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SOUTHERN COMPANY
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June 5, 2001

Docket Nos. 50-321
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U. S. Nuclear Regulatory Commission
ATTN.: Document Control Desk
Washington, DC 20555

Edwin I. Hatch Nuclear Plant
Transmittal of Responses to
License Renewal Draft SER Open Items

Ladies and Gentlemen:

By letter dated February 7, 2001, the NRC transmitted the "Safety Evaluation Report With Open Items Related to the License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2." A total of eighteen open items are included in this report. SNC has reviewed these items and has developed additional information in response to the open items. The additional information was provided to NRC staff via a number of electronic communications from February 23 through June 4, 2001. This letter formally transmits the collected responses to the eighteen open items to NRC. Enclosure 1 contains an item by item chronology of responses to selected draft open items. Enclosure 1 also provides the responses to the open items. Enclosure 2 provides the FSAR supplement in response to open item 3.0-1. Enclosure 3 provides revised Appendix B program descriptions for the fire protection program and the structural monitoring program.

If you have any questions concerning this information, please contact this office.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

HLS/JAM/RDB

Enclosures: 1. Chronology and Responses to Draft SER Open Items
2. FSAR Supplement
3. Revised Appendix B Sections B.2.1 and B.2.5

A083

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
Mr. C. R. Pierce, License Renewal Services Manager

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ENCLOSURE 1

CONSOLIDATED RESPONSES

TO

DRAFT SER OPEN ITEMS

REGARDING THE PLANT HATCH

LICENSE RENEWAL APPLICATION

June 4, 2001

Table of Contents

Table of Figures

Chronology

By electronic communications (e-mails) on February 23, March 6, April 17, April 24, May 2, May 6, May 21, and June 4 2001, SNC provided partial responses to the draft NRC SER open items. The following chronology of open item responses is arranged by open item number.

Open Item 2.1.3.1-1 Seismic II/I

An open item resolution meeting was held with NRC staff on April 29, 2001. Based on the results of that meeting, SNC provided an initial response to this open item on April 17, 2001. Further technical discussion was conducted in a May 24, 2001 meeting. This item will be further discussed in an appeal meeting on June 6, 2001.

Open Item 2.3.3.2-1 (a) Aging Management Review of Hydrogen Recombiner

SNC provided an initial response to this open item on April 17, 2001.

Open Item 2.3.3.2-1 (b) Aging Management Review of EDG

SNC provided an initial response to this open item on April 17, 2001. On May 21, 2001 SNC provided a revised response to address NRC staff comments. This submittal documents that May 21 response.

Open Item 2.3.3.2-2 (a), (c), (d) Fans and Dampers

An open item resolution meeting was held with NRC staff on April 29, 2001. Based on the results of that meeting, SNC provided an initial response to this open item on April 17, 2001. On May 2, 2001 the response was revised and expanded to address staff questions. On May 21, 2001 the response was again revised to address additional staff comments.

Open Item 2.3.3.2-2 (b) LPCI Inverter Room

SNC provided an initial response to this open item on April 17, 2001.

Open Item 2.3.4.2-1 Radwaste Building Fixed Fire Suppression

SNC provided an initial response to this open item on April 17, 2001.

Open Item 3.0-1 FSAR Supplement

SNC provided an initial response to this open item on May 6, 2001. On May 21, 2001 as part of expanded SNC responses to open items 2.3.3.2-1 (b) and 2.3.3.2-2 (a), (c), (d), three programs described in the FSAR supplement were revised to incorporate staff comments. The FSAR supplement pages that are provided as part of this response incorporate the revisions in the May 21, 2001 response.

Open Item 3.1.1-1 Use of EPRI TR-103515, Revision 2

SNC provided an initial response to this open item on February 23, 2001.

Open Item 3.1.3-1 Diesel Fuel Oil Tank Inspection

SNC provided an initial response to this open item on February 23, 2001. SNC expanded the response to address staff comments in a March 6, 2001 response.

Open Item 3.1.11-1 High Strength Bolting

SNC provided an initial response to this open item on April 17, 2001.

Open Item 3.1.13-1 (a), (b), (c) Miscellaneous PSW Clarifications

SNC provided an initial response to open item 3.1.13-1 (a) on February 23, 2001. On April 17, 2001 that response was revised to address staff comments. In addition, SNC provided an initial response to parts (b) and (c) of the open item on April 17, 2001.

Open Item 3.1.17-1 RPV ISP (BWRVIP-78)

This item was originally issued as RAI 3.1.17-1. This submittal documents the results of telecon discussions regarding the RAI response.

Open Item 3.1.18-1 (a) Fire Sprinkler flow

This item was closed by NRC on its own initiative.

Open Item 3.1.18-1 (b) Closed-head Sprinkler Testing

SNC provided an initial response to this open item on May 6, 2001.

Open Item 3.1.28-1 (a), (b), (c), (d) RHR Service Water Heat Exchanger Augmented Inspection Program

SNC provided an initial response to this open item on April 17, 2001.

Open Item 3.2.3.1.1-1 RPV Internals CASS and BWRVIP-41

SNC provided an initial response to this open item on February 23, 2001.

Open Item 3.2.3.2.3-1 Small-bore Pipe

An open item resolution meeting was held with NRC staff on March 29, 2001. Based on the results of that meeting, SNC produced a draft response for use during subsequent telecons. This item is the subject of an appeal meeting scheduled for June 6, 2001. In response to the open item, the draft response previously generated is provided pending completion of the appeal process.

Open Item 3.6.3.1-1 Secondary Containment Verification Testing

An open item resolution meeting was held with NRC staff on March 29, 2001. Based on the results of that meeting, SNC provided an initial response to this open item on May 6, 2001.

Open Item 3.6.3.2-1 (a) (b) Torus Programs; Latches and Hinges

These items were closed by NRC on its own initiative.

Open Item 4.1.3-1 (a) Vessel Internals Fatigue and BWRVIP-74

SNC provided an initial response to this open item on May 6, 2001.

Open Item 4.1.3-1 (b) Pipe Break Criteria as a TLAA

This item is the subject of an appeal meeting on June 6, 2001.

Open Item 4.2.3-1 Environmental Effects of Reactor Coolant Water

SNC provided an initial response to this open item on April 17, 2001. This item is the subject of an appeal meeting scheduled for June 6, 2001.

Open Item 2.1.3.1-1

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4 (a)(1)(i), (ii), or (iii). In Section 2.1.2.5 of the LRA, the applicant stated that the few cases where non-safety-related components could impact safety-related functions were included in the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2). In the staff's requests for additional information (RAIs) 3.4-11 and 3.6-51, dated July 28, 2000, the staff requested that the applicant clarify whether the scope of the auxiliary systems discussed in Section 3.2.4 of the LRA includes any spatially-related components and piping segments within the category of "Seismic II Over I" (a non-seismic Category SSC whose failure could cause loss of safety function of a seismic Category I SSC). In addition, the staff requested that the applicant clarify how the aging management programs for the non-safety-related systems and components have been addressed. Specifically, the staff requested the applicant to state whether the same aging management programs discussed in Table 3.2.4 of the LRA also apply to the seismic II over I piping components. The applicant responded to these RAIs in its letter dated October 10, 2000. The applicant stated that the pipe supports for the seismic II over I piping systems are within the scope of license renewal and thus the supports for the seismic II over I piping systems are included within the scope of the aging management programs identified in the LRA. However, the applicant also stated that no aging management programs are applied to out-of-scope piping segments with seismic II over I piping supports. In a telephone conversation on October 24, 2000, the applicant further clarified this point. The applicant stated that within the context of the Plant Hatch licensing basis, non-safety-related piping systems are postulated to fall in a seismic event if not seismically supported. Thus, for the protection of safety-related piping, some non-safety-related piping is seismically supported. Those seismic supports are within the scope of license renewal, but the applicant does not consider the seismic II over I piping segments to be within the scope of license renewal. The staff does not agree with the applicant's scoping criteria for seismic II over I piping systems. The staff's position is that the seismic II over I piping whose failure could prevent safety-related systems and structures from accomplishing their intended functions should be within the scope of license renewal. The staff considers the seismic II over I piping segments to be within the scope of license renewal. This issue is also discussed in Section 3.6.3.2 of this SER.

Response to Open Item 2.1.3.1-1

On March 29, 2001 SNC met with NRC staff to discuss this open item. In that meeting, SNC made the following points:

- During scoping evaluations, SNC used the methodology described in Section 2.1 of the LRA based on the eight criteria found in the Rule to find that some piping systems performed no intended function.
- SNC found that many, if not all, of these piping systems in the reactor building had piping supports with analyses upgraded to Seismic Category I.
- The purpose of these supports, based on a review of the Hatch CLB, is to prevent the piping from falling on other objects, such as safety related piping.
- SNC brought these piping supports in scope since they performed an intended function - they prevent piping from falling on safety related equipment.

During the exchange of views in that meeting, an area of difference in understanding of the issue was revealed. SNC viewed the seismic II/I discussion to *only* include the issue of whether nonsafety-related pipes could fall on safety related components and prevent a safety related function. This view was based on a current licensing basis that treated other aspects of pipe failures such as flooding, spray, jet impingement, and pipe whip separately. By considering all those issues separately in the design and licensing of the plant, the seismic II/I label only retained the question of pipes falling. However, it also became apparent during the meeting that the NRC staff view of the seismic II/I label was that it included all the ancillary issues which the Hatch CLB had treated separately.

The request made of SNC by NRC staff in that meeting was to provide details of how these ancillary issues were addressed in the Hatch CLB within the context of license renewal. The following discussion is responsive to that request:

> Unit 2 FSAR section 3.2.1.1 defines Seismic Category I structures, components, and systems as those that perform an intended function following an accident to ensure that the requirements of 10 CFR 100 are met. Seismic Category II is defined as those structures, components, and systems whose failure would not result in the release of significant radioactivity and would not prevent reactor shutdown. All equipment not specifically listed as Seismic Category I is included as Seismic Category II. However, as stated in Unit 2 FSAR section 3.2.1.1, portions of nonseismic Category II systems are seismically supported if their failure could cause damage to Seismic Category I components. These are commonly referred to as Seismic II over I.
>
> In RAIs 3.4-11 and 3.6-51, the NRC questioned if the scope and AMPs for auxiliary systems discussed in Section 3.2.4 of the LRA included Seismic II over I piping segments. SNC responded that only the Seismic II over I pipe supports were included, not the piping segments between the supports. SNC stated that nonsafety-related piping systems are postulated to fall in a seismic event if not seismically supported. Therefore, aging effects for the pipe supports will be managed in the extended operating period to prevent the piping system from falling during a seismic event.
>
> In Open Item 2.1.3.1-1, the NRC disagreed that Seismic II over I piping segments could be excluded from the AMPs. The concern appeared to involve flooding, jet impingement, spray, and pipe whip due to pipe failure such as cracking, in addition to postulation of pipes falling on Seismic Category I components. The Plant Hatch CLB addresses these issues separate from the Seismic II over I issue.
>
> For auxiliary systems inside the primary containment, the Unit 1 FSAR section 5.2.2 and Appendix K.4, and Unit 2 FSAR sections 3.6 and 6.2.1.1, state that the primary containment is capable of withstanding jet forces from the postulated rupture of any pipe inside the containment. Analysis was performed and the systems were designed to withstand flooding, jet impingement, spray, and pipe whip from postulated pipe breaks. Therefore, the failure (i.e., loss of pressure boundary) of Seismic II over I piping segments between pipe supports has been evaluated and dispositioned.

For auxiliary systems located outside of the primary containment, the Unit 1 FSAR Appendix N, and Unit 2 FSAR section 15A, provide an analysis of the effects of high energy line breaks outside of containment and the ability to initiate and maintain a safe shutdown. Based on these analyses, the reactor can be placed and maintained in a safe shutdown condition, and the plant can withstand the effects of high energy line breaks outside of primary containment. Therefore, the failure (i.e., loss of pressure boundary) of Seismic II over I piping segments between pipe supports has been bounded by the high-energy line break analysis.

Inherent safety features to protect safety-related equipment from flooding, jet impingement, spray, and pipe whip have been included in the scope of license renewal. Safety-related equipment is located within Seismic Class I structures. All Class I structures, including internal walls, floors, ceilings, are in scope for license renewal. Therefore, protection from these events is provided as described below.

- Protection from jet impingement and spray is provided by these internal barriers as well as spray shields and pipe support frames. Spray shields are included with the building structural steel. Pipe support frames are included in function L35.
- Protection from pipe whip is provided by pipe whip restraints and pipe supports. These are included in function L35.
- Vent openings (including blowout panels) are provided if required by the pressure/temperature transient analysis for building compartments. Vent openings and blowout panels are included with the building structure.
- Relief vents are provided in the reactor and turbine roofs to prevent structural damage due to internal pressure. The relief vents are included in function T38.
- Protection from flooding is provided by curbs, walls, doors, and elevated platforms. These are included as part of the building structure.

Since portions of nonseismic Category II systems are seismically supported if their failure could cause damage to Seismic Category I components, and analyses were performed to ensure the reactor can be placed and maintained in a safe shutdown condition for pipe breaks inside or outside of primary containment, piping segments located between Seismic II over I supports do not require aging management.

During the March 29, 2001 meeting SNC stated that within the SNC view of seismic II/I, nonsafety-related pipes supported by supports analyzed to seismic category I requirements can not fall down. SNC went on to explain the CLB basis for that position as follows:

The Hatch design and licensing process reveals that the seismic margins analysis process employed by Hatch, and endorsed by NRC (EPRI NP-6041-SL, October 1988) states:

"Welded non-seismic piping should not be considered to sever and fall provided that the anchor points such as wall penetrations, pumps and tanks, do not fail. Past [structural integrity] design practices in the nuclear

> *industry have been to assume that non-seismic piping will sever and "rain down." Intermediate pipe supports may fail but ductile steel (not iron) pipes should not be considered to fall unless multiple support failures are possible in very long runs of pipe in open areas such as can be found in turbine bays."*

NUREG CR-6239 *"Survey of Strong Motion Earthquake Effects on Thermal Power Plants in California with Emphasis on Piping Systems,"* in section 4.5 states that in approximately two million feet of pipe, 99.8 % of which had not been seismically designed, which experienced earthquakes with peak ground acceleration in excess of 0.2g, the subject piping did not experience a single pipe segment fall. The experience data includes aged piping, since several of the plants surveyed had been in operation since the 1950's and 1960's.

Thus, with regard to nonsafety-related piping segments falling, SNC made the following points in the March 29 meeting:

- NO experience data exists of welded steel pipe segments falling due to a strong motion earthquake
- Falling of a piping system is extremely rare and only occurs when there is a failure or unzipping of the supports
- These observations hold for new and aged pipe

Based on a review of the CLB, SNC concludes that nonsafety-related piping must be supported in a manner to prevent it from falling on safety-related pipe in a seismic event in order to maintain the intended function of the safety related pipe. By design, nonsafety-related piping that could fall on safety related equipment was supported by pipe supports that were analyzed to Seismic Category I criteria. If those supports were to fail, a loss of intended function could occur. Thus, SNC brought those supports in scope. The Plant Hatch design has already considered other failure modes of the seismically supported nonsafety-related piping, such as flooding, spray, jet impingement, and pipe whip, so that there is no loss of intended function due to these other postulated failure modes.

In this response to the open item, and in response to NRC staff's request for additional information regarding how SNC treated postulated failures of nonsafety-related piping, SNC has shown that the consequences of the postulated failures were accommodated by design, and that these design considerations were appropriately brought within the scope of license renewal. SNC has also shown that within the context of the CLB and regulatory guidance implemented by Plant Hatch, the falling of seismically supported nonsafety-related piping segments should not be considered, and that postulation of such an event is hypothetical and not supported by empirical evidence. Thus, SNC maintains that nonsafety-related piping has been appropriately scoped in the Hatch LRA.

Open Item 2.3.3.2-1 (a)

In RAI-2.3.3-HR-1 and RAI-2.3.3-HR-4, the staff asked the applicant to justify its exclusion of the following components (highlighted in HL-26068) from an AMR: water separator, water spray cooler, reaction chamber, blower (C0001A), heater (B001A), and instrument tubing.

The staff believes that the water separator, water spray cooler, and reaction chamber are long-lived components with a passive function, and therefore are subject to an AMR. On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components performing a passive function associated with the hydrogen recombiners, and identify AMPs credited with managing the aging effects.

Response to Open Item 2.3.3.2-1 (a)

Based on discussions with NRC staff regarding this open item, the following information is provided for the hydrogen recombiner skid components, consistent with NRC guidance regarding the evaluation of skid-mounted assemblies.

In addition to the statements made on page 2.3-26 of the LRA, the following paragraph is added to the system description on that page:

> Some skid-mounted components form part of the containment pressure boundary during normal operation and testing, as well as during a response to an accident for which the recombiners must operate.

Consistent with NRC guidance regarding evaluation of skid-mounted assemblies, the following components are subject to an aging management review. These components are in addition to the components listed in Table 2.3.3-8 on page 2.3-27 of the LRA:

Mechanical Component	Component Functions	Material
Blower Casing	Pressure Boundary Fission Product Barrier	Carbon Steel
Instrumentation	Pressure Boundary Fission Product Barrier	Carbon Steel
Instrumentation	Pressure Boundary Fission Product Barrier	Stainless Steel
Piping	Pressure Boundary Fission Product Barrier	Stainless Steel
Reaction Chamber	Pressure Boundary Fission Product Barrier	Stainless Steel
Water Separator	Pressure Boundary Fission Product Barrier	Carbon Steel
Water Spray Cooler	Pressure Boundary Fission Product Barrier	Stainless Steel

Aging management reviews have been performed for the components listed in the above, three-column table. The following six-column table provides a summary of the results of those reviews. The components listed in this table are in addition to the components listed in Table 3.2.3-8 on page 3.2-30 of the LRA:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Blower Casing / C.2.2.9.1	Pressure Boundary, Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material, Cracking due to Thermal Fatigue	Passive Components Inspection Activities Gas System Components Inspections
Instrumentation / C.2.2.9.1	Pressure Boundary, Fission Product Barrier	Wetted Gas	Carbon Steel	Cracking due to Thermal Fatigue, Loss of Material	Gas System Components Inspections
Instrumentation / C.2.2.9.2	Pressure Boundary, Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking due to Thermal Fatigue, Loss of Material	Gas System Components Inspections
Piping / C.2.2.9.2	Pressure Boundary, Fission Product barrier	Wetted Gas	Stainless Steel	Cracking due to Thermal Fatigue, Loss of Material	Gas System Components Inspections
Reaction Chamber / C.2.2.9.2	Pressure Boundary, Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking due to Thermal Fatigue, Loss of Material	Gas System Components Inspections
Water Separator / C.2.2.9.1	Pressure Boundary, Fission Product Barrier	Wetted Gas	Carbon Steel	Loss of Material, Cracking due to Thermal Fatigue	Passive Components Inspection Activities Gas System Components Inspections
Water Spray Cooler / C.2.2.9.2	Pressure Boundary, Fission Product Barrier	Wetted Gas	Stainless Steel	Cracking due to Thermal Fatigue, Loss of Material	Gas System Components Inspections

Appendix C, section C.2.2.9.1 lists various components that comprise the commodity group on page C.2-114 of the LRA. In addition to the components in that list, the following components are also included in the commodity group of non-Class 1 Carbon Steel and Cast Iron Components in the Humid or Wetted Gases Environment:

- Instrumentation - Temperature Element and Flow Element (Pressure Boundary)
- Recombiner Blower Casing
- Recombiner Water Separator

Appendix C, section C.2.2.9.2 lists various components that comprise the commodity group on page C.2-118 of the LRA. In addition to the components in that list, the following components are also included in the commodity group of non-Class 1 Stainless Steel Components Containing Humid or Wetted Gases:

- Instrumentation -Temperature Element (Pressure Boundary)
- Recombiner Reaction Chamber
- Recombiner Water Spray Cooler

Open Item 2.3.3.2-1 (b)

[T]he staff requests that the applicant identify any applicable aging effects associated with [emergency diesel generator] components, and any other long-lived components with a passive function associated with the emergency diesel generators, and identify AMPs credited with managing the aging effects.

