5	214.5	192.9	254.5
580	71.8	159.3	106.0	105.3	216.2	193.8	256.2
590	74.0	162.2	106.0	107.1	217.9	194.7	257.9
600	76.1	164.9	106.0	108.9	219.5	195.6	259.5
610	78.2	167.6	106.0	110.6	221.1	196.5	261.1
620	80.2	170.1	106.0	112.3	222.7	197.3	262.7
630	82.1	172.5	106.0	113.9	224.2	198.2	264.2
640	84.0	174.9	106.0	115.5	225.7	199.0	265.7
650	85.9	177.2	106.7	117.1	227.2	199.8	267.2
660	87.7	179.4	108.6	118.6	228.6	200.6	268.6
670	89.4	181.5	110.4	120.1	230.0	201.4	270.0
680	91.1	183.6	112.2	121.6	231.4	201.9	271.4
690	92.8	185.6	114.0	123.0	232.8	202.3	272.8
700	94.4	187.6	115.7	124.4	234.1	202.8	274.1
710	96.0	189.5	117.4	125.8	235.4	203.2	275.4
720	97.6	191.4	119.0	127.1	236.7	203.6	276.7
730	99.1	193.2	120.6	128.4	237.9	204.0	277.9
740	100.6	194.9	122.2	129.7	239.2	204.4	279.2
750	102.0	196.6	123.7	131.0	240.4	204.8	280.4
760	103.5	198.3	125.2	132.3	241.5	205.2	281.5
770	104.8	199.9	126.7	133.5	242.7	205.6	282.7
780	106.2	201.5	128.1	134.7	243.9	206.0	283.9

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
790	107.6	203.1	129.5	135.9	245.0	206.4	285.0
800	108.9	204.6	130.9	137.0	246.1	206.7	286.1
810	110.2	206.1	132.2	138.2	247.2	207.1	287.2
820	111.4	207.6	133.5	139.3	248.3	207.5	288.3
830	112.7	209.0	134.8	140.4	249.3	207.9	289.3
840	113.9	210.4	136.1	141.5	250.4	208.3	290.4
850	115.1	211.8	137.3	142.6	251.4	208.7	291.4
860	116.3	213.1	138.6	143.6	252.4	209.0	292.4
870	117.5	214.5	139.8	144.7	253.4	209.4	293.4
880	118.6	215.7	140.9	145.7	254.4	209.8	294.4
890	119.7	217.0	142.1	146.7	255.4	210.1	295.4
900	120.8	218.3	143.3	147.7	256.3	210.5	296.3
910	121.9	219.5	144.4	148.7	257.3	210.9	297.3
920	123.0	220.7	145.5	149.7	258.2	211.2	298.2
930	124.0	221.9	146.6	150.6	259.1	211.6	299.1
940	125.1	223.1	147.7	151.6	260.0	212.0	300.0
950	126.1	224.2	148.7	152.5	260.9	212.3	300.9
960	127.1	225.3	149.8	153.4	261.8	212.7	301.8
970	128.1	226.4	150.8	154.3	262.7	213.0	302.7
980	129.1	227.5	151.8	155.2	263.5	213.4	303.5
990	130.0	228.6	152.8	156.1	264.4	213.7	304.4
1000	131.0	229.7	153.8	157.0	265.2	214.1	305.2
1010	131.9	230.7	154.7	157.8	266.1	214.4	306.1
1020	132.9	231.7	155.7	158.7	266.9	214.8	306.9
1030	133.8	232.7	156.6	159.5	267.7	215.1	307.7
1040	134.7	233.7	157.6	160.4	268.5	215.4	308.5
1050	135.6	234.7	158.5	161.2	269.3	215.8	309.3

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
1060	136.5	235.7	159.4	162.0	270.1	216.1	310.1
1070	137.3	236.6	160.3	162.8	270.9	216.5	310.9
1080	138.2	237.6	161.2	163.6	271.6	216.8	311.6
1090	139.0	238.5	162.0	164.4	272.4	217.1	312.4
1100	139.9	239.4	162.9	165.1	273.1	217.5	313.1
1110	140.7	240.3	163.7	165.9	273.9	217.8	313.9
1120	141.5	241.2	164.6	166.7	274.6	218.1	314.6
1130	142.3	242.1	165.4	167.4	275.3	218.4	315.3
1140	143.1	243.0	166.2	168.1	276.0	218.8	316.0
1150	143.9	243.8	167.0	168.9	276.8	219.1	316.8
1160	144.7	244.7	167.8	169.6	277.5	219.4	317.5
1170	145.5	245.5	168.6	170.3	278.2	219.7	318.2
1180	146.2	246.4	169.4	171.0	278.8	220.0	318.8
1190	147.0	247.2	170.2	171.7	279.5	220.4	319.5
1200	147.7	248.0	170.9	172.4	280.2	220.7	320.2
1210	148.5	248.8	171.7	173.1	280.9	221.0	320.9
1220	149.2	249.6	172.4	173.8	281.5	221.3	321.5
1230	149.9	250.4	173.2	174.5	282.2	221.6	322.2
1240	150.6	251.1	173.9	175.1	282.8	221.9	322.8
1250	151.3	251.9	174.6	175.8	283.5	222.2	323.5
1260	152.0	252.6	175.4	176.5	284.1	222.5	324.1
1270	152.7	253.4	176.1	177.1	284.8	222.8	324.8
1280	153.4	254.1	176.8	177.8	285.4	223.1	325.4
1290	154.1	254.9	177.5	178.4	286.0	223.4	326.0
1300	154.8	255.6	178.1	179.0	286.6	223.7	326.6
1310	155.4	256.3	178.8	179.6	287.2	224.0	327.2
1320	156.1	257.0	179.5	180.3	287.8	224.3	327.8

TABLE A-1. Hatch Unit 1 P-T Curve Values for 36 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES A-1 THROUGH A-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	36 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	36 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	36 EFPY RPV CURVE C (°F)
1330	156.8	257.7	180.2	180.9	288.4	224.6	328.4
1340	157.4	258.4	180.8	181.5	289.0	224.9	329.0
1350	158.1	259.1	181.5	182.1	289.6	225.2	329.6
1360	158.7	259.8	182.1	182.7	290.2	225.5	330.2
1370	159.3	260.5	182.8	183.3	290.8	225.8	330.8
1380	159.9	261.1	183.4	183.9	291.4	226.1	331.4
1390	160.6	261.8	184.0	184.5	291.9	226.4	331.9
1400	161.2	262.4	184.7	185.0	292.5	226.7	332.5

APPENDIX B

HATCH UNIT 1 P-T CURVES

VALID TO 40 EFPY

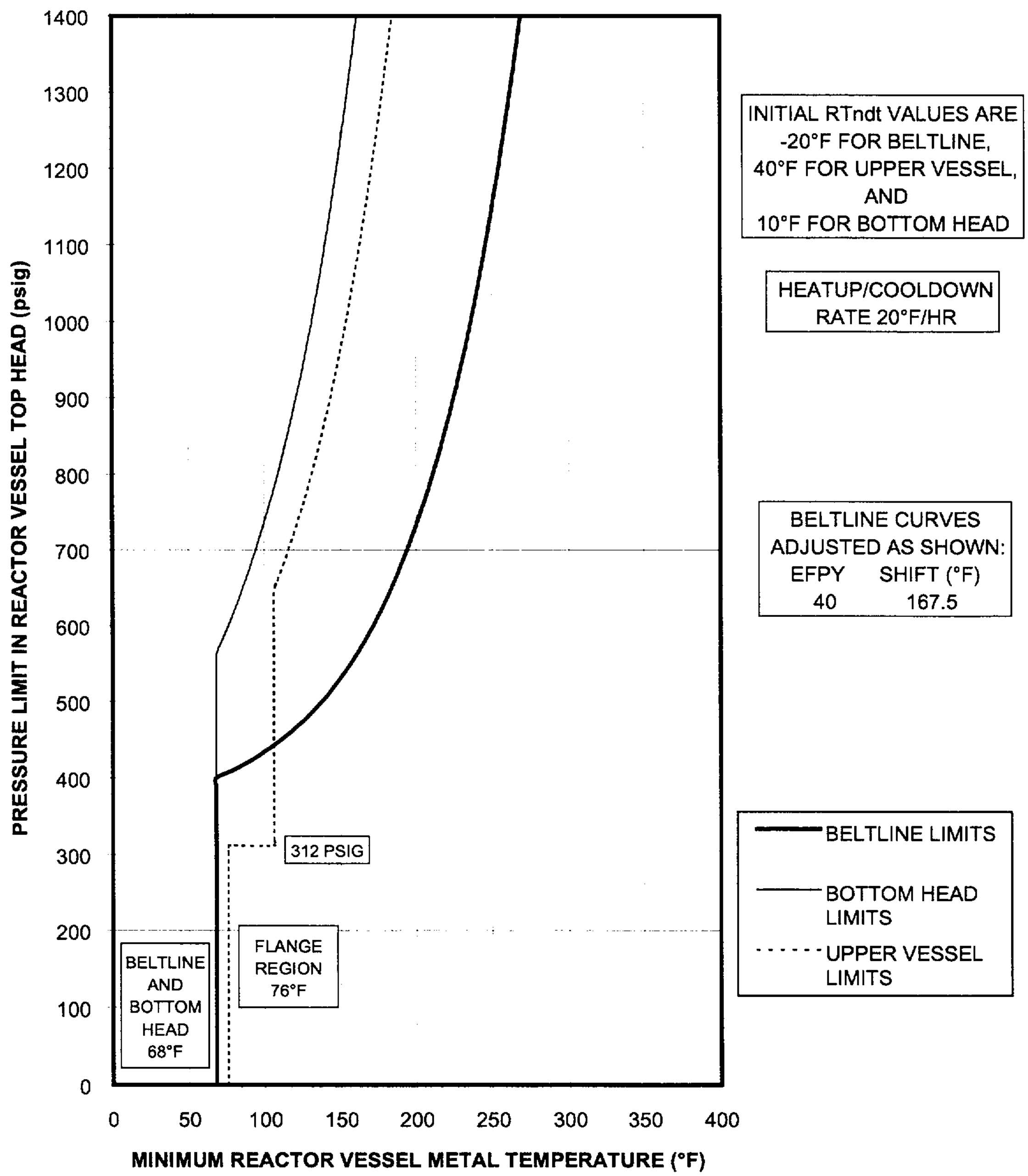


Figure B-1: P-T Curve for Unit 1 (Curve A)

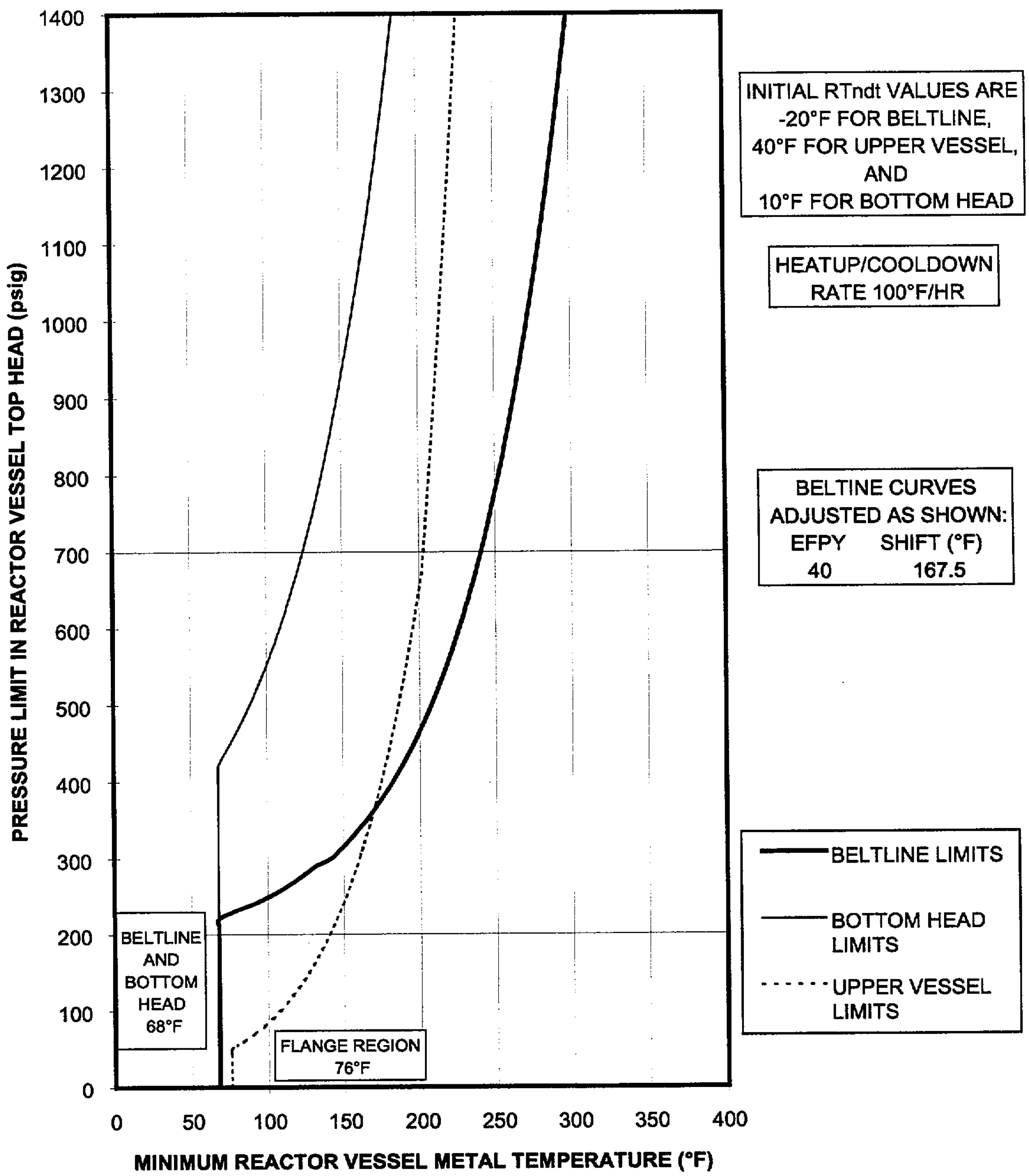


Figure B-2: P-T Curve for Unit 1 (Curve B)

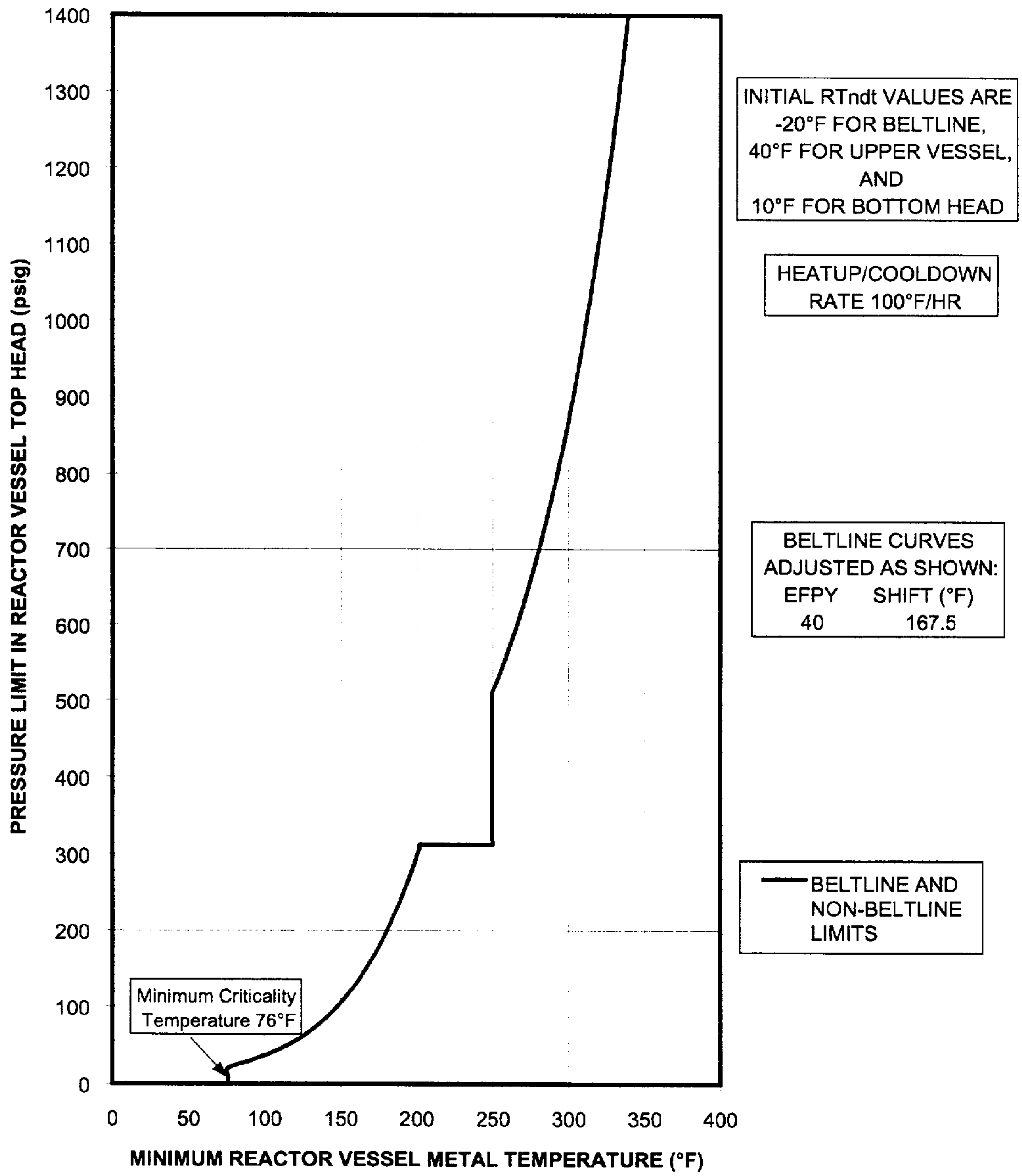


Figure B-3: P-T Curve for Unit 1 (Curve C)