Response to Open Item 2.3.3.2-1 (b)

Based on discussions with NRC staff regarding this open item, the following information is provided for the emergency diesel generator skid-mounted components, consistent with NRC guidance regarding the evaluation of skid-mounted assemblies. This revised response includes resolution of comments provided by the staff during a May 14, 2001 telecon.

Most of the information provided in this response either revises, replaces, or is in addition to information initially provided in the LRA or in Appendix B. However, in some instances entire replacement pages are provided. The response provided by the April 17, 2001 e-mail submittal has been reformatted to clarify this information flow.

The reformatted response groups the information submitted by LRA or Appendix B sections. Section labels are provided to facilitate the review.

LRA Section 2.3.4.12

The information presented in this section is in addition to information already existing in the LRA, Section 2.3.4.12. The table provides additional line items and does not replace Table 2.3.4-12.

In addition to the statements made on page 2.3-50 of the LRA, the following paragraph is added to the system description on that page:

> "The diesel generators contain three subsystems that contain components that are passive, long-lived, and that perform a component function that supports the system intended function of Standby AC Power Supply (R43-01). These subsystems are the Diesel Jacket Water Cooling Subsystem, the Diesel Lubricating Oil Subsystem, and the Scavenging Air Subsystem. The evaluation boundary for the extended set of skid-mounted components ends at the engine block and does not include the active portion of the diesel."

Consistent with NRC guidance regarding evaluation of skid-mounted assemblies, the following components are subject to an aging management review. These components are in addition to the components listed in Table 2.3.4-12 on page 2.3-51 of the LRA:

Component	Component Functions	Material
Bolting	Pressure Boundary	Alloy Steel
Bolting	Pressure Boundary	Carbon Steel
Heater Housing	Pressure Boundary	Carbon Steel
Heat Exchanger Shell	Pressure Boundary, Heat Transfer	Carbon Steel
Heat Exchanger Tubes (Piping)	Pressure Boundary, Heat Transfer	Copper Alloy (90/10 Copper-Nickel or Admiralty Brass)
Piping / Tubing	Pressure Boundary	Copper
Pump Casing	Pressure Boundary	Carbon Steel
Restricting Orifice	Flow Restriction	Carbon Steel
Strainer Casing	Pressure Boundary	Carbon Steel
Strainer Element	Component Protection	Stainless Steel
Valve Bodies	Pressure Boundary	Cast Iron

LRA Section 3.2.4

The information presented in this section is in addition to information already existing in the LRA, Section 3.2.4. The table provides additional line items and does not replace Table 3.2.4-12.

Aging management reviews have been performed for the components listed in the above, three-column table. The following six-column tables provide a summary of the results of those reviews.

Based on staff comments provided in the May 14, 2001 telecon, commodity group numbers have been added to the line items in the tables. The initial response included stress corrosion cracking (SCC) as an aging effect requiring management for certain components in the three tables. During the telecon, NRC staff and SNC personnel discussed whether SCC was an aging effect requiring management for those components. Based on a review of the aging management review documents for those components, SNC has concluded that the stainless steel components fall below a temperature threshold needed for SCC to be considered as an aging effect requiring management. The copper alloy components are not in regular contact with ammonia and are therefore not subject to SCC. Therefore, SNC has removed reference to SCC from those components in the tables.

The initial submittal included diesel generator bolting in the list of components to be managed by the Diesel Generator Maintenance Activities (DGMA). During the telecon with the staff on May 14, 2001 SNC clarified that the manner in which DGMA would manage bolting was by invoking the torque activities. Since these activities are separately credited for aging management of in-scope bolting, SNC has revised the initial response to this open item to identify bolting as being managed by the torque activities and protective coatings programs, consistent with other in-scope bolting in the plant. The April 17, 2001 response to this open item was incorrect in the inclusion of cracking due to fatigue as an aging effect requiring management for the diesel generator bolting. These bolts are not subject to that cracking mechanism. This revised response has removed cracking due to fatigue as an aging effect requiring management for the bolting. This change is consistent with LRA appendix C.2.2.10 for non-class 1 pressure boundary bolting.

The components listed in these tables are in addition to the components listed in Table 3.2.4-12 on pages 3.2-45 and 3.2-46 of the LRA:

Jacket Water Cooling System

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Heater Housing (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Heat Exchanger Shell (C.2.2.12.1)	Pressure Boundary, Heat Transfer	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Copper	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Stainless Steel	Loss of Material, Cracking due to Fatigue,	Diesel Generator Maintenance Activities
Pump Casing (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Restricting Orifice (C.2.2.12.1)	Flow Restriction	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue,	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Brass	Loss of Material, Cracking due to Fatigue,	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Bronze	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Cast Iron	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Demin Water & antifreeze	Stainless Steel	Loss of Material, Cracking due to Fatigue,	Diesel Generator Maintenance Activities

Lubricating Oil Subsystem

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Filter Housing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Heater Housing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Heat Exchanger Shells (C.2.2.12.1)	Pressure Boundary, Heat transfer	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Copper	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Pump Casing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Strainer Casing (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Strainer Element (C.2.2.12.1)	Component Protection	Lube Oil	Carbon Steel	Loss of Material	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Lube Oil	Brass	Loss of Material, Cracking due to Fatigue,	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Lube Oil	Bronze	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Lube Oil	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Lube Oil	Cast Iron	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities

Heat Exchangers Components Containing Service Water or Air

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Bolting* (C.2.2.10.1)	Pressure Boundary	Moist Air	Alloy Steel	Loss of Material, Loss of Preload	Torque Activities, Plant Coatings Program
Bolting* (C.2.2.10.1)	Pressure Boundary	Moist Air	Carbon Steel	Loss of Material, Loss of Preload	Torque Activities, Plant Coatings Program
Heat Exchanger Shell (C.2.2.12.1)	Pressure Boundary, Heat transfer	Moist Air	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary, Heat Transfer	Raw Water	Admiralty Brass	Loss of Material, Loss of Heat Exchanger Performance, Cracking due to Fatigue,	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary, Heat transfer	Raw Water	Alloy: Copper-Nickel	Loss of Material, Loss of Heat Exchanger Performance, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Piping/Tubing (C.2.2.12.1)	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Pump Casing (C.2.2.12.1)	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Raw Water	Carbon Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Raw Water	Copper	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities
Valve Bodies (C.2.2.12.1)	Pressure Boundary	Raw Water	Stainless Steel	Loss of Material, Cracking due to Fatigue	Diesel Generator Maintenance Activities

* This commodity is present in all three of the subsystems as well as the heat exchangers. In each subsystem, the aging effects are the same. Therefore, bolting is presented once only, in this table, to minimize duplication.

LRA Appendix C, Section C.1.2.2

During the May 14, 2001 telecon, NRC staff requested that SNC provide an environment description for the diesel generator jacket water cooling subsystem, since the presence of ethylene glycol (anti-freeze) and corrosion inhibitors is not addressed in the demineralized water environment descriptions provided in LRA section C.1.2.2.

The following discussion provides a new paragraph to be included after the paragraph on borated water in LRA appendix C section C.1.2.2.

> "**Jacket Water Coolant** is contained within the jacket water cooling subsystem on the EDG skid. This fluid is a mixture of demineralized water and antifreeze. The antifreeze is an ethylene glycol solution that contains corrosion inhibitors and increases the thermal performance of the jacket water coolant. Detrimental impurities and conductivity are maintained at low levels but dissolved oxygen concentrations are not controlled or monitored."

Plant Hatch has reviewed the design basis of the EDGs and has determined that no specific vendor calculation exists under Plant Hatch control that evaluates thermal cycles of the piping and components on the EDG skid that are within the scope of License Renewal. While the 7000 thermal cycles normally evaluated in pipe stress analyses is adequate to envelope the operation of the EDGs, a TLAA is not available to use as an aging management program for the EDG skid-mounted components. The following text replaces the **Thermal fatigue** discussion on LRA page C.1-13 to address this distinction:

> "**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 (with the exception of the jacket water cooling subsystem of the EDGs) 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. For the jacket water cooling subsystem components there is no specific analysis under Plant Hatch control to demonstrate that thermal fatigue cracking is managed by design. For cracking in these components, the Diesel Generator Maintenance Activities provide adequate aging management."

LRA Appendix C, Section C.1.2.4

With regard to the EDG skid-mounted heat exchangers, thermal fatigue cracking of the copper alloy tubing is also not managed through a TLAA. Plant Hatch does not expect to see thermal fatigue cracking in the tubing. However, the DGMA are adequate to manage that aging effect. The following text replaces the **Thermal fatigue** discussion on LRA pages C.1-17 and -18 to address this distinction:

> "**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 (with the exception of the cooling tubes in the EDG skid-mounted heat exchangers) 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. For the cooling tubes in the EDG skid-mounted heat exchangers, there is no specific analysis under Plant Hatch control to demonstrate that thermal fatigue cracking is managed by design. For cracking in these components, the Diesel Generator Maintenance Activities provide adequate aging management."

LRA Appendix C, Section C.1.2.6

Similarly, thermal fatigue cracking of the components in the scavenging air subsystem of the EDGs is not managed through a TLAA. The following text replaces the **Thermal fatigue** discussion on LRA pages C.1-21 and -22 to address this distinction:

> "**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 (with the exception of the EDG skid-mounted components in the scavenging air subsystem) 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. For the scavenging air subsystem components, there is no specific analysis under Plant Hatch control to demonstrate that thermal fatigue cracking is

managed by design. For cracking in these components, the Diesel Generator Maintenance Activities provide adequate aging management."

New Appendix C, Section C.1.2.12

Lubricating oil was not described as an environment in the evaluation of aging effects requiring management contained in LRA appendix C.1. The following discussion provides a new appendix C section C.1.2.12 to discuss this environment.

C.1.2.12 Lubricating Oil

Lubricating oil is any oil utilized to lubricate the internal combustion engines of the diesel generators. 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 lubricating oil environment are discussed below.

C.1.2.12.1 Loss of Material within the Lubricating Oil Environment

Lubricating oils in their pure form are nonaggressive and noncorrosive to metals. However, intrusion of water contamination can create an aggressive environment within lubricating oil system components and additives to lubricating 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 inter-system leakage of service water is possible, a conservative estimate of the potential aging mechanisms is obtained. Refer to the raw water section (C.1.2.4) 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.1.2.12.2 Cracking Within the Lubricating 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. For the skid-mounted EDG components in the lubricating oil subsystem, there is no specific analysis under Plant Hatch control to demonstrate that thermal fatigue cracking is managed by design. For cracking in these components, the Diesel Generator Maintenance Activities provide adequate aging management.

LRA Appendix C, Section C.2.2.10

The bolting for the EDG skid-mounted piping connections is addressed through the Non-Class 1 Pressure Boundary Bolting Commodity in LRA section C.2.2.10. LRA appendix C, section C.2.2.10.1 is revised to include:

- R43 - Emergency Diesel Generator (2.3.4.12)

New Appendix C, Section C.2.2.12

In addition, a new Appendix C, section C.2.2.12 is provided on the following pages to present the results of the aging management reviews that are summarized in the six-column tables presented earlier in this response.

Based on discussions with NRC staff in the May 14, 2001 telecon, SNC has revised this section to include reference to the new Appendix C, section C.1.2.12 as applicable. A reference to LRA Appendix A was changed to Appendix B for the DGMA. Table C.2.2.12-1 has been revised to include reference to corrosion inhibitors and to optional eddy current testing. Finally, the operating experience discussion has been revised to more clearly indicate the nature of the operating experience with diesel generator heat exchanger tubes.

C.2.2.12 Emergency Diesel Generator Skid Components

This section includes an aging management evaluation for those components located on the diesel generator skids, but not included as part of the engine block or the active generator side of the engine. Several different materials are represented in these components as well as four environments: lubricating oil, demineralized water with anti-freeze solution, raw water, and moist inside air. The aging effects that require management in the renewal term for these components will all be managed with the same activities; therefore, these components are evaluated in the same commodity group.

C.2.2.12.1 Aging Management Review for Emergency Diesel generator Skid Components

The emergency diesel generator skid mounted components that are evaluated in this section support the diesel generator intended function of Standby AC Power Supply in two ways: keeping the engine well lubricated and keeping the engine cool. The three subsystems are:

- the scavenging air subsystem
- the lubricating oil subsystem
- the jacket water cooling system

The jacket water cooling system supplies the scavenging air heat exchanger and this heat exchanger is the only component of the scavenging air subsystem that has not been previously evaluated in the application. For the other two subsystems, the plant service water system (P41) supplies cooling water to the respective heat exchangers.

The evaluated components for the three subsystems include the following:

- Process piping and tubing – carbon steel
- Instrument tubing -- carbon steel, copper, and stainless steel
- Heat Exchanger Tubing – Copper-Nickel alloy and admiralty brass
- Process and drain valve bodies -- carbon steel, commercial bronze, commercial brass, cast iron
- Instrument valves – copper and stainless steel
- Pump casings – carbon steel
- Heat exchanger shells – carbon steel
- Filter housings – carbon steel
- Heater casings – carbon steel
- Strainer bodies – carbon steel
- Strainer elements – stainless steel
- Flow orifices – carbon steel
- Instrumentation – stainless steel and copper pressure boundary parts

Systems

- P41 – Service Water (2.3.4.7)
- R43 – Emergency Diesel Generators (2.3.4.12)

Aging Effects Requiring Management

- *Cracking* (C.1.2.1.2, C.1.2.4.2, and C.1.2.12.2) due to thermal fatigue.
- *Loss of Material* (C.1.2.1.1, C.1.2.4.1, and C.1.2.12.1) due to general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and wear.
- *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.

Programs to Manage Aging Effects

- Diesel Generator Maintenance Activities

A complete discussion of the applicable aging management programs may be found in Appendix B, section B.1.18.

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. With regard to cracking due to thermal fatigue, even though no significant thermal cycling is expected, Plant Hatch has determined that cracking due to thermal fatigue for components in the subsystems of the diesel generators is adequately addressed through the normal maintenance activities for the diesels. In addition, the normal diesel generator maintenance activities are performed in such a fashion as to discover fatigue cracking prior to failure of the subsystems.

The Diesel Generator Maintenance Activities encompass a broad spectrum of maintenance activities and performance testing designed to ensure the operational readiness of the emergency diesel generators in accordance with Technical Specifications.

These activities include regular preventative maintenance for individual skid mountain components including the pumps, filters, heaters, thermostatic control valves and heat exchangers. The diesel generators have many performance tests, including monthly, semi-annual, and eighteen-month tests. The combination of these performance tests and maintenance activities with the Corrective Actions Program is sufficient to manage the applicable aging effects. Table C.2.2.12-1 describes how these two programs are effective in managing the component aging effects.

Review of Operating Experience

A review of the condition reporting database revealed several occasions where the cooler tubes required replacement or repair for excessive loss of material up to and including leakage of the tubes. The corrective actions were accomplished prior to a loss of system intended function. In addition, performance deficiencies were identified with the AMOT thermostatic flow control valves where the valves leaked passed the valve seat or were not otherwise performing their temperature control function adequately. Neither loss of material nor cracking in the valve body caused these performance deficiencies. The deficiencies were not the same as those described in NRC IN 91-85, and the valves were replaced or refurbished prior to a loss of system intended function.

Table C.2.2.12-1 Aging Management Program Assessment for Diesel Generator Skid-Mounted Equipment

Attributes	Aging Management Program/Procedure
1. Scope of the program includes the specific structure, component or commodity for the identified aging effect.	The Diesel Generator Maintenance Activities govern aging management the components included within this plant commodity group.
2. Preventive actions to mitigate or prevent aging degradation.	The Diesel Generator Maintenance Activities minimize age related degradation by ensuring the quality of the lube oil and by including ethylene glycol with corrosion inhibitors in the demineralized water used in the Jacket Water Cooling subsystem. Performance tests can identify detrimental aging effects under controlled conditions before an accident or transient condition would require the EDGs to perform. The use of sacrificial anodes to limit galvanic corrosion also acts as a preventive measure.
3. Parameters monitored or inspected are linked to the degradation of the particular intended function.	The Diesel Generator Maintenance Activities monitor performance data such as flow rates and temperatures of the in-scope subsystems. Lube oil is monitored through testing for wear and corrosion products and for water.
4. The method of detection of the aging effects is described and performed in a timely manner.	The Diesel Generator Maintenance Activities provide for periodic performance monitoring and inspections designed to detect degradation of components. The performance tests will detect detrimental degradation prior to the actual need for the EDGs to perform their intended functions. The DGMA include optional eddy current testing of EDG skid-mounted heat exchanger tubes.
5. Monitoring and trending for timely corrective actions.	For degradation of components within this plant commodity group, the Diesel Generator Maintenance Activities provide for testing of lube oil for wear and corrosion products and water. This data can be trended.
6. Acceptance criteria are included.	The Diesel Generator Maintenance 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 and the Diesel Generator Maintenance 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.

Appendix B, Section B.1.18

During the May 14, 2001 telecon, various ways of presenting the DGMA information were discussed with a view towards more clearly linking the various activities with the ten attributes for aging management programs. The following pages are submitted in response to that discussion and replace the Appendix B.1.18 pages provided in the April 17, 2001 submittal.

B.1.18 DIESEL GENERATOR MAINTENANCE ACTIVITIES

The Diesel Generator Maintenance Activities (DGMA) provide for management of the applicable aging effects (loss of material, cracking, loss of heat exchanger performance, and loss of bolting preload) for the in-scope emergency diesel generator (EDG) components.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect)

The DGMA are existing activities that address the aging effects for the emergency diesel generator skid-mounted components within the jacket water cooling, lubricating oil, and scavenging air subsystems that are within the boundaries of the EDG skid. The EDGs for both units are included in these activities. The components are limited to the piping, tubing, restricting orifices, valve bodies, pump casings, heat exchangers, heater casings, filter housings, strainer bodies, and strainer elements.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation)

The DGMA are a collection of performance monitoring activities and preventive maintenance activities that ensure that the Technical Specifications for Plant Hatch are met with regard to the EDGs. The DGMA apply preventive maintenance to in-scope components in all three subsystems on the EDG skid.

Preventive or mitigative DGMA include inspections of the EDG components and evaluations of the jacket water system fluid and the lubricating oil. The inspections are visual, chemical, and also performance based. In addition, the jacket water coolant contains antifreeze with corrosion inhibitors.

The DGMA include visual inspections of the EDG components during maintenance. The DGMA also include the option for eddy current testing of the heat exchanger tubes (exposed to raw water) on an as-desired basis. These inspections and tests are designed to identify aging effects before they inhibit system performance.

Replacement of adversely affected components (and fluids, such as the jacket cooling water and lubrication oil) is also an option.

The DGMA are performed at various frequencies depending upon the task. Major preventative maintenance activities on the EDGs currently are performed on a cycle corresponding to plant refueling outages. Surveillance performance tests are performed more frequently, as prescribed in the Plant Hatch Technical Specifications surveillance requirements.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function)

Fluid conditions on the EDG skid are evaluated and monitored. The jacket water coolant is evaluated for the quality and the amount of antifreeze in the solution. Lubricating oil is tested for wear products, water, fuel oil, and anti-freeze. Oil tests are compared to previous tests. The chemical properties of the lubricating oil are monitored to ensure that the lubricating oil subsystem can perform to maintain EDG operability.

The DGMA visually inspect the heat exchanger water boxes, tubes, tube sheets, and sacrificial zinc rods for damage, debris, deposits and corrosion. The optional eddy current testing evaluates the heat exchanger tube walls for defects and wall thickness.