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.0	145.2	185.2
230	68.0	68.0	76.0	68.0	77.7	147.4	187.4
240	68.0	68.0	76.0	68.0	90.1	149.4	189.4
250	68.0	68.0	76.0	68.0	100.6	151.4	191.4

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	109.7	153.3	193.3
270	68.0	68.0	76.0	68.0	117.8	155.1	195.1
280	68.0	68.0	76.0	68.0	125.0	157.0	197.0
290	68.0	68.0	76.0	68.0	131.5	158.7	198.7
300	68.0	68.0	76.0	68.0	141.8	160.3	200.3
310	68.0	68.0	76.0	68.0	147.1	162.0	202.0
312.5	68.0	68.0	76.0	68.0	148.4	162.3	202.3
312.5	68.0	68.0	106.0	68.0	148.4	162.3	249.5
320	68.0	68.0	106.0	68.0	152.0	163.5	249.5
330	68.0	68.0	106.0	68.0	156.6	165.1	249.5
340	68.0	68.0	106.0	68.0	160.9	166.6	249.5
350	68.0	68.0	106.0	68.0	165.0	168.0	249.5
360	68.0	68.0	106.0	68.0	168.8	169.4	249.5
370	68.0	68.0	106.0	68.0	172.4	170.8	249.5
380	68.0	68.0	106.0	68.0	175.8	172.1	249.5
390	68.0	68.0	106.0	68.0	179.1	173.4	249.5
400	68.0	68.0	106.0	68.0	182.3	174.7	249.5
410	68.0	78.7	106.0	68.0	185.2	176.0	249.5
420	68.0	88.3	106.0	68.0	188.1	177.2	249.5
430	68.0	96.8	106.0	70.3	190.9	178.4	249.5
440	68.0	104.3	106.0	73.2	193.5	179.6	249.5
450	68.0	111.0	106.0	76.1	196.1	180.7	249.5
460	68.0	117.2	106.0	78.8	198.5	181.8	249.5
470	68.0	122.8	106.0	81.5	200.9	182.9	249.5
480	68.0	128.1	106.0	84.0	203.2	184.0	249.5
490	68.0	132.9	106.0	86.5	205.4	185.1	249.5
500	68.0	137.4	106.0	88.8	207.6	186.1	249.5

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
510	68.0	141.7	106.0	91.1	209.6	187.1	249.6
520	68.0	145.7	106.0	93.3	211.7	188.1	251.7
530	68.0	149.5	106.0	95.5	213.6	189.1	253.6
540	68.0	153.1	106.0	97.6	215.6	190.1	255.6
550	68.0	156.5	106.0	99.6	217.4	191.1	257.4
560	68.0	159.8	106.0	101.5	219.2	192.0	259.2
570	69.5	162.9	106.0	103.5	221.0	192.9	261.0
580	71.8	165.8	106.0	105.3	222.7	193.8	262.7
590	74.0	168.7	106.0	107.1	224.4	194.7	264.4
600	76.1	171.4	106.0	108.9	226.0	195.6	266.0
610	78.2	174.1	106.0	110.6	227.6	196.5	267.6
620	80.2	176.6	106.0	112.3	229.2	197.3	269.2
630	82.1	179.0	106.0	113.9	230.7	198.2	270.7
640	84.0	181.4	106.0	115.5	232.2	199.0	272.2
650	85.9	183.7	106.7	117.1	233.7	199.8	273.7
660	87.7	185.9	108.6	118.6	235.1	200.6	275.1
670	89.4	188.0	110.4	120.1	236.5	201.4	276.5
680	91.1	190.1	112.2	121.6	237.9	201.9	277.9
690	92.8	192.1	114.0	123.0	239.3	202.3	279.3
700	94.4	194.1	115.7	124.4	240.6	202.8	280.6
710	96.0	196.0	117.4	125.8	241.9	203.2	281.9
720	97.6	197.9	119.0	127.1	243.2	203.6	283.2
730	99.1	199.7	120.6	128.4	244.4	204.0	284.4
740	100.6	201.4	122.2	129.7	245.7	204.4	285.7
750	102.0	203.1	123.7	131.0	246.9	204.8	286.9
760	103.5	204.8	125.2	132.3	248.0	205.2	288.0
770	104.8	206.4	126.7	133.5	249.2	205.6	289.2

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
780	106.2	208.0	128.1	134.7	250.4	206.0	290.4
790	107.6	209.6	129.5	135.9	251.5	206.4	291.5
800	108.9	211.1	130.9	137.0	252.6	206.7	292.6
810	110.2	212.6	132.2	138.2	253.7	207.1	293.7
820	111.4	214.1	133.5	139.3	254.8	207.5	294.8
830	112.7	215.5	134.8	140.4	255.8	207.9	295.8
840	113.9	216.9	136.1	141.5	256.9	208.3	296.9
850	115.1	218.3	137.3	142.6	257.9	208.7	297.9
860	116.3	219.6	138.6	143.6	258.9	209.0	298.9
870	117.5	221.0	139.8	144.7	259.9	209.4	299.9
880	118.6	222.2	140.9	145.7	260.9	209.8	300.9
890	119.7	223.5	142.1	146.7	261.9	210.1	301.9
900	120.8	224.8	143.3	147.7	262.8	210.5	302.8
910	121.9	226.0	144.4	148.7	263.8	210.9	303.8
920	123.0	227.2	145.5	149.7	264.7	211.2	304.7
930	124.0	228.4	146.6	150.6	265.6	211.6	305.6
940	125.1	229.6	147.7	151.6	266.5	212.0	306.5
950	126.1	230.7	148.7	152.5	267.4	212.3	307.4
960	127.1	231.8	149.8	153.4	268.3	212.7	308.3
970	128.1	232.9	150.8	154.3	269.2	213.0	309.2
980	129.1	234.0	151.8	155.2	270.0	213.4	310.0
990	130.0	235.1	152.8	156.1	270.9	213.7	310.9
1000	131.0	236.2	153.8	157.0	271.7	214.1	311.7
1010	131.9	237.2	154.7	157.8	272.6	214.4	312.6
1020	132.9	238.2	155.7	158.7	273.4	214.8	313.4
1030	133.8	239.2	156.6	159.5	274.2	215.1	314.2
1040	134.7	240.2	157.6	160.4	275.0	215.4	315.0

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
1050	135.6	241.2	158.5	161.2	275.8	215.8	315.8
1060	136.5	242.2	159.4	162.0	276.6	216.1	316.6
1070	137.3	243.1	160.3	162.8	277.4	216.5	317.4
1080	138.2	244.1	161.2	163.6	278.1	216.8	318.1
1090	139.0	245.0	162.0	164.4	278.9	217.1	318.9
1100	139.9	245.9	162.9	165.1	279.6	217.5	319.6
1110	140.7	246.8	163.7	165.9	280.4	217.8	320.4
1120	141.5	247.7	164.6	166.7	281.1	218.1	321.1
1130	142.3	248.6	165.4	167.4	281.8	218.4	321.8
1140	143.1	249.5	166.2	168.1	282.5	218.8	322.5
1150	143.9	250.3	167.0	168.9	283.3	219.1	323.3
1160	144.7	251.2	167.8	169.6	284.0	219.4	324.0
1170	145.5	252.0	168.6	170.3	284.7	219.7	324.7
1180	146.2	252.9	169.4	171.0	285.3	220.0	325.3
1190	147.0	253.7	170.2	171.7	286.0	220.4	326.0
1200	147.7	254.5	170.9	172.4	286.7	220.7	326.7
1210	148.5	255.3	171.7	173.1	287.4	221.0	327.4
1220	149.2	256.1	172.4	173.8	288.0	221.3	328.0
1230	149.9	256.9	173.2	174.5	288.7	221.6	328.7
1240	150.6	257.6	173.9	175.1	289.3	221.9	329.3
1250	151.3	258.4	174.6	175.8	290.0	222.2	330.0
1260	152.0	259.1	175.4	176.5	290.6	222.5	330.6
1270	152.7	259.9	176.1	177.1	291.3	222.8	331.3
1280	153.4	260.6	176.8	177.8	291.9	223.1	331.9
1290	154.1	261.4	177.5	178.4	292.5	223.4	332.5
1300	154.8	262.1	178.1	179.0	293.1	223.7	333.1
1310	155.4	262.8	178.8	179.6	293.7	224.0	333.7

TABLE B-1. Hatch Unit 1 P-T Curve Values for 40 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES B-1 THROUGH B-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	40 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	40 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	40 EFPY RPV CURVE C (°F)
1320	156.1	263.5	179.5	180.3	294.3	224.3	334.3
1330	156.8	264.2	180.2	180.9	294.9	224.6	334.9
1340	157.4	264.9	180.8	181.5	295.5	224.9	335.5
1350	158.1	265.6	181.5	182.1	296.1	225.2	336.1
1360	158.7	266.3	182.1	182.7	296.7	225.5	336.7
1370	159.3	267.0	182.8	183.3	297.3	225.8	337.3
1380	159.9	267.6	183.4	183.9	297.9	226.1	337.9
1390	160.6	268.3	184.0	184.5	298.4	226.4	338.4
1400	161.2	268.9	184.7	185.0	299.0	226.7	339.0