The DGMA monitor EDG performance such that the Technical Specifications are met.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner.)

The DGMA include regular, frequent, performance surveillance tests of the EDGs to ensure that technical specification performance requirements are met. The DGMA preventive maintenance activities occur frequently (e.g., during EDG system outages). During these tests and maintenance activities, aging effects (cracking, loss of material, and loss of heat exchanger performance) that could adversely impact the performance of the EDG component intended functions would be identified.

Evidence of corrosion or wear products in the lubricating oil is determined through chemical analysis. Loss of material can be identified through this analysis.

The DGMA can detect loss of heat exchanger performance in the heat exchangers through pressure and temperature instrumentation during the performance tests. Visual inspections during maintenance of the heat exchangers can detect loss of material due to corrosion of the heat exchanger shells. The eddy-current tests have proved useful in identifying loss of material in the heat exchanger tubes.

DGMA are not intended to directly detect loss of material or cracking within all of EDG components in the jacket water cooling and scavenging air subsystems. The preventive and mitigative actions performed by this activity are sufficient such that this attribute is not required for those aging effects in those subsystems.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Chemical analysis data for the lubrication oil is maintained such that wear and corrosion products are detected and trended. Inspection and performance data for the heat exchangers is maintained in plant records. The mitigative performance testing and preventive maintenance actions performed by the DGMA are sufficient such that additional trending is not required.

Acceptance Criteria

(Acceptance Criteria are included.)

For performance tests, the acceptance criteria are listed in the specific plant procedures and are intended to ensure that system operating temperatures, pressures, and expansion tank levels are within the acceptable operating ranges. For preventative maintenance activities, the acceptance criteria are also contained within the maintenance procedures and are commensurate with the safety significance of the component inspected. After maintenance, the performance of the components must be such that the performance test criteria are satisfied. No industry codes or standards apply to this activity.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of the condition reporting database revealed several occasions where the cooler tubes required replacement or repair for excessive loss of material up to and including leakage of the tubes. The corrective actions were accomplished prior to a loss of system intended function. In addition, performance deficiencies were identified with the AMOT thermostatic flow control valves where the valves leaked passed the valve seat or were not otherwise performing their temperature control function adequately. Neither loss of material nor cracking in the valve body caused these performance deficiencies. The deficiencies were not the same as those described in NRC IN 91-85, and the valves were replaced or refurbished prior to a loss of system intended function.

Open Item 2.3.3.2-2 (a), (c), (d)

(a) The staff requests that the applicant identify the passive functions for those fans, dampers, and heating and cooling coils that are within the scope of license renewal. For those passive functions, the applicant should identify any aging effects associated with the components and provide an AMP to manage the aging. The applicant also agreed to clarify the function of the guillotine damper regarding whether this damper is safety-related and included in the scope of license renewal and subject to an AMR.

(c) In its response to RAI 2.3.4-OSHVAC-1, the applicant stated that roof-mounted exhaust ventilator housings and wall-mounted unit heater housings are not subject to an AMR, since these housings are part of active components (i.e., fan/damper assembly and heater for each, respectively). The staff disagrees with the applicant's exclusion from an AMR of roof-mounted exhaust ventilator and wall-mounted unit heater housings. The staff's position with regard to the treatment of the housings for roof-mounted exhaust ventilators and wall-mounted unit heaters is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER also applies to the treatment of the component passive functions of the outside structures HVAC system.

(d) In its response to RAI 2.3.4-RBHVAC-1, the applicant stated that safeguards equipment room cooler housings are not subject to an AMR, based on NEI 95-10, Appendix B guidance. With regard to this RAI, the applicant also did not address the scope of license renewal and an AMR as relates to air-operated valve bodies, air-operated damper housings, and associated ductwork. Additionally, in a telephone conference (telecon) held on October 31, 2000, the applicant agreed to reconsider its response to RAI 2.3.4-RBHVAC-3, concerning whether certain ductwork identified by the staff is within the scope of license renewal and is subject to an AMR.

The staff believes that the safeguards equipment room cooler housings may be within the scope of license renewal and subject to an AMR. The staff's position with regard to the treatment of the housings for the safeguards equipment room coolers is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER applies to the treatment of the component passive functions of the reactor building HVAC system. Resolution of this issue, including the scoping clarification for the air-operated valve bodies, air-operated damper housing, and associated ductwork, is part of this open item.

Response to Open Item 2.3.3.2-2 (a), (c), (d)

This revised response addresses topics discussed in a May 16, 2001 telecon with NRC staff. In addition, minor reformatting of the initial response has been performed to facilitate the review.

Based on discussions with NRC staff during the meeting on March 29, 2001, SNC provides the following information regarding the disposition of fans, dampers, and heating and cooling coils within the scope of license renewal for Plant Hatch. The response to part (b) of this open item is provided separately.

LRA Section 2.3.3.6

In LRA section 2.3.3.6 Standby Gas Treatment System [T46], the first sentence of the second paragraph on page 2.3-22 is revised to state "The major components of the SGTS include redundant filter trains, control valves, air-operated and backdraft dampers, fans, and control instrumentation."

Consistent with NRC guidance regarding evaluation of active components, the following components are subject to aging management review because portions of the components have a passive function that supports a passive system intended function.

The following components are in addition to the components listed in Table 2.3.3-6 on page 2.3-23 of the LRA for components supporting Standby Gas Treatment System [T46] intended functions:

Mechanical Component	Component Functions	Material
Damper (frame only)	Fission Product Barrier Pressure Boundary	Carbon Steel
Fan Housing	Fission Product Barrier Pressure Boundary	Carbon Steel

LRA Section 2.3.3.7

The following component is in addition to the components listed in Table 2.3.4-7 on page 2.3-41 of the LRA for components supporting Plant Service Water System [P41] intended functions:

Mechanical Component	Component Functions	Material
Cooling Coil Tubing	Pressure Boundary	Copper Alloy

LRA Section 2.3.4.15

The following components are in addition to the components listed in Table 2.3.4-15 on page 2.3-58 of the LRA for components supporting Reactor Building HVAC System [T41] intended functions:

Mechanical Component	Component Functions	Material
Damper (frame only)	Pressure Boundary	Carbon Steel
Fan Housing	Pressure Boundary	Carbon Steel
Fan Inlet Housing	Pressure Boundary	Aluminum
Fan Inlet Screen	Protection from Debris	Aluminum

LRA Section 2.3.4.17

The following components are in addition to the components listed in Table 2.3.4-17 on page 2.3-63 of the LRA for components supporting Outside Structures HVAC System [X41] intended functions:

Mechanical Component	Component Functions	Material
Damper (frame only)	Pressure Boundary	Carbon Steel
Fan Housing	Pressure Boundary	Carbon Steel
Unit Heater Housing	Flow Direction	Carbon Steel

LRA Section 2.3.4.18

The following component is in addition to the components listed in Table 2.3.4-18 on page 2.3-66 of the LRA for components supporting Fire Protection System [X43] intended functions:

Mechanical Component	Component Functions	Material
Fire Dampers	Pressure Boundary Fire Barrier	Carbon Steel

LRA Section 2.3.4.20

The following components are in addition to the components listed in Table 2.3.4-20 on page 2.3-71 of the LRA for components supporting Control Building HVAC [Z41] intended functions:

Mechanical Component	Component Functions	Material
Condensing Unit Shell	Pressure Boundary	Carbon Steel
Condensing Unit Shell	Pressure Boundary	Gray Cast Iron
Damper (frame only)	Pressure Boundary	Carbon Steel
Damper (frame only)	Pressure Boundary	Gray Cast Iron
Fan Housing	Pressure Boundary	Aluminum
Fan Housing	Pressure Boundary	Carbon Steel
Fan Housing	Pressure Boundary	Galvanized Steel
Fan Screen	Protection from Debris	Carbon Steel

LRA Section 3 Tables

Aging management reviews have been performed for the components listed in the above, three-column tables. The following six-column tables provide summaries of the results of those reviews.

In a May 16, 2001 telecon with SNC, NRC staff asked for clarification regarding whether loss of heat exchanger performance was an aging effect for the cooling coil tubing. Loss of heat exchanger performance is considered an aging effect requiring management for the cooling coil tubing identified in the Table 3.2.4-15 line item entries for components supporting Reactor Building HVAC System [T41] intended functions, and Table 3.2.4-20 for components supporting Control Building HVAC System [Z41] intended functions.

During the telecon NRC staff noted the occasional use of "inside" as an environment where "air" might have been expected in Tables 3.2.4-15, 3.2.4-17, and 3.2.4-20. The label "inside" was selected for these components since they see humid air on the exterior and conditioned air on the interior. The selection of "inside" was made in order to assure that the more humid air environment on the exterior of the components was identified as the controlling environment.

LRA Section 3.2.3

The components in the following table are in addition to the components listed in Table 3.2.3-6 on pages 3.2-26 and 27 of the LRA for components supporting Standby Gas Treatment System [T46] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Damper (frame only) / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activity
Fan Housing / C.2.2.9.1	Fission Product Barrier Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activity

LRA Section 3.2.4

The component in the following table is in addition to the components listed in Table 3.2.4-7 on pages 3.2-38 - 40 of the LRA for components supporting Plant Service Water System [P41] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Cooling Coil Tubing / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Flow Blockage	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program

The components in the following table are in addition to the components listed in Table 3.2.4-15 on page 3.2-49 of the LRA for components supporting Reactor Building HVAC System [T41] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Cooling Coil Tubing / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Loss of Material Cracking Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program
Damper (frame only) / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activity
Fan Housing / C.2.2.9.1	Pressure Boundary	Wetted Gas	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activity
Fan Inlet Housing / C.2.2.9.4	Pressure Boundary	Air	Aluminum	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activity
Fan Inlet Screen / C.2.2.9.4	Protection from Debris	Inside	Aluminum	Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activity

The components in the following table are in addition to the components listed in Table 3.2.4-17 on page 3.2-51 of the LRA for components supporting Outside Structures HVAC System [X41] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Damper (frame only) / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Fan Housing / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities
Unit Heater Housing / C.2.2.9.1	Flow Direction	Inside	Carbon Steel	Loss of Material Cracking	Gas Systems Component Inspections Passive Component Inspection Activities

The component in the following table is in addition to the components listed in Table 3.2.4-18 on pages 3.2-53 - 55 of the LRA for components supporting Fire Protection System [X43] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Fire Damper / C.2.3.4.1	Pressure Boundary Fire Barrier	Air	Carbon Steel	Cracking Loss of Material	Fire Protection Activities

The components in the following table are in addition to the components listed in Table 3.2.4-20 on pages 3.2-58 and 59 of the LRA for components supporting Control Building HVAC System [Z41] intended functions:

Mechanical Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Damper (frame only) / C.2.2.9.1	Pressure Boundary	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Damper (frame only) / C.2.2.9.1	Pressure Boundary	Air	Gray Cast Iron	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Fan Housing / C.2.2.9.4	Pressure Boundary	Air; Wetted	Aluminum	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Fan Housing / C.2.2.9.1	Pressure Boundary	Air; Wetted	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Fan Housing / C.2.2.9.4	Pressure Boundary	Air; Wetted	Galvanized Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Condensing Unit Shell / C.2.4.1	Pressure Boundary	Inside	Carbon Steel	Cracking Loss of Material	Protective Coatings Program
Condensing Unit Shell / C.2.2.6.4	Pressure Boundary	Raw Water Dried Gas	Gray Cast Iron	Cracking Loss of Material	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program
Condensing Unit Tubing / C.2.2.6.3	Pressure Boundary	Raw Water	Copper Alloy	Cracking Loss of Material Loss of Heat Exchanger Performance	PSW and RHRSW Inspection Program PSW and RHRSW Chemistry Control Program
Fan Screen / C.2.2.9.1	Protection from Debris	Air	Carbon Steel	Cracking Loss of Material	Gas Systems Component Inspections Passive Component Inspection Activities
Flow Element / C.2.2.9.2	Pressure Boundary	Air	Stainless Steel	Cracking	None Required

During the May 16, 2001 telecon, the NRC staff observed that the stainless steel flow element in Table 3.2.4-20 did not identify loss of material as an aging effect requiring management, even though the corresponding aging management review section, C.2.2.9.2, does list loss of material as an aging effect for the environment. In stainless steel, the mechanisms that can cause loss of material are only significant if pooling or ponding of water occurs. The design of the flow element precludes pooling or ponding of moisture. Thus, loss of material was not selected as an aging effect requiring management for this component.

LRA Appendix C.1.2.4.4

The inclusion of loss of heat exchanger performance as an aging effect requiring management for the cooling coil tubing identified in the response to this open item results in a *pro forma* change in Appendix C.1.2.4.4 to note the inclusion of the coolers. The following revised wording replaces the text in Appendix C.1.2.4.4 on page C.1-19 of the LRA.

> "See section C.2.2.11.1 for the aging management review of the RHR system heat exchangers and section C.2.2.6.3 for the aging management review of coolers and condensing units.
>
> **Fouling** - All of the fouling types described in section C.1.2.4.3 are applicable to the coolers, condensing units and RHR heat exchangers. Any buildup of material on heat exchange surfaces will result in some loss of heat exchanger performance."

LRA Appendix C.2.2.6.3

Appendix C, section C.2.2.6.3 lists various components that comprise the commodity group on page C.2-97 of the LRA. Instrumentation tubing was identified on that list. As discussed during a telecon on May 1, 2001, copper tubing is identified as tubing, cooling coil tubing and condensing unit tubing in the various related parts of the LRA and in this response. Thus, instead of instrumentation tubing, the following component description is provided in the commodity group of non-Class 1 Copper Alloys Within the River Water Environment to represent all types of copper tubing:

- Tubing

The list of systems with components in this environment is revised to include the following systems:

- T41 – Reactor Building HVAC (2.3.4.15)
- Z41 – Control Building HVAC (2.3.4.20)

Consistent with the May 16, 2001 telecon discussions on loss of heat exchanger performance, the list of aging effects requiring management in this environment is revised to include the following aging effect:

- Loss of Heat Exchanger Performance (C.1.2.4.4) due to fouling.

LRA Appendix C.2.2.6.4

Appendix C, section C.2.2.6.4 lists various components that comprise the commodity group on page C.2-101 of the LRA. In addition to the components in that list, the following component is also included in the commodity group of non-Class 1 Gray Cast Iron Components Within the River Water Environment:

- Condensing unit shell

The list of systems with components in this environment is revised to include the following system:

- Z41 – Control Building HVAC (2.3.4.20)

LRA Appendix C.2.2.8.1

Appendix C, section C.2.2.8.1 lists various components that comprise the commodity group on page C.2-111 of the LRA. In addition to the components in that list, the following component is also included in the commodity group of non-Class 1 Carbon Steel Components in the Dry Compressed Gas Environment:

- Condensing unit shell

LRA Appendix C.2.2.9.1

Appendix C, section C.2.2.9.1 lists various components that comprise the commodity group on page C.2-114 of the LRA. In addition to the components in that list, the following components are also included in the commodity group of non-Class 1 Carbon Steel and Cast Iron Components in the Humid or Wetted Gases Environment:

- Unit heater housings
- Fan housings
- Fan screen
- Damper frames

The list of systems with components in this environment is revised to include the following systems:

- T41 – Reactor Building HVAC (2.3.4.15)
- Z41 - Control Building HVAC (2.3.4.20)

LRA Appendix C.2.2.9.2

Appendix C, section C.2.2.9.2 lists various components that comprise the commodity group on page C.2-118 of the LRA. In addition to the components in that list, the following component is also included in the commodity group of non-Class 1 Stainless Steel Components Containing Humid or Wetted Gases:

- Flow element

LRA Appendix C.2.2.9.4

Appendix C, section C.2.2.9.4 lists various components that comprise the commodity group on page C.2-126 of the LRA. In addition to the components in that list, the following components are also included in the commodity group of non-Class 1 Galvanized Carbon Steel and Aluminum Components Containing Humid or Wetted Gases:

- Fan housing
- Fan inlet housing
- Fan inlet screen

LRA Appendix C.2.3.4.1

The title of Appendix C, section C.2.3.4.1 is revised to read "Fire Penetration Seals and Fire Dampers." The first sentence of the section is revised to read "Fire penetration seals and fire dampers are assemblies fabricated from combinations of the following materials:" In the aging effects requiring management section, for loss of material, the sentence is revised to read "*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 frames and wear or fretting of fiber and ceramic materials." For cracking, the sentence is revised to read "*Cracking* (C.1.2.11.2 and C.1.4.1) of carbon steel sleeves and frames due to fatigue, and of fiber, ceramic, and foam materials due to thermal degradation." A new section is added before the *Review of Operating Experience*. The new section reads:

> ***Management of Degradation of Fire Dampers***
> *Fire Protection Activities* provide for visual inspections and functional testing of fire dampers. These inspections and tests occur at regular intervals and are adequate to detect degradation of fire dampers prior to any loss of intended function.

Appendix B, Section B.1.4

Appendix B, section 1.4 lists systems associated with the Plant Service Water and RHR Service Water Chemistry Control program. In addition to the systems listed on page B.11, the following systems are included:

- T41 - Reactor Building HVAC (2.3.4.15)
- Z41 - Control Building HVAC (2.3.4.20)

Appendix B, Section B.1.13

Based on the May 16, 2001 telecon, the PSW and RHRSW Inspection program discussion is revised to include loss of heat exchanger performance. The first paragraph of the program is reproduced below.

> "Passive components associated with the PSW and RHRSW could potentially be adversely affected by aging mechanisms, such that loss of material, loss of heat exchanger performance, flow blockage, and cracking (of RHR heat exchanger tubes) could occur during the extended period of operation. This program is designed to detect wall thickness degradation, fouling or cracking in the PSW and RHRSW systems. The specific inspection locations in the PSW and RHRSW systems are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are infrequently used piping (stagnation water), submerged piping, piping with low fluid velocity, small diameter piping, backing rings, socket welds, and heat affected zone of a weld. 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. Locations prone to cracking include locations susceptible to vibration fatigue and stress corrosion cracking (RHR heat exchanger tubes). Locations prone to erosion include the areas with high velocity."

The aging management program description for the PSW and RHRSW Inspection Program, section B.1.13, is revised to add the following systems to the Program Scope section:

- T41 - Reactor Building HVAC (2.3.4.15)
- Z41 - Control Building HVAC (2.3.4.20)

The second paragraph of the Monitoring and Trending section is reproduced below, with revised wording to include the cooling coils and condensing unit tubes.

> "For RHR heat exchanger components the visual inspection frequency is every three cycles but may be revised based on observed trends. Visual inspections will also be performed on the ECCS room cooling coils and control room condensing unit tubes at a frequency prescribed by the individual procedures."

FSAR Supplement Section 18.2.4

A *pro forma* change was made to the PSW and RHRSW Chemistry Control section to correspond to the addition of "loss of heat exchanger performance" in Tables 3.2.4-15 and 3.2.4-20. The revised FSAR supplement pages are included in the response to open item 3.0-1.

FSAR Supplement Section 18.2.13

Pages 18.2-15 and -16 in the response to open item 3.0-1 incorporate *pro forma* changes to the FSAR supplement program description for the PSW and RHRSW Inspection Program consistent with the changes made in Appendix B described above. These changes add discussion of the cooling coils and condensing unit tubes.

Responses to NRC's April 26, 2001 Comments on SNC's April 17, 2001 Response to Open Item 2.3.3.2-2 (a), (c), (d)

By an April 26 e-mail, NRC provided comments regarding the April 17, 2001 response to the open item. These items were discussed on May 1, 2001 in a telecon. The following discussion is provided consistent with that telecon. The preceding revised response incorporates corrections noted in the responses to comments.

Comment 1:

Tables 2.3.4-15 (p. 20 of the open item response) and 3.2.4-15 (p. 23) don't agree. Cooling coil tubing is identified on 3.2.4-15 but not on 2.3.4-15. Also, p. 26 states that unit heater housings should be added to LRA Section C.2.2.9.1, but this component is not identified in either table.

Response 1:

Copper alloy tubing was already included in Table 2.3.4-15 of the LRA. The unit heater housings are associated with System X41 and are identified in Tables 2.3.4-17 and 3.2.4-17.

Comment 2:

Tables 2.3.4-20 (p. 21) and 3.2.4-20 (p. 25) don't agree. The cooling coil tubing that is discussed on p. 26 is not identified in either table. Also, Table 3.2.4-20 includes condensing unit tubing and a flow element, but Table 2.3.4-20 does not.

Response 2:

Copper tubing was already included in Table 2.3.4-20 of the LRA. Cooling coil tubing is included in the copper tubing entry shown on both tables. Condensing unit tubing is shown in Table 2.3.4-20 as copper tubing and the flow element is shown on the same table as the stainless steel flow element.

Comment 3:

Referring to p. 23, should the reference for fan housings in Table 3.2.4-15 be C.2.2.9.4 instead of C.2.2.9.1 to be consistent with p. 27?

Response 3:

No, the fan housings in Table 3.2.4-15 are painted carbon steel. The correct aging management section should therefore be C.2.2.9.1, "AMR for non-Class 1 Carbon Steel and Cast Iron Components in the Humid or Wetted Gases Environment." See also the response to comment 6.

Comment 4:

On page 26, Gas Systems Component Inspections (GSCI) and Passive Component Inspection Activities (PCIA) should be added to C.2.2.6.4 of the LRA since they are credited with managing aging for non-Class 1 gray cast iron components in a river water environment (see p.25).

Response 4:

No, the correct AMPs for the gray cast iron condensing shell shown on Table 3.2.4-20 (Page 25 of the April 17, 2001 response) are the PSW and RHRSW Inspection Program and the PSW and RHRSW Chemistry Control Program.

Comment 5:

On page 26, GSCI and PCIA should be added to C.2.2.8.1 of the LRA since they are credited with managing aging for carbon steel components in a dried gas environment.

Response 5:

No, the correct environment shown on Table 3.2.4-20 should have been "Inside" which is managed by the Protective Coatings Program (Section C.2.4.1).

Comment 6:

On p. 25, Table 3.2.4-20 lists C.2.2.9.1 for aluminum fan housings, but this material is not discussed in C.2.2.9.1.

Response 6

The correct LRA section reference should be C.2.2.9.4, not C.2.2.9.1.

Comment 7:

On p. 25, Table 3.2.4-20 lists C.2.2.8.1 for the carbon steel condensing unit shell. It states that loss of material is the applicable aging effect and that GSCI and PCIA are the AMPs credited with managing the aging. However, none of this is discussed in C.2.2.8.1.

Response 7:

The correct section for aging management for this component should be C.2.4.1, not C.2.2.8.1. See also the response to comment 4.

Comment 8:

On p.25, Table 3.2.4-20 lists C.2.2.6.4 for the gray cast iron condensing unit shell. It states that GSCI and PCIA are the AMPs credited with managing aging in these components, but they are not identified in C.2.2.6.4.

Response 8:

The correct AMPs are PSW and RHRSW Inspection Program and the PSW and RHRSW Chemistry Control Program, not GSCI and PCIA. See also the response to comment 5.

Comment 9:

System X43-Fire Protection, should be added to AMP B.3.3 for GSCI, since it has been added to C.2.2.9.1.

Response 9:

As discussed in the telecon, the commodity group reference for the fire dampers in Table 3.2.4-18 was changed from the general carbon steel commodity group (C.2.2.9.1) to the proper fire protection-specific commodity group (C.2.3.4.1) prior to submitting the April 17, 2001 responses. However, a conforming change was not made on page 27 of that package to remove X43 - Fire Protection from the list. Since the fire protection components are managed by fire protection activities, the system does not need to be added to AMP B.3.3 (GSCI).

Comment 10:

System Z41-Control Building HVAC, should be added to AMP B.1.4, since it's added to C.2.2.6.4.

Response 10:

SNC agrees. The related Appendix B page revision is noted in the revised response to this open item.

Comment 11:

System T41-Reactor Building HVAC, should be added to B.1.4, since it's added to C.2.2.6.3.

Response 11:

SNC agrees. The related Appendix B page revision is noted in the revised response to this open item.

Comment 12:

Is the fan housing that is identified in Table 2.3.4-17 on p. 20 and Table 3.2.4-17 on p. 23 intended to cover the roof-mounted exhaust ventilator housing identified in part (c) of Open Item 2.3.3.2-2?

Response 12:

Yes. The carbon steel fan housing indicated on the referenced tables does represent the 'roof-mounted' exhaust ventilator housings from Part (c) of the open item. Since the fan housing is actually mounted within the concrete roof structure, the internal environment indicated on Table 3.2.4-17 is air.

Comment 13:

The open item response did not address the staff question regarding the guillotine damper that was discussed in part (a) of Open Item 2.3.3.2-2.

Response 13:

The staff's question regarding the guillotine dampers is related to RAI 2.3.3-SGTS-1(f). As expressed in Open Item 2.3.3.2-2, the request was for SNC to clarify the function of the guillotine dampers, 2T46-F111 and 2T46-F112, regarding whether the dampers are safety-related and included in the scope of license renewal and subject to an AMR.

The dampers represent a commodity group of dampers associated with SGTS filtration units, 2T46-D001A and 2T46-D001B, shown on HL-26078 (Zones C4 and G4). During accident and normal operating conditions, the dampers remain open. For filter testing purposes the dampers may be closed as needed. However, the guillotine dampers are not safety-related, do not perform an intended function and can not prevent an intended function.

Open Item 2.3.3.2-2 (b)

In a telephone conference (telecon) held on October 31, 2000, the applicant clarified that the LPCI inverter room and the Unit 2 vital A/C room coolers are no longer in scope due to a design modification. The applicant committed to provide a description of the design modification that clarifies how the modification impacts the LPCI inverter room and Unit 2 vital A/C room functions. The applicant also committed to address why heating coil housings are not specifically identified in Table 2.3.4-20 of the LRA.

Response to Open Item 2.3.3.2-2 (b)

The LPCI inverters (R44) were originally installed to provide power for certain LPCI valves independent of their Class 1E AC power supplies. By supplying 1E power to these valves, the LPCI inverters met the criteria established in Part 54.4 of the Rule for inclusion in license renewal scope. However, over a period of time, the LPCI inverters became obsolete. Plant design change packages retired the Unit 1 and Unit 2 LPCI inverters. To continue to provide a diverse source of power for the valves, Unit 2 Class 1E AC power supplies were selected as the normal source of power for the Unit 1 LPCI valves. Likewise, Unit 1 Class 1E AC power supplies were selected as the normal source of power for the Unit 2 LPCI valves. Buses supplied by the 1B diesel served as an emergency backup for both units. These design changes were completed prior to submittal of the LRA. The LPCI inverter function (R44-02) was removed from scope when the modifications were performed to remove the inverters, effectively deleting the function. Therefore, the function was not included in the LRA. A support function, LPCI inverter room essential cooling function (Z41-01) was also not included in scope for license renewal as shown on Table 2.2-1 of the application. The presentation of this information was inconsistently applied in the LRA. In one case (R44-02) the function was removed without a footnote in Table 2.2-1. In the other case (Z41-01), the function was deleted but the function was listed in the table with a footnote indicating the function no longer existed.

The following discussion clarifies the October 31, 2000 telecon. The design modifications discussed in the telecon were specific to the LPCI inverters. The Vital AC power function (R44-01) provides power for critical instrumentation loads during power operation which require a highly reliable source, but Vital AC is not safety-related, its failure does not prevent a safety function, and it is not required to operate during regulated events. Therefore, as seen in Table 2.2-1 of the application, this function does not meet the criteria for inclusion within license renewal scope as described by the Rule. Likewise, Vital AC room cooling is out of scope for license renewal.

The control building heating coils are electric. Thus, they were considered to be active components and were screened out and not included in Table 2.3.4-20 of the application. The duct heater frame was evaluated in the LRA (see table 2.3.4-20).

Open Item 2.3.4.2-1

With respect to the radwaste building, the staff reviewed the Plant Hatch FHA dated July 22, 1986 and concludes that fire suppression for certain areas in the radwaste building were included in the 1986 FHA. Specifically, Section IV.B.4.d of the FHA states that "fixed automatic water spray systems are installed in all charcoal filters in the plant". The radwaste building contains charcoal filters which are protected by fixed sprinkler systems. Therefore, the fire suppression piping leading to the charcoal filters, including the nozzles and sprinkler heads, should be included within the scope of license renewal and subject to an AMR.

In addition, Section IV.D of the FHA states that the guidelines for specific plant areas is presented for each specific plant area throughout the FHA. In both the 6/86 and 7/87 revisions to the FHA, the FHA analysis of fire area/zone 2301 (Radwaste Building - All Elevations) states that , "all sections of this area which contain specific fire hazards (charcoal filters) or high concentrations of combustibles (dry waste storage area, Radwaste Control Room) are equipped with detection, suppression, or both." Specifically, the west central portion of fire zone 2301J over the drywaste storage section is equipped with a wet pipe suppression system. To the staff's knowledge, the applicant has not submitted any information to the staff to show that the radwaste suppression system has been physically removed or altered so that it can't perform it's intended function and that no plant evaluations through 50.59 have determined that this suppression system is no longer required for compliance with Appendix A to BTP 9.5-1.

Therefore, it is the staff's view that the radwaste suppression system should be included within the scope of license renewal and subject to an AMR.

Response to Open Item 2.3.4.2-1:

Radwaste building fixed fire suppression has been included in scope for license renewal. No new component types, component materials, or internal or external environments result from this scope change. The existing three and six-column tables in the LRA identify the components and the applicable aging effects and aging management programs. The following evaluation boundary drawings were revised or created to reflect the change in scope:

HL-11034	HL-11901
HL-11304 Sheet 7	HL-11905
HL-11304 Sheet 8	HL-11909
HL-11869	HL-21017
HL-11873	HL-21197
HL-11874	HL-21342
HL-11875	HL-26372

Each above listed boundary drawing has been provided separately, in Adobe Acrobat (pdf) format by electronic communication.

Open Item 3.0-1

The content of the FSAR supplement is dependent upon the final bases for the staff's safety evaluation, as will be reflected in a subsequent revision to this report. Therefore, the resolution of the information that needs to be added to the FSAR supplement will be addressed after the other open items are resolved, prior to the issuance of the renewed license.

Response to Open Item 3.0-1

SNC's proposed FSAR supplement is provided as Enclosure 2. Information in the FSAR supplement is based on the current resolution of the NRC open items.

Open Item 3.1.1-1

The applicant's reactor water chemistry control program is based on the guidance provided in EPRI TR-103515, "BWR Water Chemistry Guidelines." In the staff's RAIs regarding any program elements that deviate from the referenced EPRI guidelines, the applicant indicated that the subject program implemented at Hatch complies with EPRI TR-103515, Revision 2.

The staff notes that EPRI TR-103515, Revision 2, has not been approved by NRC for generic use. Therefore, the applicant's reactor water chemistry control program should follow EPRI TR-103515, Revision 1, at this time. This is Open Item 3.1.1-1.

Response to Open Item 3.1.1-1

SNC indicated in the response to RAI 3.1.1-2 that Plant Hatch is committed to meeting the chemistry control parameters specified for RCS chemistry contained in EPRI TR-103515. As a point of information, SNC identified the applicable revision of that document which was current at the time the LRA was submitted, and further noted in the RAI response that SNC was updating the program to the later revision of the EPRI document. SNC believes it is important to maintain the flexibilty to modify plant chemistry control procedures based on the best industry guidance developed from the collective operating experience of similar reactors. Thus, over time, SNC expects to continue to revise the plant chemistry procedures to reflect changes in industry guidance as reflected in the EPRI control parameters. Thus, SNC does not believe it is appropriate to reference a specific revision of the guidance document.

The changes in the EPRI document from Revision 1 to Revision 2 illustrate this point. For reactor coolant, only two differences of any significance exist between Revision 1 and Revision 2 of the EPRI guidelines:

The first relates to the additional consideration of the beneficial effects of operation with HWC or HWC with NMCA. Revision 2 of the EPRI guidelines provides an additional table (4-5b) which allows relaxation of the power operation AL3 values for chlorides and sulfates from 100 ppb to 200 ppb when HWC is in service and measured ECP values are less than –230 mV (SHE). Currently, Plant Hatch operates in accordance with Revision 2 of the EPRI guidelines and the current sampling and monitoring procedure allows for higher AL3 chloride and sulfate values under HWC. This additional flexibility is warranted based on the increased protection of reactor coolant system and reactor assembly components provided by HWC or HWC with NMCA and that strict adherence to EPRI guideline values are not always the best course of action.

In addition, Revision 2 of the guidelines allows for monitoring of chlorides and sulfates on less than a daily basis, if appropriate based on site specific resource allocation needs.

Open Item 3.1.3-1

The diesel fuel oil testing program, like the various chemistry control programs in effect at Plant Hatch, is a mitigative activity which is not intended to directly detect age-related degradation. The implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program. Steel storage tanks are susceptible to corrosion from the outside by contact with the earth unless an effective cathodic protection system is employed. The applicant does not take credit for such a system. Also, water in the fuel oil will be in contact with the tank bottom, possibly causing corrosion. The diesel fuel oil testing program will not be able to detect such degradation. Therefore, the staff concludes that a one-time inspection program is warranted for the diesel fuel oil tanks to verify tank bottom thickness. The addition of a one-time inspection program for the tanks would be consistent with the applicant's approach for other chemistry control programs at Plant Hatch. For example, the torus submerged components inspection program complements the applicant's suppression pool chemistry control. Also, the condensate storage tank inspection complements the applicant's demineralized water and condensate storage tank chemistry control program. The staff requests the applicant provide specific attributes of an inspection program, consistent with other one-time inspections (e.g., inspection scope, inspection technique, acceptance criteria, etc.).

Response to Open Item 3.1.3-1

Since the license renewal application was submitted, SNC has inspected one of our buried, 40,000 gallon emergency diesel generator (EDG) fuel oil storage tanks (FOST). When Tank 1A was drained for cleaning last outage, SNC took advantage of that opportunity to conduct aging inspections. Based upon the excellent results obtained through visual examination and ultrasonic testing (UT), SNC has confidence that significant wall thinning has not occurred in the Plant Hatch EDG FOSTs and, therefore, the conclusion in the LRA that no aging management activites are required is substantiated.

The Plant Hatch EDG FOSTs are constructed of 0.5 inch plate steel. Ultrasonic testing, covering 144 points along the lower portions of the tank, indicated that wall thickness was consistently between 0.500 and 0.524 inches. In no case was a reading taken less than 0.5 inches. SNC believes that these results are representative of the other four tanks, since they are all the same material and they all have the same internal and external environments.

Prior to performing the UT, visual inspections were conducted of the "as-found" conditions. Very little corrosion was noted in the tank airspace. A thin adherent layer of general corrosion was identified in a small area. That small amount of surface corrosion was removed during cleaning.

In addition to the EDG FOSTs, the fire pump diesel fuel oil storage tanks are also in scope for license renewal. The internal environment of these smaller tanks is similar to the internal environment of the EDG FOSTs, each tank having a diesel fuel oil volume and an air vapor space. However, the fire pump diesel fuel oil storage tanks are not buried. They are above ground and are painted. Thus, the external environment is at least as benign as the external environment for the buried EDG FOSTs.

In summary, the FOST visual and UT inspection results already obtained are responsive to the issue raised in the open item and substantiate the LRA conclusion that loss of material is not an aging effect requiring management during the renewal term for either the EDG FOSTs or the fire pump diesel fuel oil storage tanks.

Open Item 3.1.11-1

The application stated that the plant commodity group in the scope for this activity is class 1 pressure boundary bolting and non-class 1 pressure boundary bolting. Class 1 pressure boundary bolting is fabricated from low alloy steel. The non-class 1 pressure boundary bolting is fabricated to the requirements of ASTM A-307 (Grade B), ASME SA-194 (Grade 2H), and ASME SA-193 (Grade B7). Bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. In response to RAI 3.4-1, the applicant did not state if the yield strength for ASME SA-193 (Grade B7) or any other bolts are limited to less than 150 ksi to avoid the possibility of stress corrosion cracking. See RICSIL No. 055, February 1, 1991, "RPV Head Stud Cracking." The staff requests the applicant to provide this information.

Response to Open Item 3.1.11-1

SNC agrees that bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. The materials used in bolting and threaded connections within the scope of license renewal are primarily carbon steel, low-alloy steels, and stainless steel. The bolting discussed by this open item was procured with a specified minimum yield strength of 105 ksi. An upper limit was not specified. LRA appendix C.2.2.10 identified the aging effects requiring management based on the material of the bolting without segregating high strength bolting, taking into consideration the plant operating history. SNC agrees that cracking is an aging effect that could be caused by stress corrosion cracking in bolting material subject to water or steam (e.g., from leakage) that contains various contaminants. Cracking of non-Class 1 bolting in an air environment has not been observed at Plant Hatch and was not identified in a survey of industry experience. Therefore, for Plant Hatch, cracking of non-Class 1 bolting in an air environment is not an applicable aging effect.

Open Item 3.1.13-1 (a)

In Section C.2.4.3 of the LRA, the applicant credits the PSW and RHRSW inspection program with managing the aging effects of RHR and PSW components exposed to a buried environment. The inspection program includes provisions for cleaning, priming, coating, and wrapping underground pipelines whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping. However, this aspect of the program is not discussed in Sections A.1.13 or B.1.13 of the LRA. The staff requests the applicant enhance its description of the PSW and RHRSW inspection program to clearly state that the scope of the program includes this particular aspect for managing aging effects associated with a buried environment, consistent with the discussion in Section C.2.4.3 of the LRA.

Response to Open Item 3.1.13-1 (a):

The PSW and RHRSW inspection program does not directly include provisions for cleaning, priming, coating, and wrapping underground pipelines. The protective coatings program addresses these activities. However, the site procedure for buried pipeline coating maintenance and installation does specifically invoke PSW and RHRSW inspection program inspection requirements whenever maintenance is performed on components in those systems. Therefore, the PSW and RHRSW inspection program and the protective coatings program are linked for buried pipelines.

The context of the open item indicates that some confusion may exist regarding the SNC approach toward aging management of externally initiated degradation of buried commodities within the scope of license renewal for Plant Hatch. The following discussion clarifies and consolidates SNC's approach to aging management of buried commodities.

SNC's aging management program approach for buried commodities having aging effects requiring management centers around inspection of the applied coal tar enamel coatings, and if coating degradation has occurred, inspection of the underlying base metal. The protective coatings program contains the technical requirements to ensure that piping coatings were adequately installed and maintained. These inspections are performed only when a commodity is made accessible by excavation activities. In addition, pressure testing activities and the associated VT-2 inspections required by the ASME B&PV Code, Section XI, Table IWC-2500 are credited to identify leakage in service water and RHR service water system buried commodities.

Initially, SNC had planned to include a "trigger" in the PCIA to initiate inspections per the PSW and RHRSW inspection program and the protective coatings program. On review, SNC concludes that this process resulted in significant confusion regarding the scope of credited aging management programs and activities. SNC further concluded that consolidation of the requirements for aging management of buried components will reduce confusion and increase confidence that inspections are properly initiated and performed by qualified personnel.

Since the buried commodities having aging effects requiring management utilize coal tar enamel coatings to prevent metal degradation, protective coatings personnel are the most qualified to perform these inspections, disposition the results, and provide for adequate maintenance and repair of the coatings. Toward this objective, the PCIA and the PSW and RHRSW inspection program have been removed from LRA section C.2.4.3, and the Appendix B program description for the PCIA has been modified to remove information related to the external surfaces of buried commodities. The "trigger" to assure that buried commodities are examined by protective coatings personnel will be placed in the site procedure used to manage excavation activities. Thus, when excavation is to occur, the "trigger" will be invoked to initiate the inspection activities in the protective coatings program.