APPENDIX C
HATCH UNIT 1 P-T CURVE
VALID TO 44 EFPY

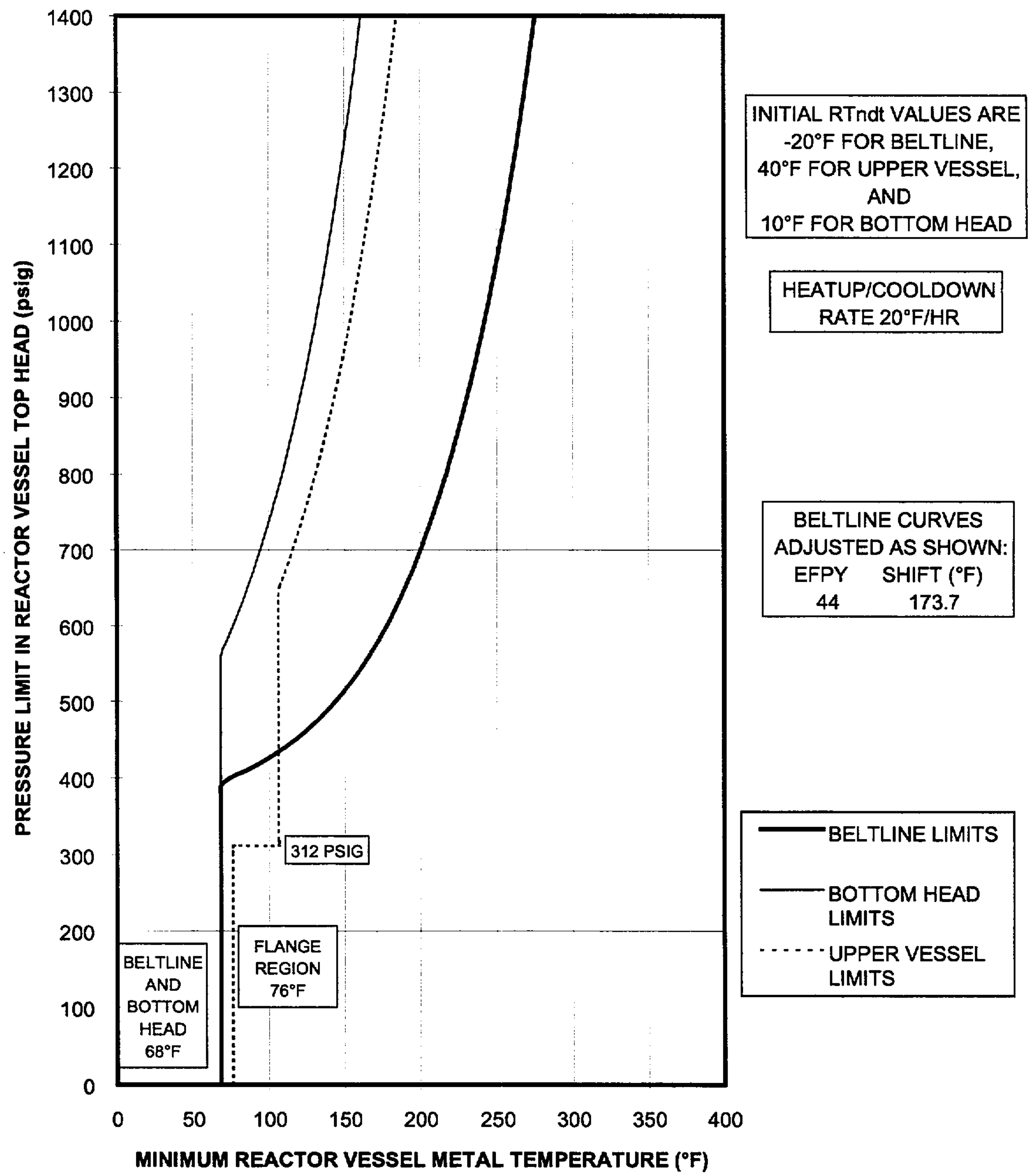


Figure C-1: P-T Curve for Unit 1 (Curve A)

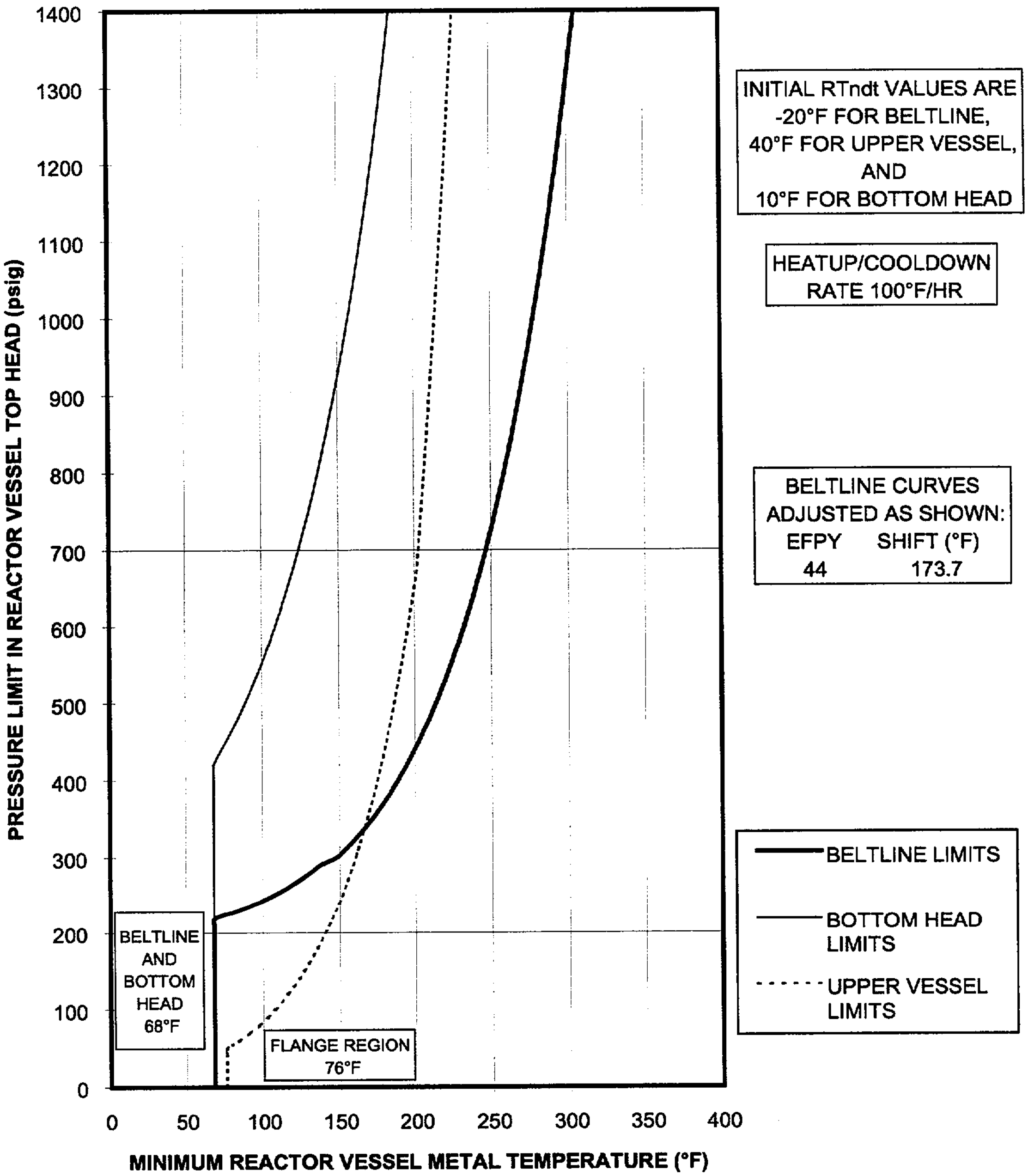


Figure C-2: P-T Curve for Unit 1 (Curve B)