For review efficiency, Table 1 provides information specifically focused on the external surfaces of buried commodities. No environment column is provided since all commodities have the same environment (buried). A system column has been added to ensure that no confusion exists regarding system applicability. In addition, a revised LRA section C.2.4.3 follows this response. This revised section includes not only the AMP consolidation change, but also corrections to the technical content identified subsequent to LRA submittal.

TABLE 1

Aging Effects Requiring Management for the External Surfaces of Buried Commodities at Plant Hatch

System	Description	Component Function	Material	Aging Effects Requiring Management	Aging Management Program / Activity
E11	RHRSW piping segments from the Intake Structure to Reactor Building. Piping is buried in a controlled backfill.	Pressure Boundary	Carbon Steel With Coal Tar Enamel Coating	Loss of Material	ISI Program (VT-2) Protective Coatings Program
E41	HPCI supply piping from the CST to the Reactor Building. Piping is buried in a controlled backfill or embedded in concrete.	Pressure Boundary Fission Product Barrier	Stainless Steel	None	N/A
E51	HPCI supply piping from the CST to the Reactor Building. Piping is buried in a controlled backfill or embedded in concrete.	Pressure Boundary Fission Product Barrier	Stainless Steel	None	N/A
P41	PSW Piping from the Intake Structure to the Reactor Building. Piping is buried in a controlled backfill.	Pressure Boundary	Carbon Steel With Coal Tar Enamel Coating	Loss of Material	ISI Program (VT-2) Protective Coatings Program
T46	SGTS piping from the Reactor Building to the Main Stack.	Pressure Boundary Fission Product Barrier	Carbon Steel With Coal Tar Enamel Coating	Loss of Material	Protective Coatings Program
Y52	EDG fuel oil supply piping from the buried storage tanks to the EDG Building.	Pressure Boundary	Carbon Steel With Coal Tar Enamel Coating	Loss of Material	Protective Coatings Program
X43	Fire protection header loop piping.	Pressure Boundary	Cast Iron	None	N/A

NOTE: Information presented in the above table applies to the exterior surfaces of buried commodities within the scope of license renewal at Plant Hatch only.

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 in scope 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)
- X43 – Fire Protection

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:

- *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, inspected and maintained. 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, 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.

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. Pressure testing is performed in accordance with ASME Code, Section XI, Table IWC-2500.

Review of Operating Experience

A review of the condition reporting database mentioned in section 3.0 did not identify any deficiencies related to corrosion of component exteriors for buried piping segments. Prior to the five year period for which condition reports were reviewed, failures of buried carbon steel RHRSW piping near the intake structure did occur. External corrosion was identified in areas where the coal tar enamel coating was field applied during the installation process and gaps in the coating were noted. At Plant Hatch, no failures have been identified where the coating had been properly installed.

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 ISI Program, 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 and the Protective Coatings Program provide for periodic inspections.
4.	The method of detection of the aging effects is described and performed in a timely manner.	The Protective Coatings Program provides 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 Protective Coatings Program and ISI Program provide trending of data to ensure proper corrective actions.
6.	Acceptance criteria are included.	The 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, 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.

Open Item 3.1.13-1 (b)

In Table 3.2.3-2 of the LRA, the RHR heat exchanger augmented inspection and testing program is credited with managing, in part, aging effects for various heat exchanger components, including the tubes, tubesheet, and shell. However, the description of the PSW and RHRSW inspection program contained in Section B.1.13 of the LRA includes several references to inspections of heat exchanger components. The staff requests that the applicant clarify the scope of the PSW and RHRSW inspection program relative to managing aging effects for the various heat exchanger components listed in Table 3.2.3-2 of the LRA.

Response to Open Item 3.1.13-1 (b)

The references to heat exchanger inspections in Appendix B, section B.1.13 are intended to describe the limited linkage between the RHR heat exchanger augmented inspection and testing program and the PSW and RHRSW inspection program. Refer to section C.2.2.11 of the LRA where the relationship is summarized. In this LRA section, the PSW and RHRSW inspection program is described as specifying visual inspection requirements that support RHR heat exchanger augmented inspection and testing program activities. The PSW and RHRSW inspection program is shown as a bulleted item under the RHR heat exchanger augmented inspection and testing program, and is not shown as a principal program in the list of the programs required to manage aging effects on page C.2-136 of the LRA.

Specifically, the PSW and RHRSW inspection program visual inspection methodologies and acceptance criteria for service water components were referenced by the RHR heat exchanger inspection and testing program, instead of duplicating similar information in more than one procedure. Therefore, this linkage is limited to inspection details, and as such, heat exchanger inspections should not be characterized as a significant attribute of the PSW and RHRSW inspection program.

In the subsequent implementation process, SNC determined that the program level procedure developed to implement the RHR heat exchanger augmented inspection and testing program at Plant Hatch should contain all the inspection methodologies and acceptance criteria applicable to RHR heat exchangers in one procedure. As shown during the March 2001 NRC AMP implementation inspection at Plant Hatch, this procedure reproduces visual inspection information from the PSW and RHRSW inspection program procedures and tailors this information for RHR heat exchanger visual inspections. A proposed implementing procedure which includes specific inspection methodologies and acceptance criteria for the RHR heat exchangers has also been developed. This procedure was reviewed in detail by the NRC during the site inspection conducted in March 2001.

Open Item 3.1.13-1 (c)

The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with Division I PSW piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and AMPs are consistent with other piping sections in this system. However, the length of the PSW piping surrounded by the guard pipe is sealed, that is, the plate is welded to the PSW pipe and to the guard pipe at both ends. Thus, the external surface of this section of PSW piping is not accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The staff requests the applicant to provide appropriate information about this one-time inspection, or a comparable engineering evaluation, prior to the end of the current term.

Response to Open Item 3.1.13-1 (c)

As stated in the open item, SNC plans to inspect a section of the PSW guard pipe. The guard pipe in question surrounds PSW process piping that carries water for EDG cooling. The inspection is planned in order to validate the external environment of that section of PSW piping, as well as to assess the external surface condition of the PSW piping inside the guard pipe.

Plant Hatch Engineering Support is responsible for determining a suitable method, or methods, and for conducting an inspection. SNC plans to conduct the inspection concurrent with the 1B EDG outage scheduled for February 2002.

Current plans are to cut a window in the guard pipe so that visual, boroscope or other suitable examination method may be used to determine the condition of the exterior surface of the PSW process pipe. One or more windows may be required, and different examination methods may be required in order to obtain adequate information regarding the exterior environment and material condition of the PSW piping. The results will be documented and evaluated, and additional actions will be taken if results warrant.

Open Item 3.1.17-1

In response to RAI 3.1.17-1, the applicant indicated that it plans to implement the provisions of an integrated surveillance program (ISP) that is documented in BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan." Should the ISP not be approved by the NRC, or if it should be modified such that Plant Hatch is not covered by the ISP, the applicant stated that it would develop an RPV surveillance program for the renewal period. In a telephone conference on November 3, 2000, the applicant reiterated that its expectation is that the ISP, or its implementation document, will address these attributes and that, if the staff rejects BWRVIP-78, or if BWRVIP-78 is modified to the extent that the applicant cannot apply it to Plant Hatch, the applicant will develop an RPV materials surveillance program for the renewal period. As part of this commitment, if the applicant participates in the ISP or implements a plant-specific reactor vessel surveillance program, the ISP or plant-specific program should address the 10 program attributes. If the program cannot meet any program attributes, the applicant should provide a technical justification for the discrepancies.

Response to Open Item 3.1.17-1

SNC is committed to implementing an ISP based on the technical criteria of BWRVIP-78. If the ISP is approved by NRC in a manner that includes Plant Hatch, the ISP will be implemented. If the ISP is not approved by NRC, or is modified such that Plant Hatch is not covered, SNC will develop and implement a plant-specific ISP. The plant-specific ISP, if one is needed, will be developed in a manner consistent with other aging management programs SNC developed, and will include consideration of the ten program attributes SNC has utilized for aging management and which are contained in the draft SRP-LR. We do note, however, that a plant-specific program, if needed, may not include all ten attributes. Other aging management programs in the Plant Hatch LRA may be credited for certain of the ten attributes. For example, the corrective actions program is broadly credited for satisfying attributes seven through ten. Should development of a plant-specific ISP be needed, SNC will include a technical justification for any program attribute not covered by a SNC-developed program when applied to managing the aging effects under consideration by the ISP.

Open Item 3.1.18-1 (a)

This open item was closed by NRC on its own initiative.

Open Item 3.1.18-1 (b)

With regard to the inspection frequency of fire system components, the applicant lists in Section B.2.1 of the LRA the different inspection intervals for the water-based fire protection systems, fire protection pump diesel fuel oil supply system, compressed gas based fire suppression systems, fire penetration seals, cable tray enclosures, and fire doors. In addition to the systems listed above, the applicant describes a one-time inspection called the "Sprinkler Head Inspections" that will be performed at or before the start of the extended period of operation for closed sprinkler heads within the scope of license renewal. In RAI 3.1.18-9, the staff requested that the applicant provide justification for the absence of enhanced inspection programs for the sprinkler heads, which do not have a design life that covers the period of extended operation. In response the applicant stated that, "in general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern," and that using the guidelines of the National Fire Protection Act (NFPA) Code 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection," a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads." The staff does not agree that a one-time inspection is sufficient for the sprinkler heads and recommends that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, Section 2.3.3.1, "Sprinklers." Section 2.3.3.1 states that "where sprinklers have been in place for 50 years, they shall be replaced, or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing. In addition, the staff has notified the nuclear industry, through recent information notices, about the potential failures associated with sprinkler heads. These information notices include IN 99-03, "Potential for Failure of the 'Model GB' Series Sprinkler Heads with 'O-Ring' Water Seals;" IN 99-28, "Recall of Star Brand Fire Protection Sprinkler Heads;" and IN 97-72, "Potential for Failure of the Omega Series Sprinkler Heads." Problems with seals leaking and sprinkler heads failing to actuate are typically not detectable through the performance of existing visual inspections. Therefore, the staff requests that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, or provide additional justification for the applicant's proposed inspection interval.

Response to Open Item 3.1.18-1 (b)

SNC has previously addressed this issue in its responses to RAIs 2.3.4-FPS-10 and 3.1.18-9. SNC supplements those responses by expanding the scope of the inspection referenced in the response to RAI 3.1.18-9 to include the 10-year inspection interval recommended in NFPA-25 for closed-head sprinklers. Thus, the revised commitment is to use the guidance of NFPA-25 to perform an inspection of closed-head sprinklers after 50 years of service and at 10-year intervals thereafter. A revised Appendix B section 2.1 is provided as a part of Enclosure 3.

Open Item 3.1.28-1

The staff is concerned about vibration-induced cracking in the RHR heat exchangers. The RHR heat exchanger augmented inspection and testing program description is unclear regarding its ability to manage vibration-induced cracking. Therefore, in order to ascertain whether this AMP is adequate to manage vibration-induced cracking, the staff requests that the applicant provide additional information. The requested information is summarized below.

(a) The applicant should provide information on the inspection methods, frequencies, acceptance criteria, and associated bases which are used to detect vibration-induced cracking.

Response to Open Item 3.1.28-1 (a):

Currently, there is no site or industry operating experience indicating that vibration induced fatigue cracking is an active mechanism in RHR heat exchangers. This conclusion is based on updated inspection results and additional evaluation. However, the RHR heat exchanger augmented inspection and testing program provides for inspection activities that are capable of detecting significant tube damage or through wall leakage that could result from postulated vibration induced damage.

LRA section C.1.2.4 indicates that the heat exchanger tubes and tubesheet are theoretically more susceptible to vibration damage than other heat exchanger components. Therefore, this response focuses on the tubes and tube-tubesheet interfaces.

Eddy current testing is performed, as a minimum, once during each 10 year inspection period for each heat exchanger. Testing may also be conducted when tube leaks are suspected. Each heat exchanger inspection involves examination of a minimum of 10 percent of the operational tubes. Increased inspection sample sizes and frequencies may be utilized where results of past inspections warrant additional surveillance.

Testing is performed by qualified personnel with extensive experience and includes the accessible portions of the straight tube sections and U-bends. Inspection results provide information related to overall condition of the tubes, suitability for continued operation, recommended corrective actions, and trending of results from past inspection activities.

Eddy current test results that indicate significant tube damage are evaluated by qualified eddy current evaluation personnel and engineering support personnel. Based on the judgement of the engineering support personnel, tube damage that may result in tube leakage prior to the next inspection period requires corrective action. Appropriate corrective actions may include additional examinations, tube plugging, or increased surveillance.

Leak testing may be utilized to identify leaks in heat exchanger tubes or tubesheets. Testing is performed only when a leak is suspected through a heat exchanger tube or tubesheet. Therefore, no set frequency exists for leak testing activities. The intent of leak testing is to locate a leak, not to quantify a leak. Any leakage identified during leak testing is unacceptable.

The RHR heat exchanger augmented inspection and testing program requires that general visual examinations of the "as found" tubesheet and tube bundle surfaces be periodically performed from both the channel side and shell side of the heat exchanger. Channel side inspections will be performed every three operating cycles for visible portions of the tubesheet and tubes. Shell side inspections will be performed once during each ten year interval and include a representative portion of the tube bundle, tube supports, tube to tubesheet interface, and baffles. Any crack-like or linear indication identified during visual inspections will be considered significant by inspection personnel and subject to additional engineering evaluation.

Eddy current examination, leakage testing, and visual inspection methodologies, frequencies, and acceptance criteria are based on site operating experience and available industry information related to heat exchanger failures. A review of industry experience, including LERs, INPO NPRDS records, NRC bulletins, Information Notices, Generic Letters, and Circulars, presented in DOE report SAND 93-7070 indicates that failures of RHR system heat exchangers will most likely be due to fouling or corrosion, not vibration induced damage.

Open Item 3.1.28-1 (b)

The applicant should provide information regarding the leakage identified in 1996, including the analyses conducted that determined the cause of the leakage, the operational changes or component modifications that were instituted in response to the leakage, and additional programs which were credited for managing vibration-induced cracking.

Response to Open Item 3.1.28-1 (b):

The following chronology describes actions related to potential leakage in one Unit 1 RHR heat exchanger:

1996:
Tube leakage was suspected in a Unit 1 RHR heat exchanger due to the detection of radionuclides in the RHRSW system.

October 1997:
The tube bundle was inspected utilizing both leak testing and eddy current testing methods. Leakage testing identified leakage in one tube only. Eddy current testing identified a total of nine tubes, including the leaking tube, with significant damage (including dents at some tube to tube support intersections). All of these tubes were located in the same region of the tube bundle and were plugged based on the recommendations of inspection personnel. No direct evidence of any service induced damage mechanism was identified by this inspection and the cause of the leaking tube could not be clearly established. A follow up inspection was recommended.

October 2000:
A subsequent eddy current examination of all heat exchanger tubes, except those plugged after the October 1997 inspection, did not reveal any accelerated degradation indicators or adverse trends, and concluded that no evidence of any active service induced degradation mechanisms exists. The overall tube bundle condition was determined to be good and suitable for continued service. Inspection personnel postulated that existing tube defects may be due to mill flaws or damage sustained during bundle assembly or installation and are unlikely to propagate during continued service.

Open Item 3.1.28-1 (c)

The LRA states that measured and recordable values of the inspected or monitored parameters shall not fall below acceptable values for defined inspection locations. The staff requests that the applicant identify the inspection locations, and the inspection criteria used to determine inspection locations, and their bases.

Response to Open Item 3.1.28-1 (c):

General visual inspections will emphasize those locations more likely to exhibit excessive fouling or localized corrosion such as tubes, tube to tubesheet interfaces, gasketed surfaces, creviced areas, and welds. Specifically, channel side inspections include all areas visible with the channel cover removed and focus on visible portions of tube interior surfaces, tube-tubesheet interface areas, partition plate and channel cover gasket surfaces, and all welds. Shell side inspections are conducted utilizing remote inspection equipment and include only a representative area since the shell side is exposed to relatively clean torus water and not river water. Shell side inspections focus on tube to tubesheet interfaces, tube to baffle interfaces, tube to tube support interfaces, tie rods or fasteners, and accessible welds. Any indications of cracking or excessive corrosion or erosion will be identified by the inspection personnel and are subject to an engineering evaluation.

Eddy current testing is generally conducted on a minimum of 10 percent of operational tubes in the tube bundle. Testing is performed on both the straight tube and U-bend sections. Any areas unavailable for inspection due to the inability to pass an eddy current probe are noted on the inspection report. Based on the judgement of the responsible engineer, tube damage that may result in tube leakage prior to the next inspection period requires corrective action.

Leak testing of heat exchanger tubes is performed to locate a leak. Therefore, the entire tube is tested. Leak testing is performed whenever a leak is suspected in the tubes or tube sheet. No leakage is allowed.

Open Item 3.1.28-1 (d)

The LRA states that a sample taken from an RHRSW drain valve contained the nuclides and, as a result, testing was performed on one of the Unit 1 RHR heat exchangers. Dents were found at a number of tube-to-tube support connections and the dents may indicate tube vibration. The staff requests the applicant to provide the basis for its determination that the dents may have been caused by tube vibration, as opposed to localized corrosion. In addition, the staff requests that the applicant provide information regarding industry experience related to the bases and criteria of the inspections credited in the RHR heat exchanger augmented inspection and testing program.

Response to Open Item 3.1.28-1 (d):

Denting, as referred to in the submitted operating history on the 1E11-B001B RHR heat exchanger, is simply indicative of heat exchanger tube roundness. Eddy current testing is conducted using a probe that is as close as possible to the ID of the tube to be inspected. In other words, denting that is not severe enough to block the probe is not a major concern, so long as the damage is not progressing. Dents can be service induced, but many times are fabrication flaws from either tube bending or insertion. Inspections performed during the fall 2000 outage indicated the damage is not active and is limited to specific areas of the tube bundle. Therefore, based on the fall 2000 inspection results, no evidence exists to support localized corrosion or vibration as a significant factor in the tube dents identified.

A review of recent site operating experience does not indicate any significant problems regarding RHR heat exchanger operation other than the information presented in response to part (b) of this open item. While degradation has been identified, no evidence of accelerated degradation that would result in failures between inspection intervals has been observed. A review of industry information presented in DOE report SAND 93-7070 supports this conclusion in that the majority of RHR system heat exchanger failures are due to progressive mechanisms such as fouling or erosion.

Therefore, based on inspection results obtained to date, and reviews of available industry information, SNC maintains that periodic inspection activities are adequate to detect degradation prior to loss of intended function.

Open Item 3.2.3.1.1-1

The BWRVIP for the jet pump assembly components is described in EPRI TR-108728, "BWRVIP BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (BWRVIP-41)." The staff-approved BWRVIP-41 does not recommend an inspection of CASS jet pump assembly components because CASS components are considered not susceptible to IGSCC and the neutron fluence in the annulus region is not large enough to cause irradiation embrittlement. However, BWRVIP-41 does not contain any data to indicate the threshold for neutron embrittlement of CASS and does not identify the neutron fluence of the CASS jet pump assembly components. Because BWRVIP-41 does not provide data to support its conclusion that inspection of CASS components is not needed, the staff cannot conclude that the loss of fracture toughness resulting from irradiation embrittlement and cracking is not a plausible aging effect requiring aging management. The staff notes that irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Therefore, if the applicant can show that cracks do not occur in the CASS components, then the staff can conclude that loss of fracture toughness resulting from neutron irradiation embrittlement will not be a significant aging effect.

Industry-wide experience shows that significant cracking has not been observed in CASS jet pump assembly components. To confirm that CASS components are not susceptible to cracking, the applicant should propose an AMP (one-time inspection) for the CASS jet pump assembly components and fuel supports, which will be conducted prior to beginning the extended operating period. The BWRVIP and the NRC's Office of Regulatory Research (RES) is engaged in a joint confirmatory research program to determine the effects of high levels of neutron fluence on BWR internals, including associated age-related degradation, to confirm if CASS components are susceptible to cracking as a result of neutron embrittlement. The results of this program should be used to evaluate the need for the additional one-time inspection of the CASS jet pump assemblies and fuel supports, and to modify the inspection scope and/or frequency, as needed. The applicant should address the 10 AMP attributes in its description of the inspection, including any corrective actions to be taken (including repair and replacement) if cracking is discovered.

Response to Open Item 3.2.3.1.1-1

As noted in the Hatch LRA, Hatch is committed to implementing the BWRVIP documents listed in the application. BWRVIP-41 is one of those documents. We will continue to participate in the BWRVIP activities. If the criteria in BWRVIP-41 are revised, we will follow them or notify the NRC of the alternate actions we plan to take. Further, as noted in our response to the RAI, the jet pump assemblies will not exceed the 550 degree F threshold the NRC has defined as the point at which thermal aging of CASS occurs. Therefore, this is not an aging concern for Plant Hatch.

Open Item 3.2.3.2.3-1

The staff is concerned that unanticipated high cycle thermal fatigue resulting from thermal stratification or turbulent penetration could result in cracking of small bore piping. This type of cracking is not evaluated as part of the component cyclic or transient limit program. The ASME Code Class 1 inspection requirements for small-bore piping include a surface examination, but not a volumetric examination. In order to detect cracking resulting from high cycle thermal fatigue, a volumetric examination is required. Since the proposed program does not include a volumetric examination, it may not be capable of detecting high cycle thermal fatigue cracks resulting from thermal stratification or turbulent penetration. Therefore, the applicant should supplement the existing programs with volumetric examination of the limiting locations in small-bore piping systems, excluding socket welds, which could have thermal stratification or turbulent penetration.

Response to Open Item 3.2.3.2.3-1

SNC has performed a review of the Class 1 piping drawings to assess the potential for thermal fatigue in small-bore piping. The review excluded those portions of piping that contained socket welds. As a result of this cursory evaluation that considered location, geometry, and normal operating conditions, SNC did not identify areas where thermal cycling due to turbulent eddy currents or thermal stratification would be expected.

As noted in its January 31, 2001 letter responding to various potential draft SER open items, SNC also reviewed the significance of cracking in small-bore piping and used that information as a screening tool to further assess the need for inspections or other aging management besides the existing ASME Section XI pressure testing requirements. That information is included in this response as well for completeness.

In addressing the significance of thermal fatigue cracking of Class 1 piping components as a result of thermal stratification or turbulent penetration, SNC maintains that the current open item issue is limited to ASME Class 1 pipe welds which meet two specific criteria. First, ASME Section XI, Table IWB-2500-1, based on pipe sizes less than NPS 4, requires only surface examination. Second, the pipe size is sufficiently large that a failure could result in a rate of coolant loss in excess of the capacity of makeup systems (as described in IWB-1220(a)). An analysis performed by GE in 1997 determined the line sizes which could be excluded from ISI Class 1 surface and volumetric examination based on makeup capacity to be as follows:

- Hatch Unit 1 2.5" diameter for water and 5.0" diameter for steam
- Hatch Unit 2 2.1" diameter for water and 4.2" diameter for steam

This analysis assumes that water lines are those which penetrate the RPV below normal water level and steam lines are those which penetrate the RPV above normal water level. Therefore, based on these values, water containing piping of NPS 2 and smaller and steam containing piping of NPS 4 and smaller are excluded from further consideration regarding the issue of thermal fatigue as presented in this open item.

Based on the above postulates, a review of HNP piping drawings reveals the following pipe segments that do not require volumetric examinations per IWB-2500, and are large enough that a failure could result in a rate of coolant loss in excess of available makeup capacity:

- H16188 – RWCU piping between check valve 1G31-F203 and the branch connection to the HPCI injection line. This is a short segment of NPS 3 piping containing three welds.

- H16188 – 3"x4" expander downstream of 1G31-F039 (check valve at RWCU discharge to the RCIC injection line. Only the weld at 1G31-G039 is less than NPS 4.

For these specific segments, a cursory evaluation of location, geometry, and normal operating conditions indicates that these piping segments are not in areas where thermal cycling due to turbulent eddy currents or thermal stratification would be expected. Additionally, these locations, with regard to turbulent penetration or thermal stratification, are likely bounded by volumetric examinations of other ASME Class 1 piping welds conducted under the requirements of other inspection activities such as ASME Section XI, Table IWB-2500-1 or NUREG 0619.

Therefore, SNC concludes that, based on volumetric examinations of bounding locations conducted by other programs, no action need be taken by Plant Hatch regarding this open item.

Open Item 3.6.3.1-1

In Section 2.4.6 of the LRA, the intended function of the reactor building penetrations (T54-01) is "maintain secondary containment leakage rates within design limits." In TS Section B 3.6.4.1, under "LCO," it states "For the secondary containment to be OPERABLE, it must have adequate leak tightness to ensure that the required vacuum ... can be established and maintained." Numerous penetrations associated with the reactor building could contribute towards violating the design limits established for secondary containment (i.e., reactor building). Thus the applicant should have an AMP to demonstrate that the overall effect of numerous degradations has not violated the leakage characteristics of the reactor building.

Response to Open Item 3.6.3.1-1

SNC has revised the structural monitoring program to include the provisions of Unit 1 and 2 Technical Specifications Surveillance Requirement SR 3.6.4.1.4. The flow test performed pursuant to the Surveillance Requirement will be credited for aging management as an additional detection measure that is capable of detecting gross changes in flow that may be indicative of aging degradation. A revised Appendix B section 2.5 is provided as a part of Enclosure 3.

Open Item 3.6.3.2-1 (a)

This open item was closed by NRC on its own initiative.

Open Item 3.6.3.2-1 (b)

This open item was closed by NRC on its own initiative.

Open Item 4.1.3-1 (a)

Table 4.1.1-1 of the LRA identifies piping stress analyses that consider thermal fatigue cycles as a TLAA. The table does not identify the fatigue analyses of other reactor coolant pressure boundary components or the reactor vessel internals as TLAAs. Section 4.2 of the LRA does address the reactor pressure vessel. In RAI 4.1-2 the staff asked the applicant to identify other components of the reactor coolant pressure boundary that have fatigue analyses. The staff also asked the applicant to describe the TLAAs performed to address fatigue for the reactor coolant pressure boundary components, except for the reactor vessel, that were not included in Table 4.1.1-1, and to describe the TLAA performed for the reactor vessel internals. The applicant was also asked to indicate how these TLAAs meet the requirements of 10 CFR 54.21(c). In response, the applicant stated that the criteria of BWRVIP-74 was used to determine which fatigue analyses were significant enough to be a TLAA. As indicated in the RAI, the applicant discussed the fatigue analysis of the reactor vessel internals in the FSAR. The staff requests that the applicant explain how the fatigue analysis of the vessel internals was found to be acceptable for the 60-year period. The staff also requests that the applicant identify any other components of the reactor coolant pressure boundary that had fatigue analyses and explain how these analyses were found acceptable for the 60-year period.

Response to Open Item 4.1.3-1 (a)

On May 3, 2001 NRC staff and SNC personnel discussed this open item via a telecon. On that call, NRC clarified the open item. NRC specifically asked about fatigue of RPV internals, noting a FSAR reference that contained a calculated jet pump assembly fatigue CUF of 0.65. NRC staff asked why fatigue of the jet pump assembly was not a TLAA.

In response to that question, SNC has reviewed the data used to disposition the FSAR calculated value. The initial Plant Hatch vessel internals AMR noted that cracking due to fatigue was an aging effect requiring management and that the calculation was a TLAA. The AMR specified inspection to manage the aging effect. Subsequent to development of the initial AMR, the end-of-life CUF was obtained. The end-of-life value obtained was substantially less than 0.5. Using the screening criteria of VIP-74, SNC then determined that the fatigue calculation results were not significant. On that basis, SNC concluded that the fatigue calculation did not represent a TLAA.

Based on the reexamination of the projected end-of-life CUF for the jet pump assembly, the fatigue at this location is bounded by locations included in the monitoring program.

Open Item 4.1.3-1 (b)

Section 4.2.2 of the LRA contains a discussion of the Plant Hatch licensing basis pipe break criteria. Part of the Plant Hatch pipe break criteria involves postulation of pipe breaks at locations where the calculated fatigue usage exceeds a specified value. Although the applicant identified the fatigue cumulative usage factor (CUF) calculation as a TLAA, the applicant concluded that the pipe break criteria was only a screening criteria and not a TLAA (the specific design criterion pertaining to the fatigue evaluation of RCS components involves calculating a quantity called the cumulative usage factor. The fatigue damage caused by each thermal or pressure transient depends on the magnitude of the stresses in the component caused by the transient. The CUF involves a summation of the fatigue usage resulting from each transient. The design criterion requires that the CUF not exceed 1). The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In RAI 4.2-1 the staff asked the applicant to provide a description of a TLAA for the pipe break criteria at Plant Hatch and to describe how the TLAA meets the requirements of 10 CFR 54.21(c). In response, the applicant stated that it views the pipe break criteria to be a selection criteria that establishes a bounding set of locations for line break consideration. Although the staff agrees with the applicant's statement, the staff still considers pipe break postulations a TLAA because the fatigue calculation is a TLAA. Additionally, the NRC previously identified high-energy line break postulation based on fatigue cumulative usage factor as a TLAA in accordance with 10 CFR 54.3 (60 FR 22480, May 8, 1995). Therefore, the staff requests that the applicant include pipe break postulations based on fatigue usage factor as a TLAA.

Response to Open Item 4.1.3-1 (b)

This open item was discussed in an open item resolution meeting with NRC staff on March 29, 2001. Based on the results of that meeting, the topic is a subject of a June 6 appeal meeting. Resolution of this issue will be documented following completion of the appeal process.

Open Item 4.2.3-1

By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two EPRI technical reports dealing with the fatigue issue. EPRI Reports TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," and TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations" were part of an industry attempt to resolve GSI-190. As recommended in SECY 95-245, EPRI analyzed components with high usage factors, using environmental fatigue data. The staff has open technical concerns regarding the EPRI reports. The staff technical concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998. NEI responded to the staff concerns in a letter dated April 8, 1999. The staff submitted its assessment of the response in an August 6, 1999, letter to NEI. As indicated in the staff letter, the NEI response did not resolve all staff technical concerns regarding the EPRI reports.

The applicant indicates that EPRI license renewal fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects for Plant Hatch. As discussed above, the staff does not agree with the contention that the EPRI fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects. Although the August 6, 1999, letter identified staff concerns regarding the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff has additional concerns regarding the applicability of the EPRI BWR studies to Plant Hatch. EPRI Report TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components," addressed a BWR-6 plant and EPRI Report TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant," used plant transient data from a newer vintage BWR-4 plant. In RAI 4.2-2, the staff requested that the applicant provide additional information regarding the use of the EPRI license renewal fatigue studies to resolve the environmental fatigue issue at Plant Hatch.

In response to the RAI, the applicant discussed its assessment of the impact the environmental correction factors for carbon and low-alloy steels contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and those for austenitic stainless steels contained in NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels" on the results of the EPRI studies. As a result of its assessment, the applicant concluded that the correlations have been adequately accounted for via the conservatism of the design basis transients.

The applicant indicated that EPRI Report TR-110356 contained studies that are directly applicable to Plant Hatch because the study involved a BWR-4 that is identical to the Plant Hatch design. The only components evaluated in TR-110356 are the feedwater nozzle and the control rod drive penetration locations. However, the applicant indicated that both Plant Hatch units employ hydrogen water chemistry, whereas the plant in the EPRI study did not consider hydrogen water chemistry. Hydrogen water chemistry affects the level of dissolved oxygen in the primary system. Dissolved oxygen is an important factor in the environmental fatigue effects. The applicant stated that this issue was adequately addressed by its evaluation of the feedwater nozzle contained in EPRI Report TR-105759. It is not clear to the staff how the issue of hydrogen water chemistry was addressed in EPRI Report TR-105759. The applicant's response has not resolved the staff concerns regarding the environmental fatigue issue at Plant Hatch.

The staff requested that the applicant provide an assessment of the six locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999, 'Interim Fatigue Curves to Selected Nuclear Power Plant Components'," March 1995, for an older vintage BWR (BWR-4) considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Plant Hatch Units 1 and 2. The applicant indicated that these locations are monitored by the CCTLP and that the environmental factors have been adequately accounted for by the conservatism in the design basis transient definitions. On the basis of the discussion above, the staff does not agree with the applicant that environmental fatigue concerns regarding the six locations identified in NUREG/CR-6260 have been adequately addressed at Plant Hatch. The applicant is therefore requested to assess these six locations, considering applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704, as applicable.

Response to Open Item 4.2.3-1

Table 3 of the response to RAI 4.2-2 presented an evaluation of the six locations identified in NUREG/CR-6260. Subsequent to that submittal, the MRP Fatigue ITG incorporated the Hatch response into the environmental fatigue report as an example of how to use the method of cycle counting. The MRP met with NRC on January 31, 2001 to discuss the MRP document. During the meeting, the Hatch method was discussed. NRC staff comments in that meeting focused on the applicability of the EPRI study to the BWR fleet. Thus, given that the response to RAI 4.2-2 has presented the results of the evaluation of the six locations identified in NUREG/CR-6260, and based on NRC staff observations regarding the Hatch method in the MRP meeting, SNC has prepared the following discussion to show how the EPRI study is applicable to Plant Hatch, validating the previously submitted assessment of the six locations. The validity of the EPRI study to Plant Hatch was also discussed in NRC/SNC telecons regarding the SNC response to the open item.

The (b) part of SNC's response to RAI 4.2-2 is replaced by this revised and expanded discussion which addresses the issues raised by Open Item 4.2.3-1.

Focusing on EPRI Report No. TR-110356, those results are considered directly applicable to Plant Hatch. First, the results documented in that report apply to a BWR-4, which is identical to the Plant Hatch design. Therefore, the Class 1 systems associated with the plants are the same, which defines the characteristics of the thermal transients in these systems. These similarities are most clearly observed in the plant heat balance diagrams and thermal cycle definitions. In particular, the thermal cycle definitions for the RPV nozzles provide a good measure of the thermal characteristic similarities between plants, because they represent fluid variations based on the combinations of several plant systems prior to entering the RPV. The heat balance diagram and several key thermal cycle diagrams for the generic BWR-4 evaluated in EPRI Report No. TR-110356 are provided in Attachment A. The similar diagrams for Plant Hatch are provided in

Attachment B [1]. Comparison of these diagrams allows the following conclusions to be made:

- The feedwater inlet temperatures are within 4% of each other (397.6°F for Plant Hatch vs. 383°F for generic BWR-4).
- The feedwater flow rate is approximately 15% higher for the generic BWR-4 plant compared to Plant Hatch (11.614 Mlb/hr for Plant Hatch vs. 13.574 Mlb/hr for generic BWR-4). Therefore, the stresses in the generic BWR-4 plant feedwater nozzle regions are conservative for use at Plant Hatch, since the higher flow rate will lead to higher stresses (due to increased heat transfer coefficients). A similar argument can be made for the steam and core flow rates.
- The recirculation inlet temperatures are within 1% of each other (532.1°F for Plant Hatch vs. 529°F for generic BWR-4).
- The recirculation flow rates are the same for both plants (34.20 Mlb/hr for both plants).
- The dome pressures are within 3% of each other (1,050 psig for Plant Hatch vs. 1,020 psig for generic BWR-4).
- All like transients have the same profiles (i.e., they have the same "size and shape").

Further similarities between Plant Hatch and the generic BWR-4 evaluated in EPRI Report No. TR-110356 are demonstrated in Table 2 of the response to RAI 4.2-2, where the design basis transient types and quantities for both plants are compared.

As a result of the above comparisons, the design basis transient definitions associated with the plants are very similar, as expected for similar BWR-type plants. Therefore, it is reasonable to utilize the results and conclusions documented in EPRI Report No. TR-110356 for Plant Hatch, with some modification to incorporate the results of more recent laboratory testing (as described above).

[1] Note that, in both of the attachments, there are some minor differences in temperatures, pressures, and flow rates between the heat balance diagrams and the thermal cycle definitions for each plant. These differences are associated with power uprate implementation at both plants, where the heat balance diagrams have been revised to reflect uprate conditions, but the thermal cycle diagrams have not. As a result of this, all comparisons were based on values identified on the heat balance diagrams.

Attachment A
Characteristic Thermal Definitions for Generic BWR-4 Evaluated in EPRI Report No. TR-110356