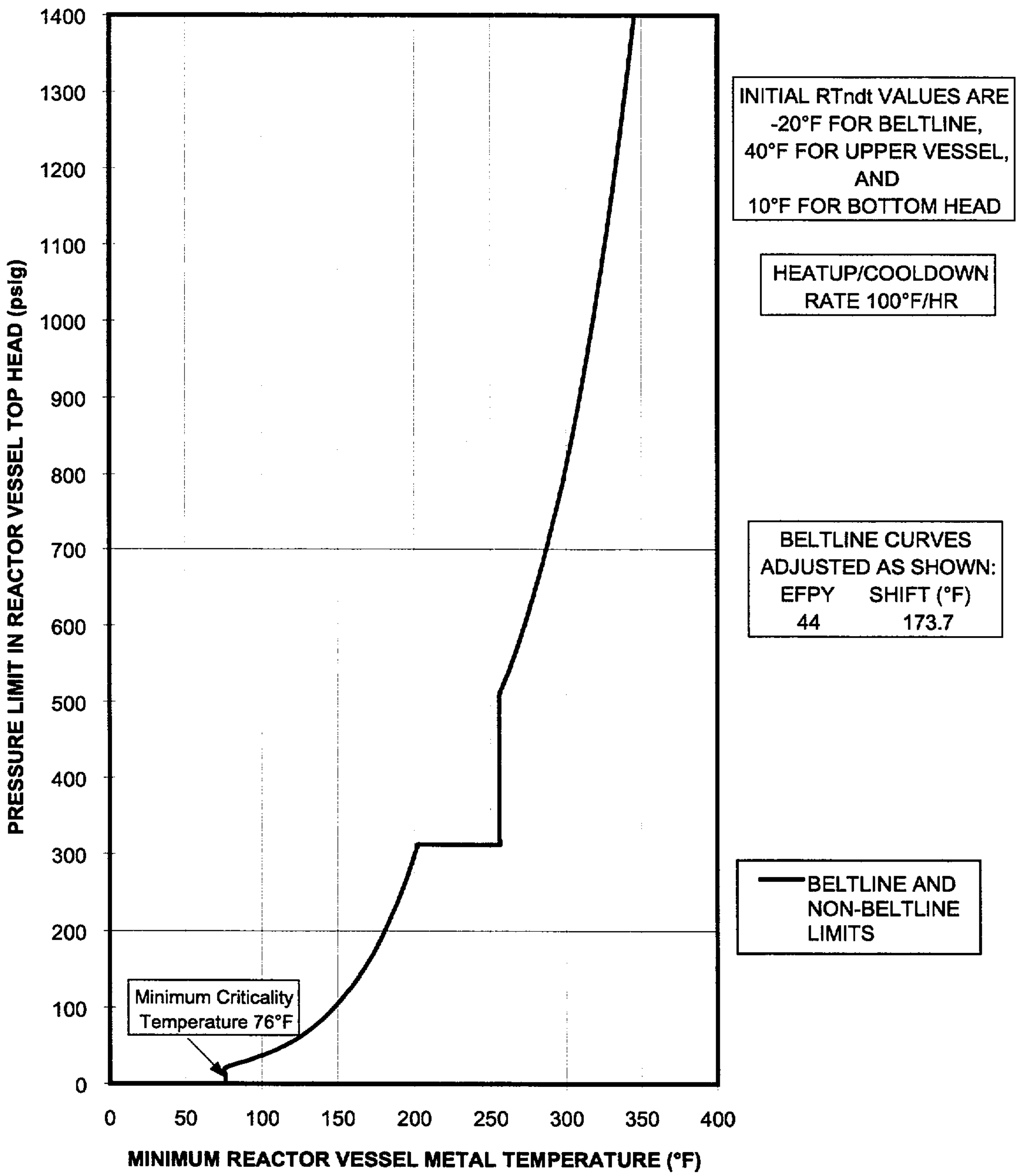


Figure C-3: P-T Curve for Unit 1 (Curve C)

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	68.7	145.2	185.2
230	68.0	68.0	76.0	68.0	83.9	147.4	187.4
240	68.0	68.0	76.0	68.0	96.3	149.4	189.4
250	68.0	68.0	76.0	68.0	106.8	151.4	191.4

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	115.9	153.3	193.3
270	68.0	68.0	76.0	68.0	124.0	155.1	195.1
280	68.0	68.0	76.0	68.0	131.2	157.0	197.0
290	68.0	68.0	76.0	68.0	137.7	158.7	198.7
300	68.0	68.0	76.0	68.0	148.0	160.3	200.3
310	68.0	68.0	76.0	68.0	153.3	162.0	202.0
312.5	68.0	68.0	76.0	68.0	154.6	162.3	202.3
312.5	68.0	68.0	106.0	68.0	154.6	162.3	255.7
320	68.0	68.0	106.0	68.0	158.2	163.5	255.7
330	68.0	68.0	106.0	68.0	162.8	165.1	255.7
340	68.0	68.0	106.0	68.0	167.1	166.6	255.7
350	68.0	68.0	106.0	68.0	171.2	168.0	255.7
360	68.0	68.0	106.0	68.0	175.0	169.4	255.7
370	68.0	68.0	106.0	68.0	178.6	170.8	255.7
380	68.0	68.0	106.0	68.0	182.0	172.1	255.7
390	68.0	68.0	106.0	68.0	185.3	173.4	255.7
400	68.0	73.8	106.0	68.0	188.5	174.7	255.7
410	68.0	84.9	106.0	68.0	191.4	176.0	255.7
420	68.0	94.5	106.0	68.0	194.3	177.2	255.7
430	68.0	103.0	106.0	70.3	197.1	178.4	255.7
440	68.0	110.5	106.0	73.2	199.7	179.6	255.7
450	68.0	117.2	106.0	76.1	202.3	180.7	255.7
460	68.0	123.4	106.0	78.8	204.7	181.8	255.7
470	68.0	129.0	106.0	81.5	207.1	182.9	255.7
480	68.0	134.3	106.0	84.0	209.4	184.0	255.7
490	68.0	139.1	106.0	86.5	211.6	185.1	255.7
500	68.0	143.6	106.0	88.8	213.8	186.1	255.7

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
510	68.0	147.9	106.0	91.1	215.8	187.1	255.8
520	68.0	151.9	106.0	93.3	217.9	188.1	257.9
530	68.0	155.7	106.0	95.5	219.8	189.1	259.8
540	68.0	159.3	106.0	97.6	221.8	190.1	261.8
550	68.0	162.7	106.0	99.6	223.6	191.1	263.6
560	68.0	166.0	106.0	101.5	225.4	192.0	265.4
570	69.5	169.1	106.0	103.5	227.2	192.9	267.2
580	71.8	172.0	106.0	105.3	228.9	193.8	268.9
590	74.0	174.9	106.0	107.1	230.6	194.7	270.6
600	76.1	177.6	106.0	108.9	232.2	195.6	272.2
610	78.2	180.3	106.0	110.6	233.8	196.5	273.8
620	80.2	182.8	106.0	112.3	235.4	197.3	275.4
630	82.1	185.2	106.0	113.9	236.9	198.2	276.9
640	84.0	187.6	106.0	115.5	238.4	199.0	278.4
650	85.9	189.9	106.7	117.1	239.9	199.8	279.9
660	87.7	192.1	108.6	118.6	241.3	200.6	281.3
670	89.4	194.2	110.4	120.1	242.7	201.4	282.7
680	91.1	196.3	112.2	121.6	244.1	201.9	284.1
690	92.8	198.3	114.0	123.0	245.5	202.3	285.5
700	94.4	200.3	115.7	124.4	246.8	202.8	286.8
710	96.0	202.2	117.4	125.8	248.1	203.2	288.1
720	97.6	204.1	119.0	127.1	249.4	203.6	289.4
730	99.1	205.9	120.6	128.4	250.6	204.0	290.6
740	100.6	207.6	122.2	129.7	251.9	204.4	291.9
750	102.0	209.3	123.7	131.0	253.1	204.8	293.1
760	103.5	211.0	125.2	132.3	254.2	205.2	294.2
770	104.8	212.6	126.7	133.5	255.4	205.6	295.4

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
780	106.2	214.2	128.1	134.7	256.6	206.0	296.6
790	107.6	215.8	129.5	135.9	257.7	206.4	297.7
800	108.9	217.3	130.9	137.0	258.8	206.7	298.8
810	110.2	218.8	132.2	138.2	259.9	207.1	299.9
820	111.4	220.3	133.5	139.3	261.0	207.5	301.0
830	112.7	221.7	134.8	140.4	262.0	207.9	302.0
840	113.9	223.1	136.1	141.5	263.1	208.3	303.1
850	115.1	224.5	137.3	142.6	264.1	208.7	304.1
860	116.3	225.8	138.6	143.6	265.1	209.0	305.1
870	117.5	227.2	139.8	144.7	266.1	209.4	306.1
880	118.6	228.4	140.9	145.7	267.1	209.8	307.1
890	119.7	229.7	142.1	146.7	268.1	210.1	308.1
900	120.8	231.0	143.3	147.7	269.0	210.5	309.0
910	121.9	232.2	144.4	148.7	270.0	210.9	310.0
920	123.0	233.4	145.5	149.7	270.9	211.2	310.9
930	124.0	234.6	146.6	150.6	271.8	211.6	311.8
940	125.1	235.8	147.7	151.6	272.7	212.0	312.7
950	126.1	236.9	148.7	152.5	273.6	212.3	313.6
960	127.1	238.0	149.8	153.4	274.5	212.7	314.5
970	128.1	239.1	150.8	154.3	275.4	213.0	315.4
980	129.1	240.2	151.8	155.2	276.2	213.4	316.2
990	130.0	241.3	152.8	156.1	277.1	213.7	317.1
1000	131.0	242.4	153.8	157.0	277.9	214.1	317.9
1010	131.9	243.4	154.7	157.8	278.8	214.4	318.8
1020	132.9	244.4	155.7	158.7	279.6	214.8	319.6
1030	133.8	245.4	156.6	159.5	280.4	215.1	320.4
1040	134.7	246.4	157.6	160.4	281.2	215.4	321.2