Figure A-1. Heat Balance Diagram

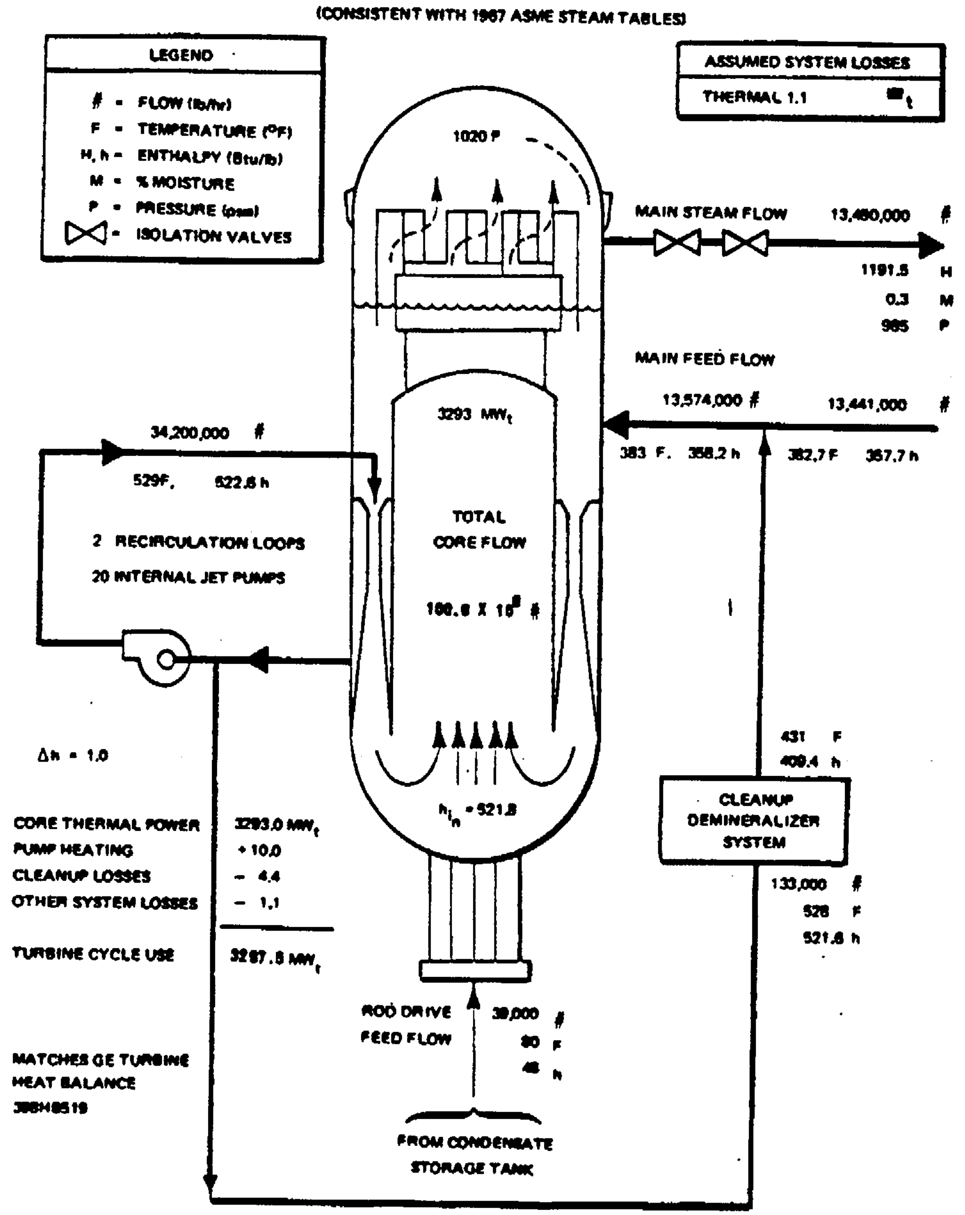
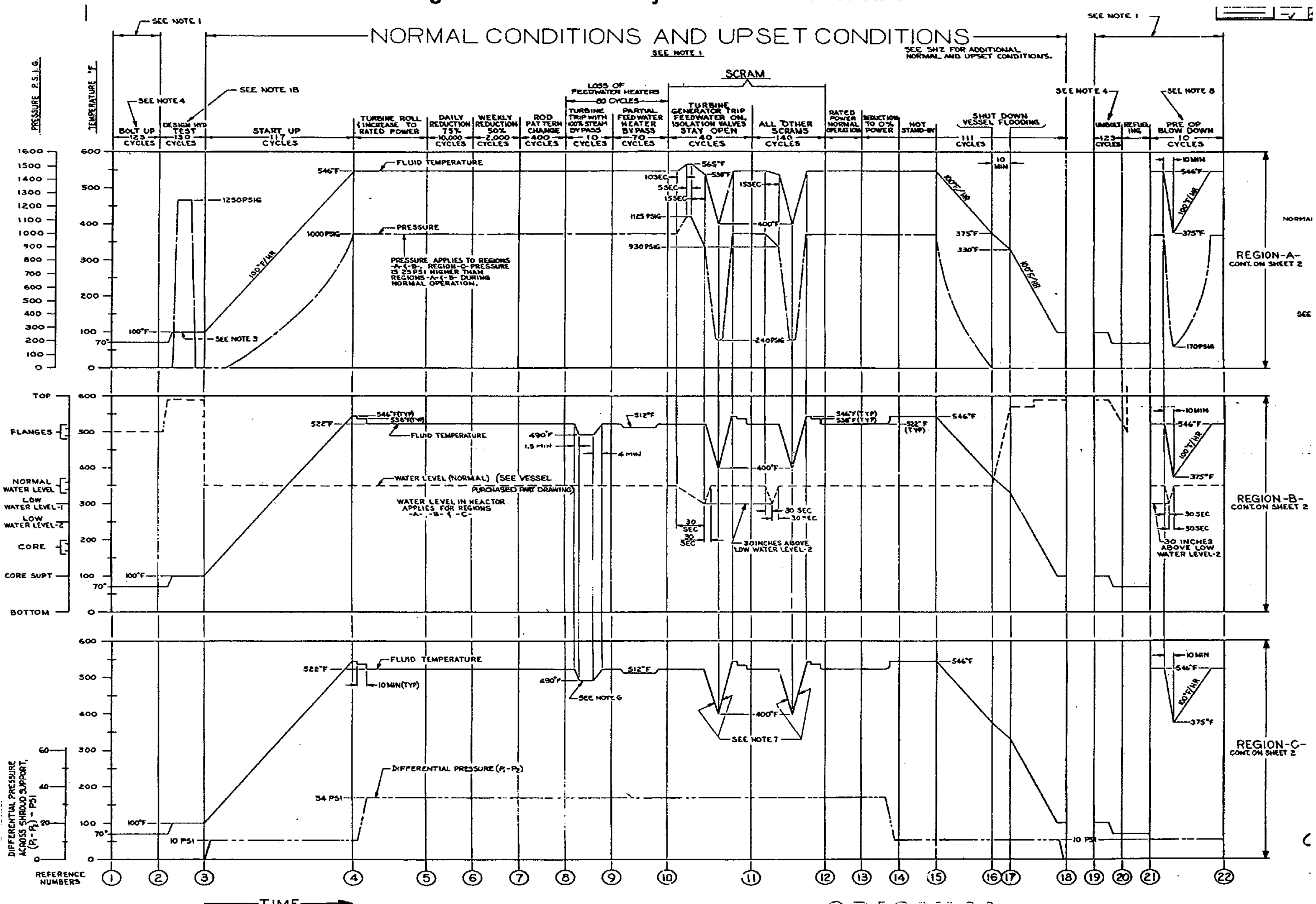


Figure A-2. Thermal Cycle Definitions for RPV



ORIGINAL

Figure A-3. Thermal Cycle Definitions for Recirculation Inlet Nozzle

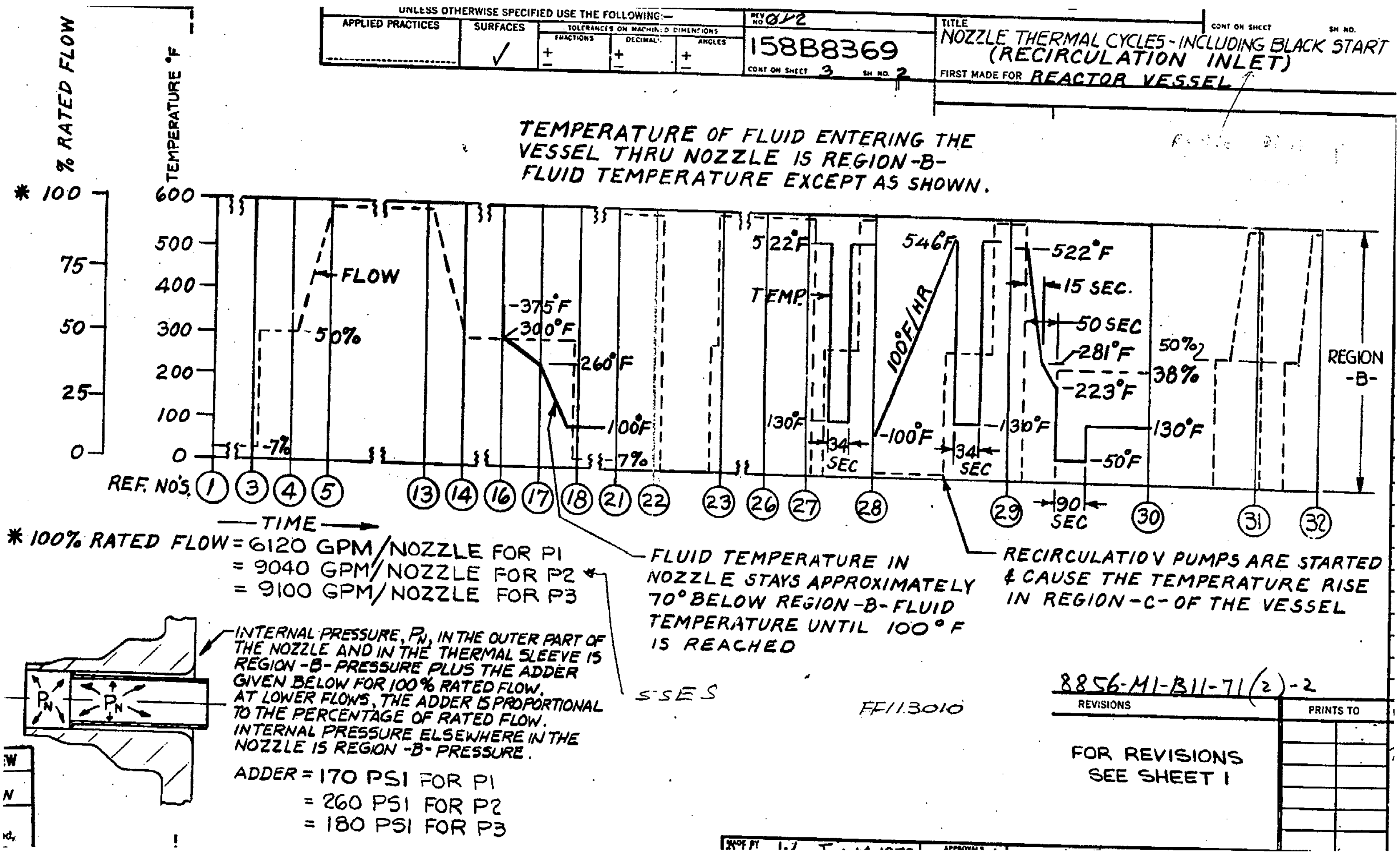


Figure A-4. Thermal Cycle Definitions for Recirculation Outlet Nozzle

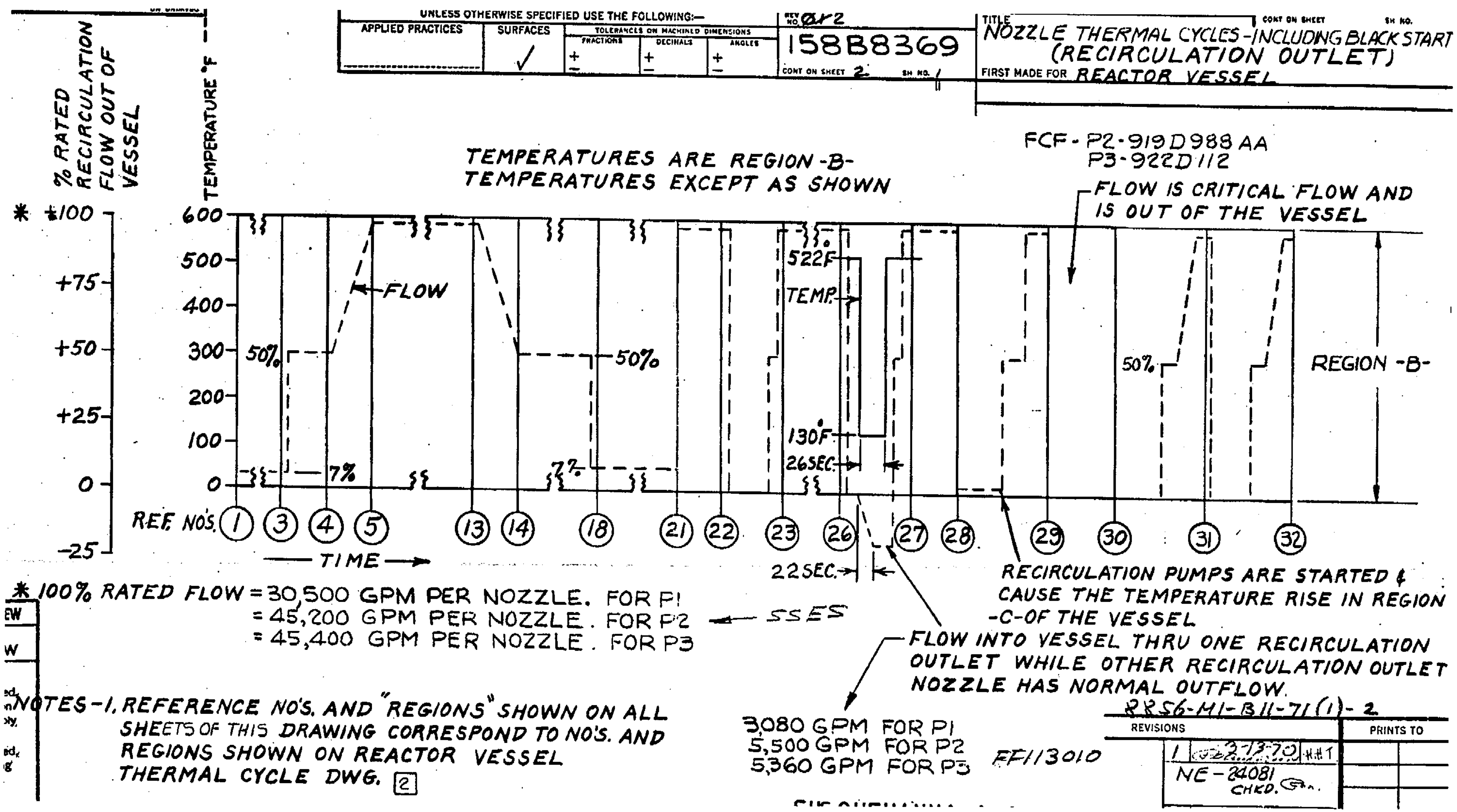


Figure A-5. Thermal Cycle Definitions for Feedwater Nozzle

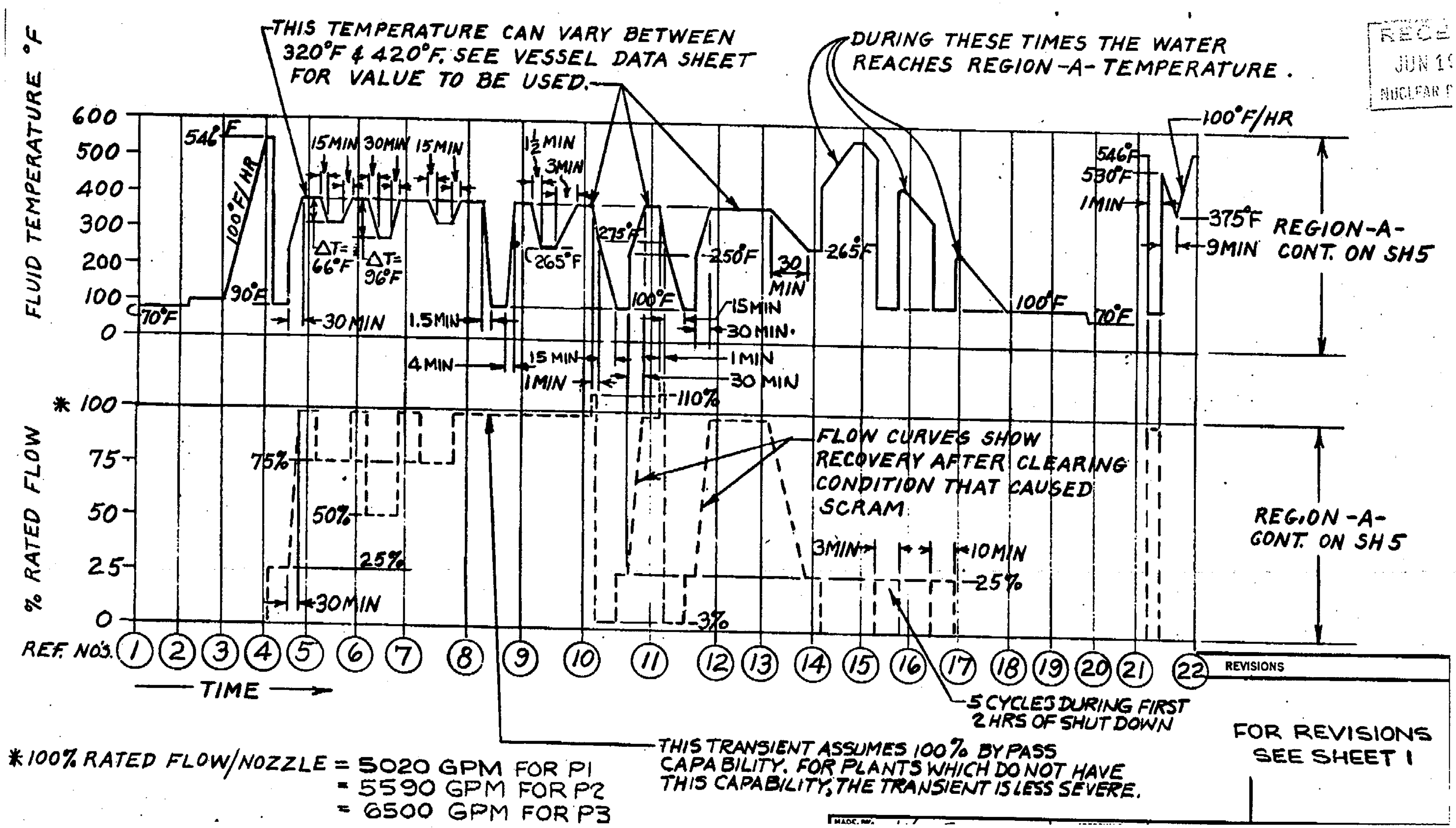
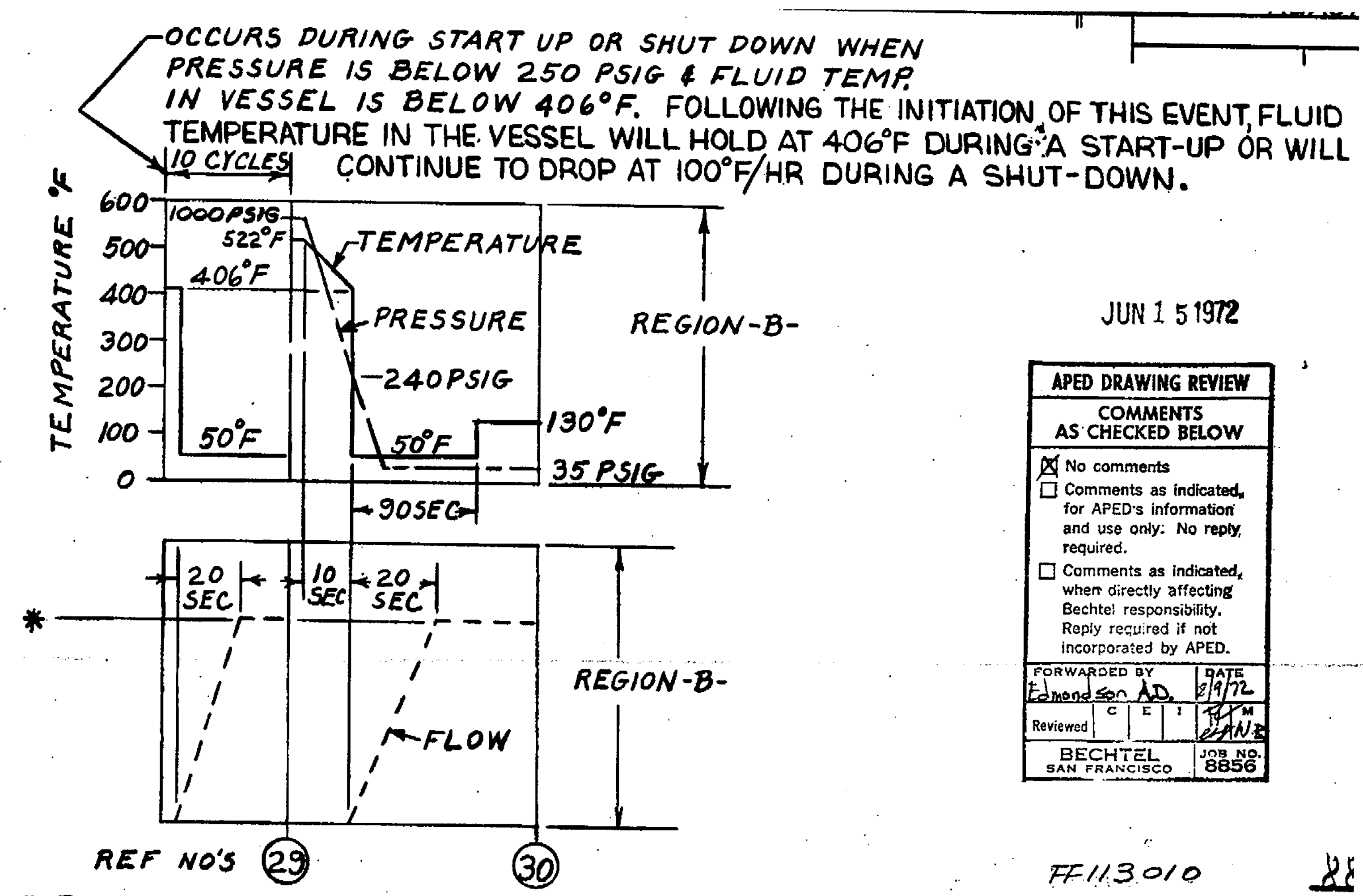