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
1050	135.6	247.4	158.5	161.2	282.0	215.8	322.0
1060	136.5	248.4	159.4	162.0	282.8	216.1	322.8
1070	137.3	249.3	160.3	162.8	283.6	216.5	323.6
1080	138.2	250.3	161.2	163.6	284.3	216.8	324.3
1090	139.0	251.2	162.0	164.4	285.1	217.1	325.1
1100	139.9	252.1	162.9	165.1	285.8	217.5	325.8
1110	140.7	253.0	163.7	165.9	286.6	217.8	326.6
1120	141.5	253.9	164.6	166.7	287.3	218.1	327.3
1130	142.3	254.8	165.4	167.4	288.0	218.4	328.0
1140	143.1	255.7	166.2	168.1	288.7	218.8	328.7
1150	143.9	256.5	167.0	168.9	289.5	219.1	329.5
1160	144.7	257.4	167.8	169.6	290.2	219.4	330.2
1170	145.5	258.2	168.6	170.3	290.9	219.7	330.9
1180	146.2	259.1	169.4	171.0	291.5	220.0	331.5
1190	147.0	259.9	170.2	171.7	292.2	220.4	332.2
1200	147.7	260.7	170.9	172.4	292.9	220.7	332.9
1210	148.5	261.5	171.7	173.1	293.6	221.0	333.6
1220	149.2	262.3	172.4	173.8	294.2	221.3	334.2
1230	149.9	263.1	173.2	174.5	294.9	221.6	334.9
1240	150.6	263.8	173.9	175.1	295.5	221.9	335.5
1250	151.3	264.6	174.6	175.8	296.2	222.2	336.2
1260	152.0	265.3	175.4	176.5	296.8	222.5	336.8
1270	152.7	266.1	176.1	177.1	297.5	222.8	337.5
1280	153.4	266.8	176.8	177.8	298.1	223.1	338.1
1290	154.1	267.6	177.5	178.4	298.7	223.4	338.7
1300	154.8	268.3	178.1	179.0	299.3	223.7	339.3
1310	155.4	269.0	178.8	179.6	299.9	224.0	339.9

TABLE C-1. Hatch Unit 1 P-T Curve Values for 44 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES C-1 THROUGH C-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	44 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	44 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	44 EFPY RPV CURVE C (°F)
1320	156.1	269.7	179.5	180.3	300.5	224.3	340.5
1330	156.8	270.4	180.2	180.9	301.1	224.6	341.1
1340	157.4	271.1	180.8	181.5	301.7	224.9	341.7
1350	158.1	271.8	181.5	182.1	302.3	225.2	342.3
1360	158.7	272.5	182.1	182.7	302.9	225.5	342.9
1370	159.3	273.2	182.8	183.3	303.5	225.8	343.5
1380	159.9	273.8	183.4	183.9	304.1	226.1	344.1
1390	160.6	274.5	184.0	184.5	304.6	226.4	344.6
1400	161.2	275.1	184.7	185.0	305.2	226.7	345.2

APPENDIX D

HATCH UNIT 1 P-T CURVES

VALID TO 48 EFPY

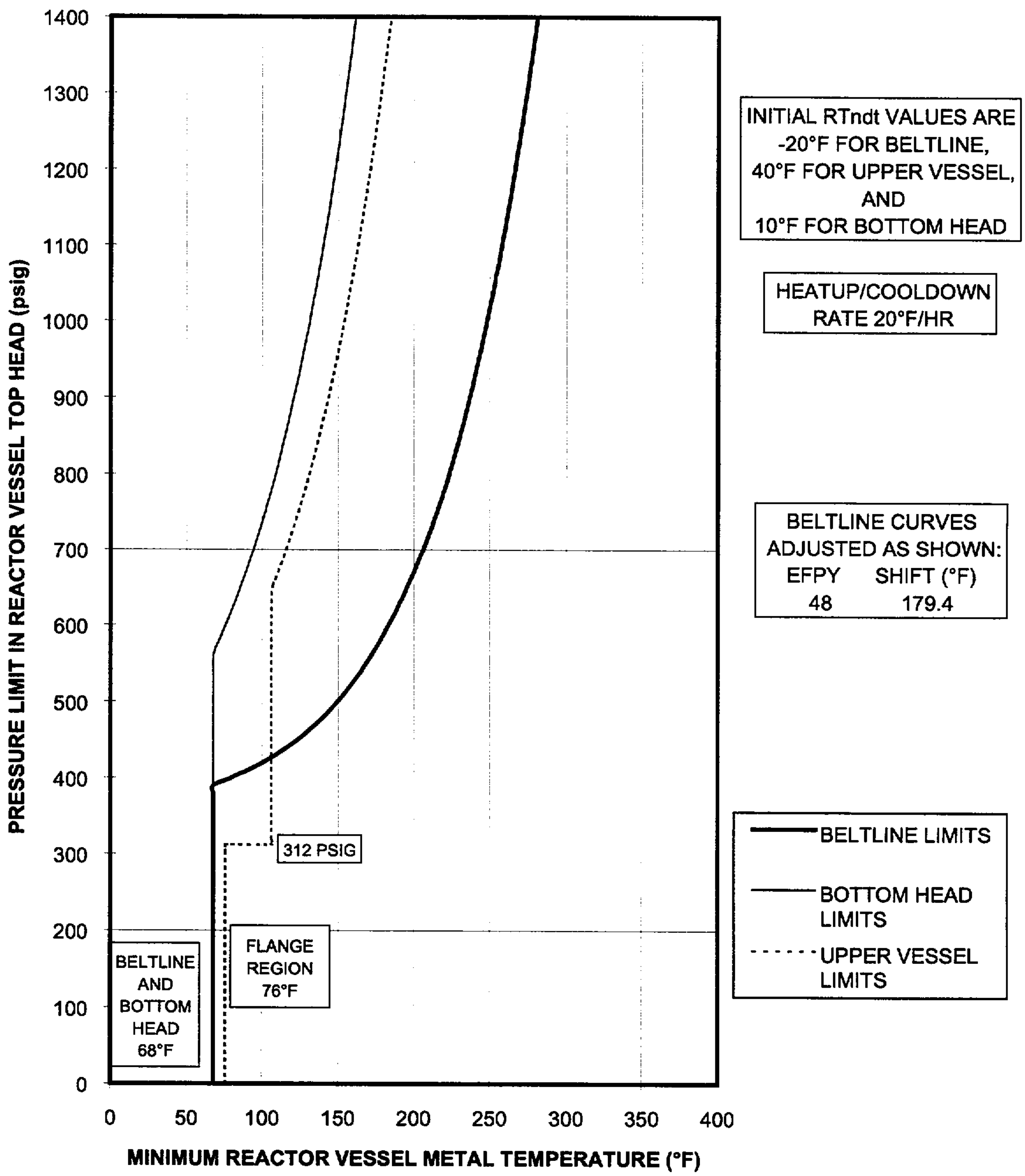


Figure D-1: P-T Curve for Unit 1 (Curve A)

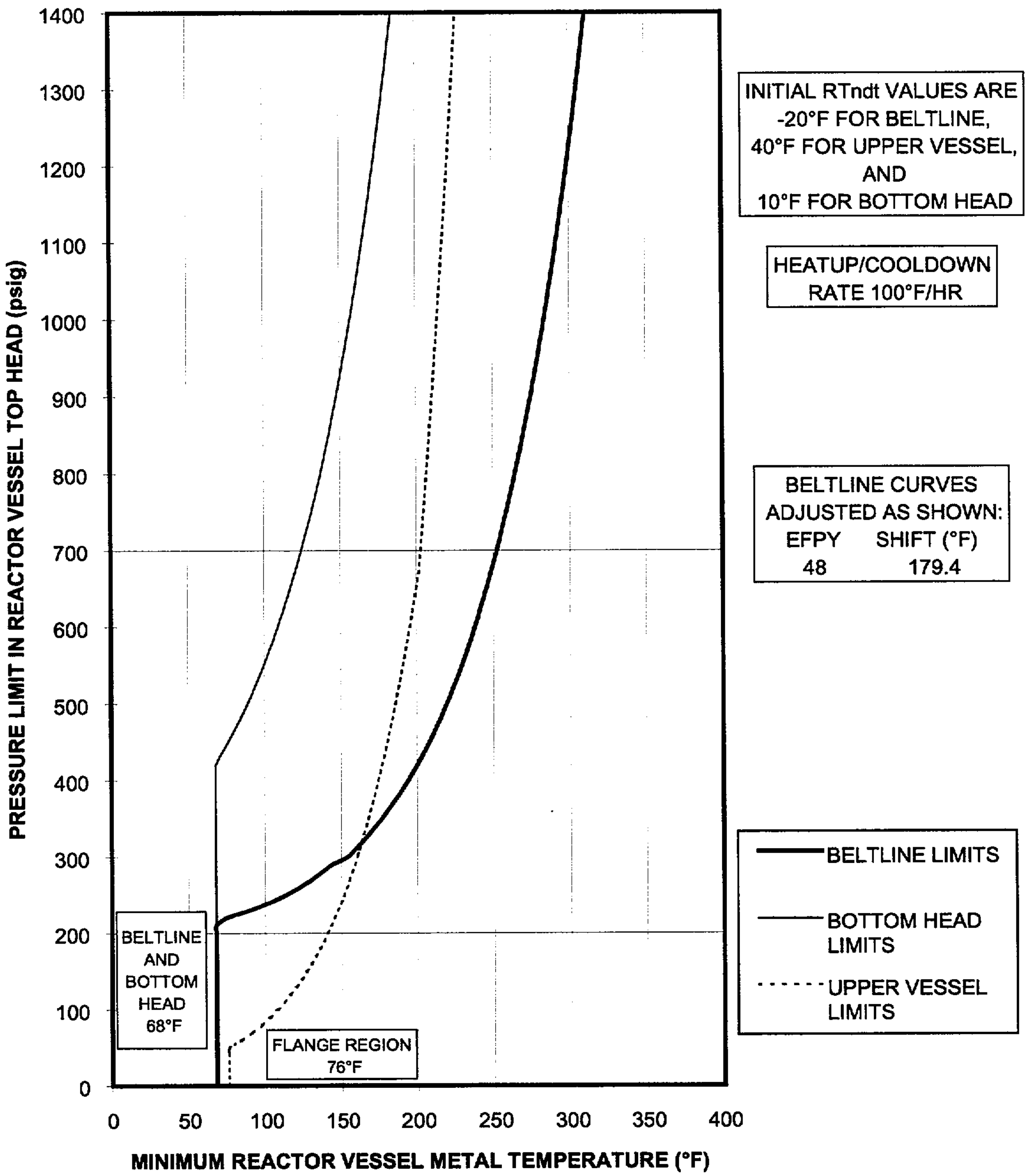


Figure D-2: P-T Curve for Unit 1 (Curve B)

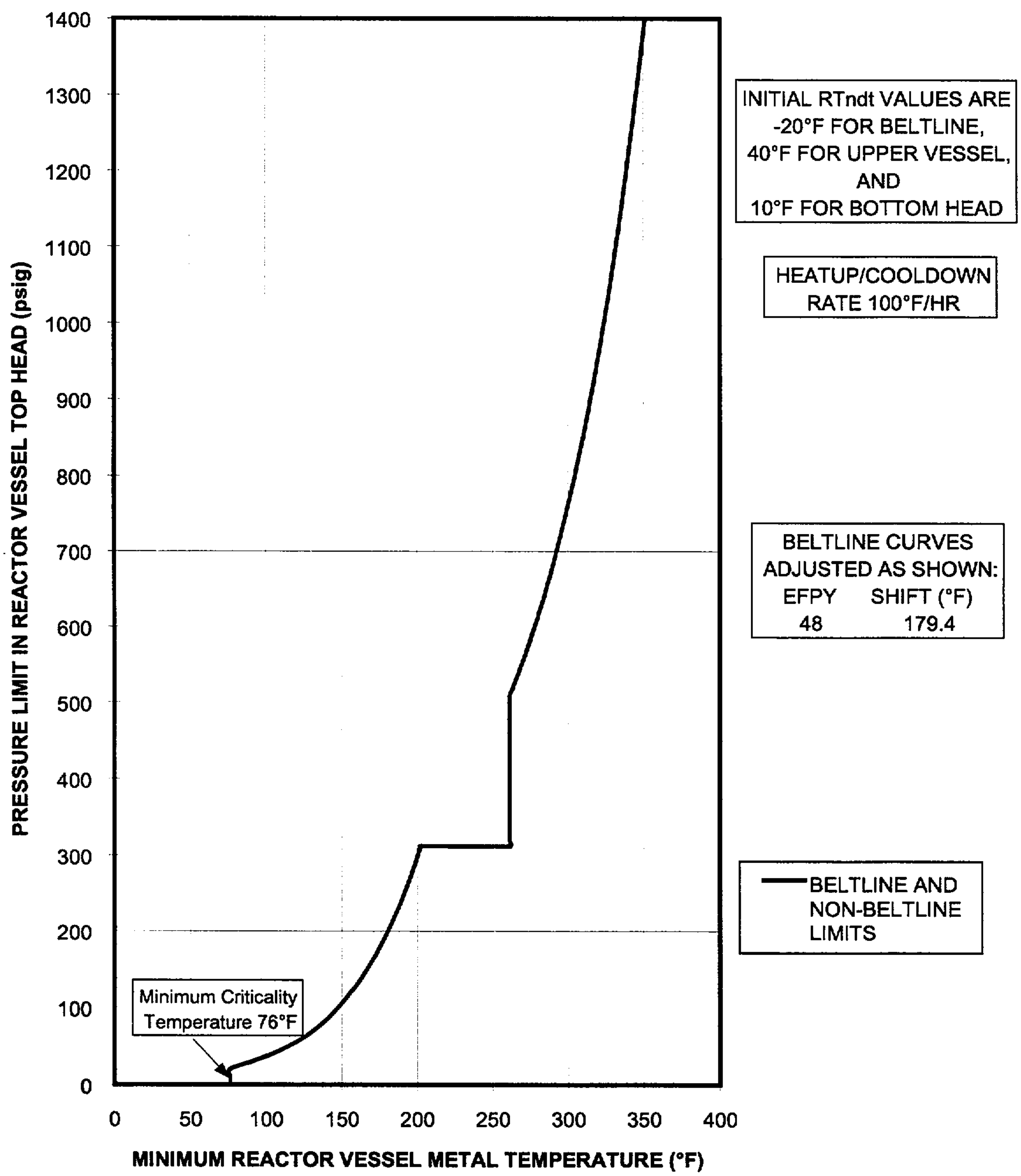


Figure D-3: P-T Curve for Unit 1 (Curve C)

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE	BOTTOM HEAD CURVE A	48 EFPY BELTLINE CURVE A	UPPER VESSEL CURVE A	BOTTOM HEAD CURVE B	48 EFPY BELTLINE CURVE B	UPPER VESSEL CURVE B	48 EFPY RPV CURVE C
(PSIG)	(°F)	(°F)	(°F)	(°F)	(°F)	(°F)	(°F)
0	68.0	68.0	76.0	68.0	68.0	76.0	76.0
10	68.0	68.0	76.0	68.0	68.0	76.0	76.0
20	68.0	68.0	76.0	68.0	68.0	76.0	76.0
30	68.0	68.0	76.0	68.0	68.0	76.0	90.6
40	68.0	68.0	76.0	68.0	68.0	76.0	104.5
50	68.0	68.0	76.0	68.0	68.0	76.0	115.2
60	68.0	68.0	76.0	68.0	68.0	83.9	123.9
70	68.0	68.0	76.0	68.0	68.0	91.1	131.1
80	68.0	68.0	76.0	68.0	68.0	97.4	137.4
90	68.0	68.0	76.0	68.0	68.0	102.7	142.7
100	68.0	68.0	76.0	68.0	68.0	107.5	147.5
110	68.0	68.0	76.0	68.0	68.0	111.9	151.9
120	68.0	68.0	76.0	68.0	68.0	116.1	156.1
130	68.0	68.0	76.0	68.0	68.0	120.1	160.1
140	68.0	68.0	76.0	68.0	68.0	123.6	163.6
150	68.0	68.0	76.0	68.0	68.0	126.8	166.8
160	68.0	68.0	76.0	68.0	68.0	129.8	169.8
170	68.0	68.0	76.0	68.0	68.0	132.8	172.8
180	68.0	68.0	76.0	68.0	68.0	135.6	175.6
190	68.0	68.0	76.0	68.0	68.0	138.2	178.2
200	68.0	68.0	76.0	68.0	68.0	140.6	180.6
210	68.0	68.0	76.0	68.0	68.0	142.9	182.9
220	68.0	68.0	76.0	68.0	74.4	145.2	185.2
230	68.0	68.0	76.0	68.0	89.6	147.4	187.4
240	68.0	68.0	76.0	68.0	102.0	149.4	189.4
250	68.0	68.0	76.0	68.0	112.5	151.4	191.4

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
260	68.0	68.0	76.0	68.0	121.6	153.3	193.3
270	68.0	68.0	76.0	68.0	129.7	155.1	195.1
280	68.0	68.0	76.0	68.0	136.9	157.0	197.0
290	68.0	68.0	76.0	68.0	143.4	158.7	198.7
300	68.0	68.0	76.0	68.0	153.7	160.3	200.3
310	68.0	68.0	76.0	68.0	159.0	162.0	202.0
312.5	68.0	68.0	76.0	68.0	160.3	162.3	202.3
312.5	68.0	68.0	106.0	68.0	160.3	162.3	261.4
320	68.0	68.0	106.0	68.0	163.9	163.5	261.4
330	68.0	68.0	106.0	68.0	168.5	165.1	261.4
340	68.0	68.0	106.0	68.0	172.8	166.6	261.4
350	68.0	68.0	106.0	68.0	176.9	168.0	261.4
360	68.0	68.0	106.0	68.0	180.7	169.4	261.4
370	68.0	68.0	106.0	68.0	184.3	170.8	261.4
380	68.0	68.0	106.0	68.0	187.7	172.1	261.4
390	68.0	68.0	106.0	68.0	191.0	173.4	261.4
400	68.0	79.5	106.0	68.0	194.2	174.7	261.4
410	68.0	90.6	106.0	68.0	197.1	176.0	261.4
420	68.0	100.2	106.0	68.0	200.0	177.2	261.4
430	68.0	108.7	106.0	70.3	202.8	178.4	261.4
440	68.0	116.2	106.0	73.2	205.4	179.6	261.4
450	68.0	122.9	106.0	76.1	208.0	180.7	261.4
460	68.0	129.1	106.0	78.8	210.4	181.8	261.4
470	68.0	134.7	106.0	81.5	212.8	182.9	261.4
480	68.0	140.0	106.0	84.0	215.1	184.0	261.4
490	68.0	144.8	106.0	86.5	217.3	185.1	261.4
500	68.0	149.3	106.0	88.8	219.5	186.1	261.4

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
510	68.0	153.6	106.0	91.1	221.5	187.1	261.5
520	68.0	157.6	106.0	93.3	223.6	188.1	263.6
530	68.0	161.4	106.0	95.5	225.5	189.1	265.5
540	68.0	165.0	106.0	97.6	227.5	190.1	267.5
550	68.0	168.4	106.0	99.6	229.3	191.1	269.3
560	68.0	171.7	106.0	101.5	231.1	192.0	271.1
570	69.5	174.8	106.0	103.5	232.9	192.9	272.9
580	71.8	177.7	106.0	105.3	234.6	193.8	274.6
590	74.0	180.6	106.0	107.1	236.3	194.7	276.3
600	76.1	183.3	106.0	108.9	237.9	195.6	277.9
610	78.2	186.0	106.0	110.6	239.5	196.5	279.5
620	80.2	188.5	106.0	112.3	241.1	197.3	281.1
630	82.1	190.9	106.0	113.9	242.6	198.2	282.6
640	84.0	193.3	106.0	115.5	244.1	199.0	284.1
650	85.9	195.6	106.7	117.1	245.6	199.8	285.6
660	87.7	197.8	108.6	118.6	247.0	200.6	287.0
670	89.4	199.9	110.4	120.1	248.4	201.4	288.4
680	91.1	202.0	112.2	121.6	249.8	201.9	289.8
690	92.8	204.0	114.0	123.0	251.2	202.3	291.2
700	94.4	206.0	115.7	124.4	252.5	202.8	292.5
710	96.0	207.9	117.4	125.8	253.8	203.2	293.8
720	97.6	209.8	119.0	127.1	255.1	203.6	295.1
730	99.1	211.6	120.6	128.4	256.3	204.0	296.3
740	100.6	213.3	122.2	129.7	257.6	204.4	297.6
750	102.0	215.0	123.7	131.0	258.8	204.8	298.8
760	103.5	216.7	125.2	132.3	259.9	205.2	299.9
770	104.8	218.3	126.7	133.5	261.1	205.6	301.1

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
780	106.2	219.9	128.1	134.7	262.3	206.0	302.3
790	107.6	221.5	129.5	135.9	263.4	206.4	303.4
800	108.9	223.0	130.9	137.0	264.5	206.7	304.5
810	110.2	224.5	132.2	138.2	265.6	207.1	305.6
820	111.4	226.0	133.5	139.3	266.7	207.5	306.7
830	112.7	227.4	134.8	140.4	267.7	207.9	307.7
840	113.9	228.8	136.1	141.5	268.8	208.3	308.8
850	115.1	230.2	137.3	142.6	269.8	208.7	309.8
860	116.3	231.5	138.6	143.6	270.8	209.0	310.8
870	117.5	232.9	139.8	144.7	271.8	209.4	311.8
880	118.6	234.1	140.9	145.7	272.8	209.8	312.8
890	119.7	235.4	142.1	146.7	273.8	210.1	313.8
900	120.8	236.7	143.3	147.7	274.7	210.5	314.7
910	121.9	237.9	144.4	148.7	275.7	210.9	315.7
920	123.0	239.1	145.5	149.7	276.6	211.2	316.6
930	124.0	240.3	146.6	150.6	277.5	211.6	317.5
940	125.1	241.5	147.7	151.6	278.4	212.0	318.4
950	126.1	242.6	148.7	152.5	279.3	212.3	319.3
960	127.1	243.7	149.8	153.4	280.2	212.7	320.2
970	128.1	244.8	150.8	154.3	281.1	213.0	321.1
980	129.1	245.9	151.8	155.2	281.9	213.4	321.9
990	130.0	247.0	152.8	156.1	282.8	213.7	322.8
1000	131.0	248.1	153.8	157.0	283.6	214.1	323.6
1010	131.9	249.1	154.7	157.8	284.5	214.4	324.5
1020	132.9	250.1	155.7	158.7	285.3	214.8	325.3
1030	133.8	251.1	156.6	159.5	286.1	215.1	326.1
1040	134.7	252.1	157.6	160.4	286.9	215.4	326.9

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	48 EFPY BELTLINE CURVE A (°F)	UPPER VESSEL CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	48 EFPY BELTLINE CURVE B (°F)	UPPER VESSEL CURVE B (°F)	48 EFPY RPV CURVE C (°F)
1050	135.6	253.1	158.5	161.2	287.7	215.8	327.7
1060	136.5	254.1	159.4	162.0	288.5	216.1	328.5
1070	137.3	255.0	160.3	162.8	289.3	216.5	329.3
1080	138.2	256.0	161.2	163.6	290.0	216.8	330.0
1090	139.0	256.9	162.0	164.4	290.8	217.1	330.8
1100	139.9	257.8	162.9	165.1	291.5	217.5	331.5
1110	140.7	258.7	163.7	165.9	292.3	217.8	332.3
1120	141.5	259.6	164.6	166.7	293.0	218.1	333.0
1130	142.3	260.5	165.4	167.4	293.7	218.4	333.7
1140	143.1	261.4	166.2	168.1	294.4	218.8	334.4
1150	143.9	262.2	167.0	168.9	295.2	219.1	335.2
1160	144.7	263.1	167.8	169.6	295.9	219.4	335.9
1170	145.5	263.9	168.6	170.3	296.6	219.7	336.6
1180	146.2	264.8	169.4	171.0	297.2	220.0	337.2
1190	147.0	265.6	170.2	171.7	297.9	220.4	337.9
1200	147.7	266.4	170.9	172.4	298.6	220.7	338.6
1210	148.5	267.2	171.7	173.1	299.3	221.0	339.3
1220	149.2	268.0	172.4	173.8	299.9	221.3	339.9
1230	149.9	268.8	173.2	174.5	300.6	221.6	340.6
1240	150.6	269.5	173.9	175.1	301.2	221.9	341.2
1250	151.3	270.3	174.6	175.8	301.9	222.2	341.9
1260	152.0	271.0	175.4	176.5	302.5	222.5	342.5
1270	152.7	271.8	176.1	177.1	303.2	222.8	343.2
1280	153.4	272.5	176.8	177.8	303.8	223.1	343.8
1290	154.1	273.3	177.5	178.4	304.4	223.4	344.4
1300	154.8	274.0	178.1	179.0	305.0	223.7	345.0
1310	155.4	274.7	178.8	179.6	305.6	224.0	345.6

TABLE D-1. Hatch Unit 1 P-T Curve Values for 48 EFPY

Required Temperatures at 100 °F/hr for Curves B & C and 20 °F/hr for Curve A

(FOR FIGURES D-1 THROUGH D-3)

PRESSURE	BOTTOM HEAD CURVE A	48 EFPY BELTLINE CURVE A	UPPER VESSEL CURVE A	BOTTOM HEAD CURVE B	48 EFPY BELTLINE CURVE B	UPPER VESSEL CURVE B	48 EFPY RPV CURVE C
(PSIG)	(°F)	(°F)	(°F)	(°F)	(°F)	(°F)	(°F)
1320	156.1	275.4	179.5	180.3	306.2	224.3	346.2
1330	156.8	276.1	180.2	180.9	306.8	224.6	346.8
1340	157.4	276.8	180.8	181.5	307.4	224.9	347.4
1350	158.1	277.5	181.5	182.1	308.0	225.2	348.0
1360	158.7	278.2	182.1	182.7	308.6	225.5	348.6
1370	159.3	278.9	182.8	183.3	309.2	225.8	349.2
1380	159.9	279.5	183.4	183.9	309.8	226.1	349.8
1390	160.6	280.2	184.0	184.5	310.3	226.4	350.3
1400	161.2	280.8	184.7	185.0	310.9	226.7	350.9