Figure A-6. Thermal Cycle Definitions for Core Spray Nozzle



* FLOW GPM = 5000 FOR P1
= 8200 FOR P2 ← SSES
= 6200 FOR P3

AT TIMES OTHER THAN SHOWN ABOVE THERE IS NO FLOW IN NOZZLE & TEMP. IS REGION-B- TEMPERATURE

Attachment B
Characteristic Thermal Definitions for Plant Hatch

Figure B-1. Heat Balance Diagram

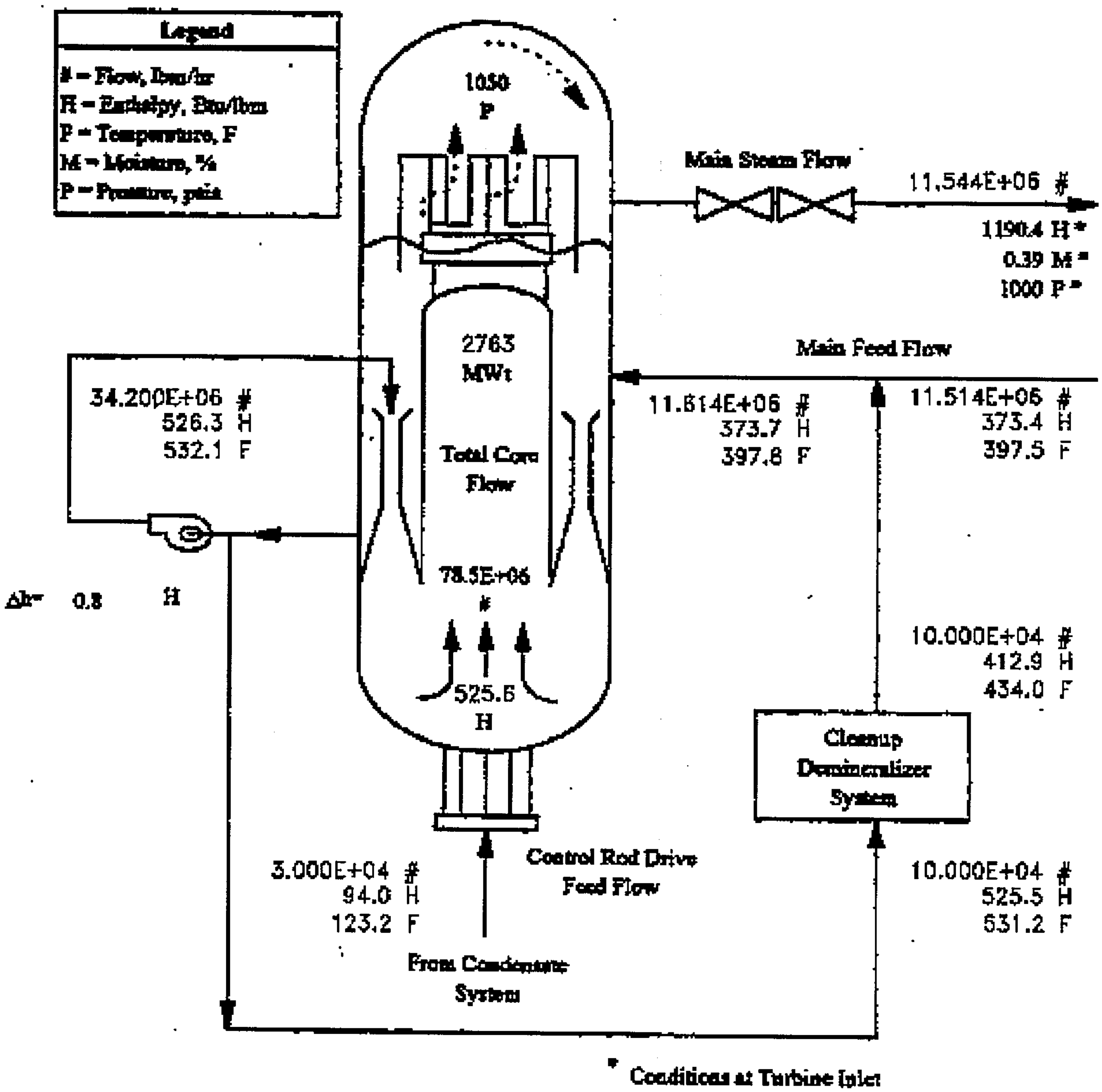


Figure B-2a. Thermal Cycle Definitions for RPV (Hatch 1)

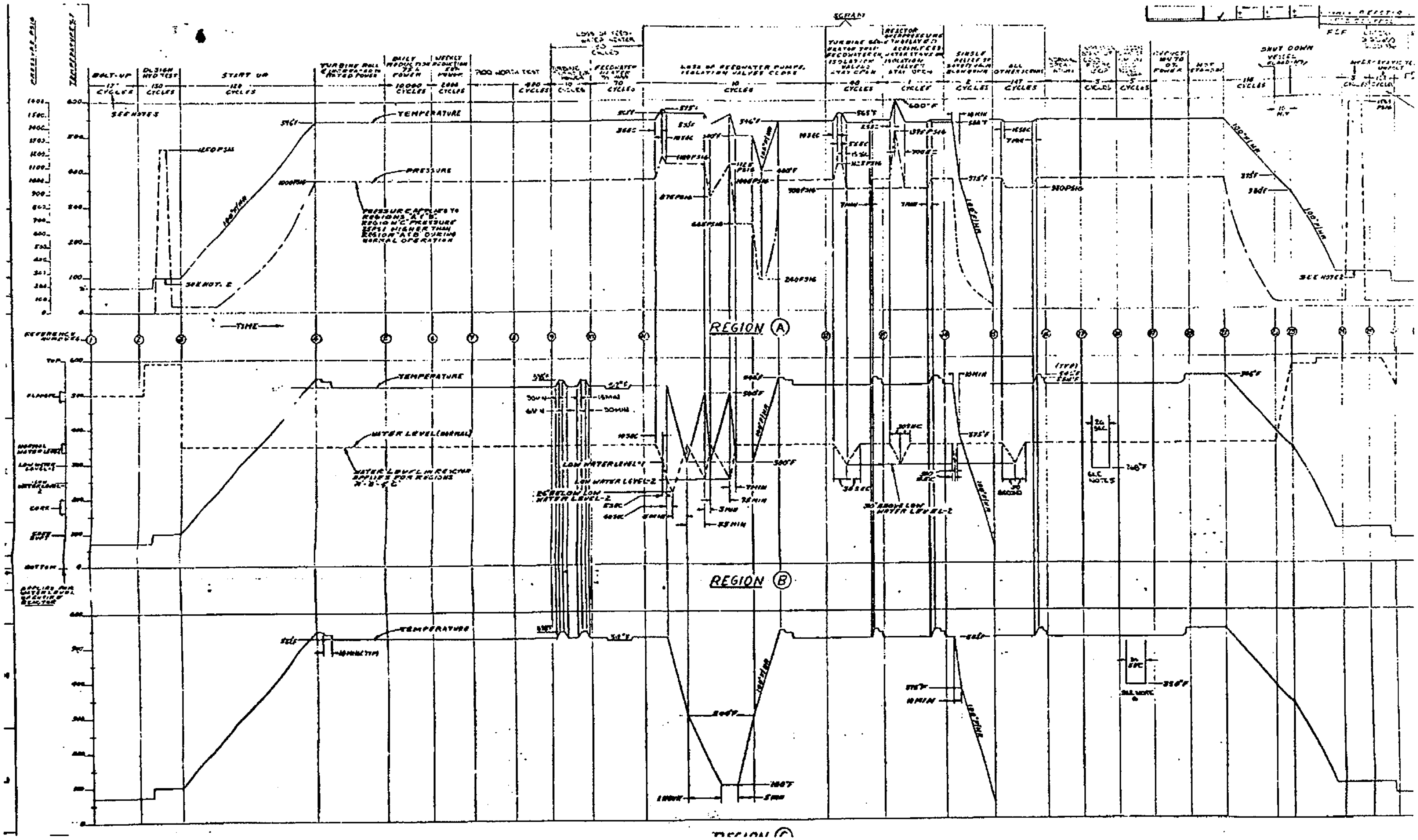


Figure B-2b. Thermal Cycle Definitions for RPV (Hatch 2)

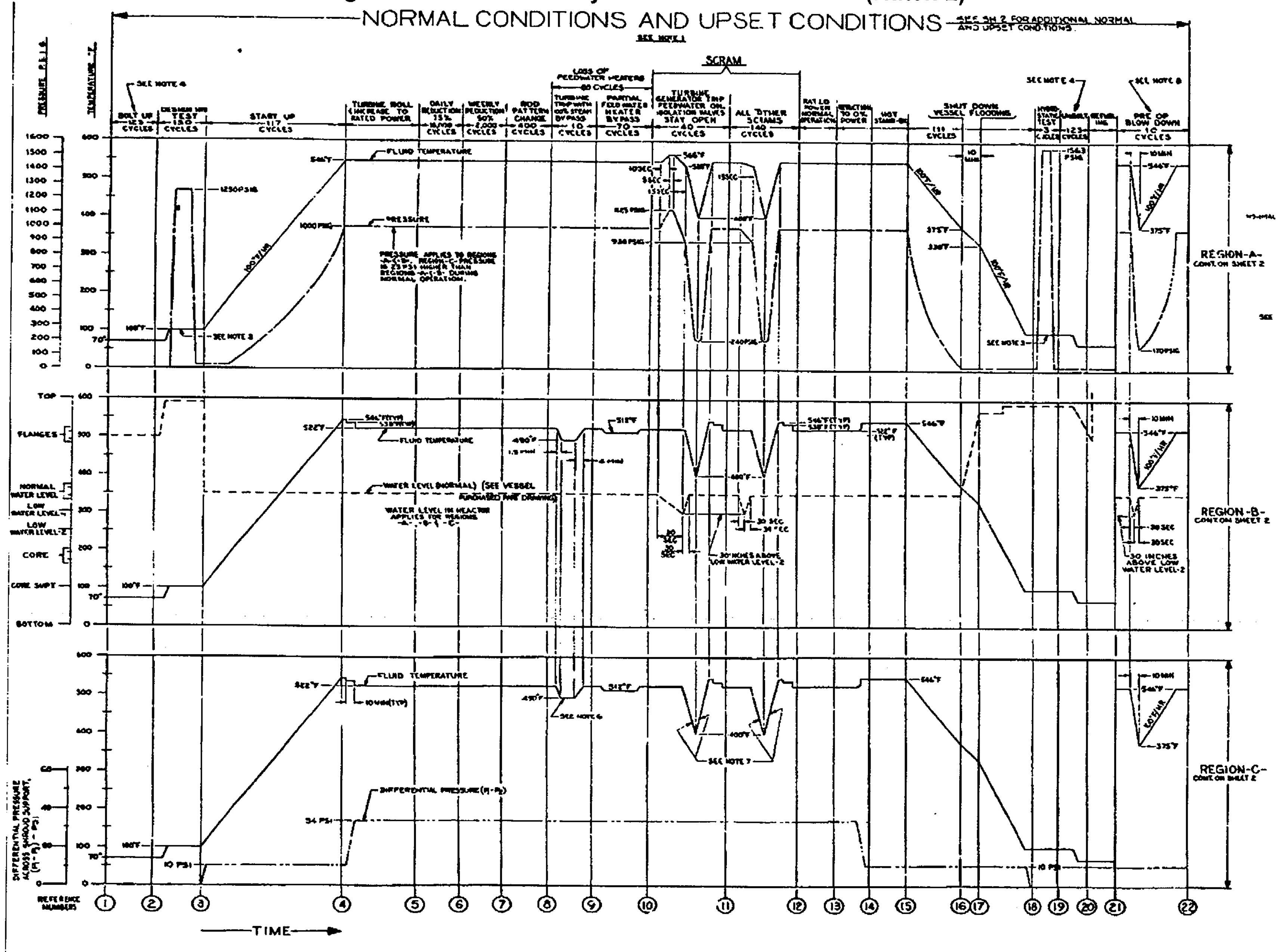


Figure B-3. Thermal Cycle Definitions for Recirculation Inlet Nozzle

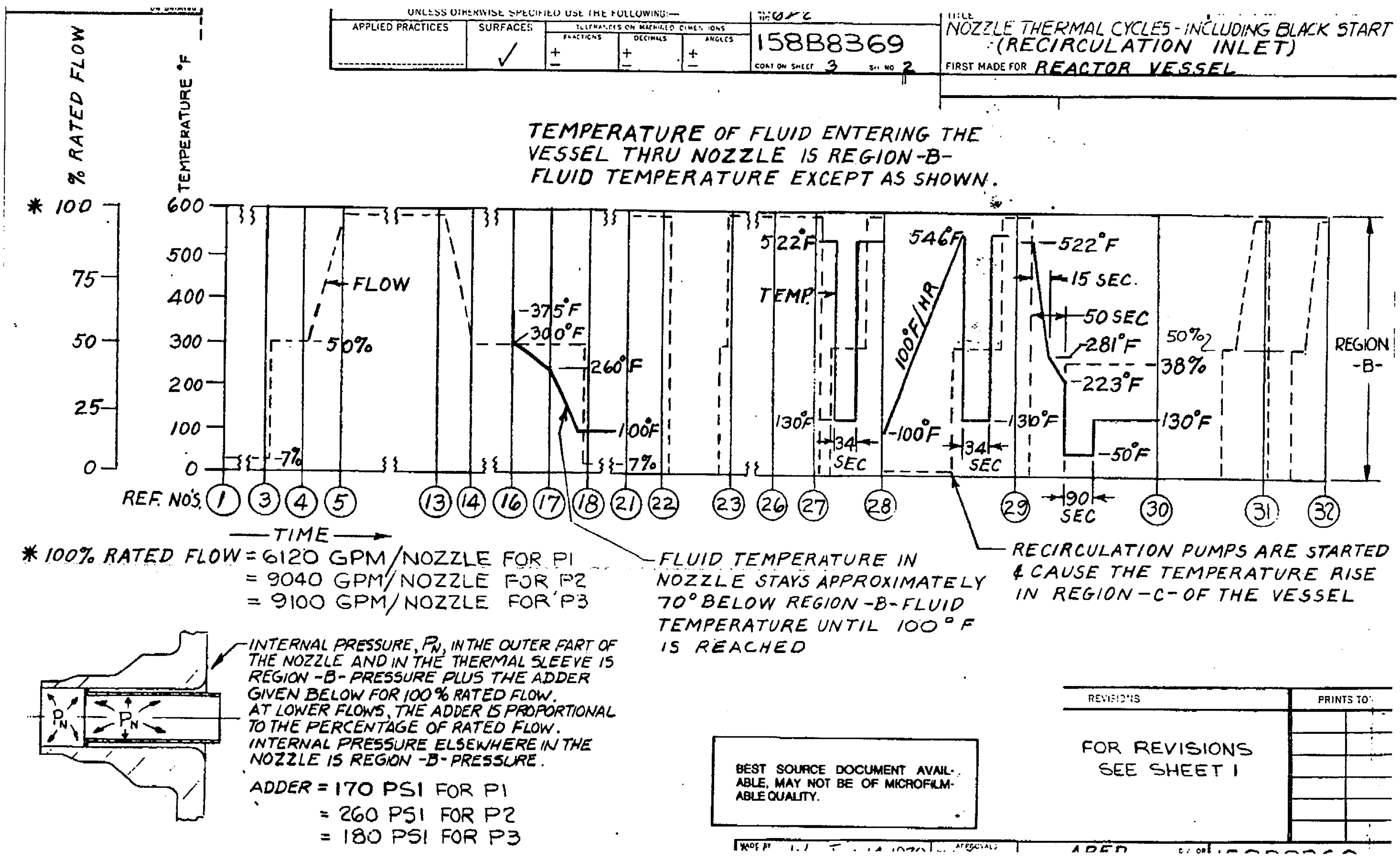


Figure B-4. Thermal Cycle Definitions for Recirculation Outlet Nozzle

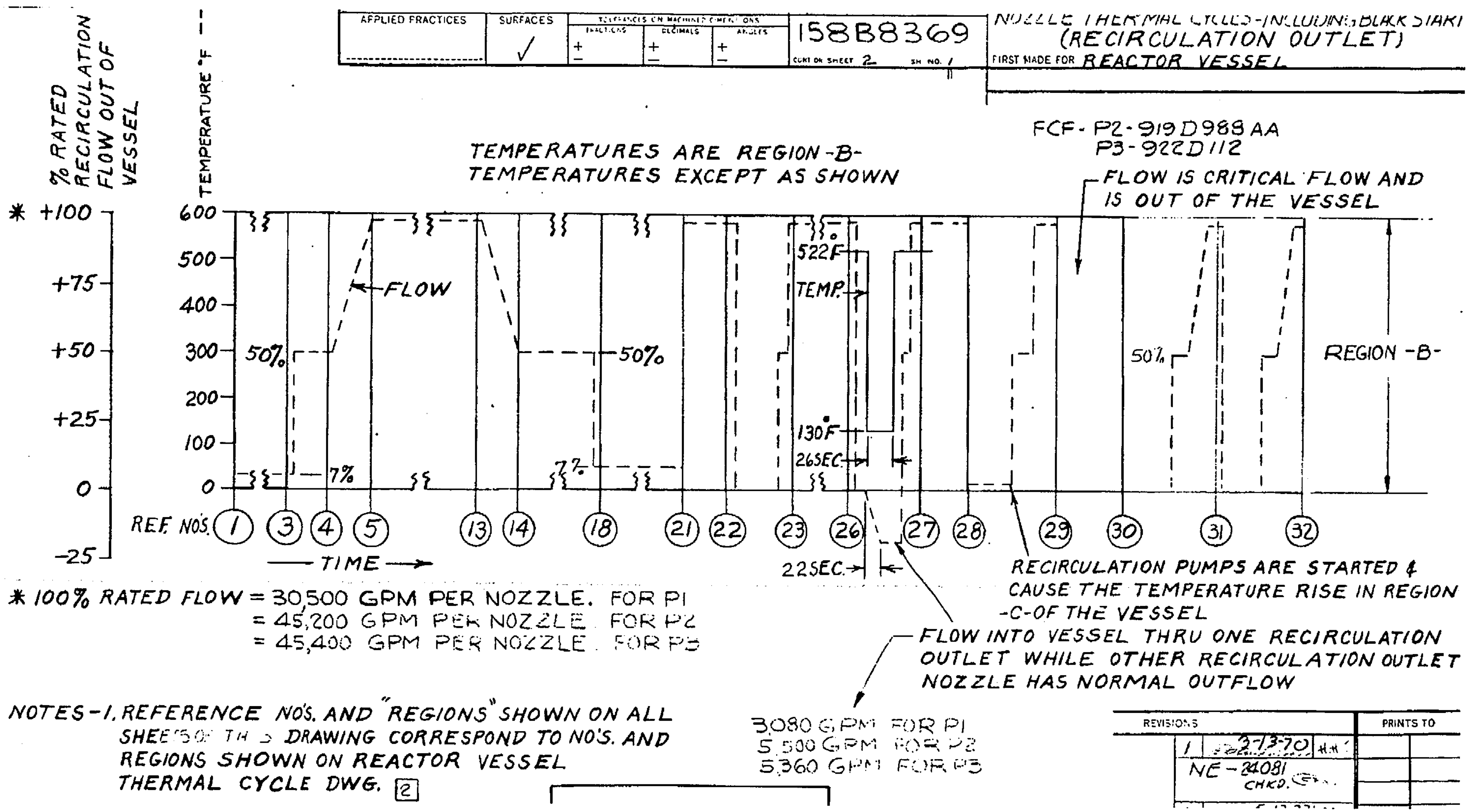


Figure B-5. Thermal Cycle Definitions for Feedwater Nozzle

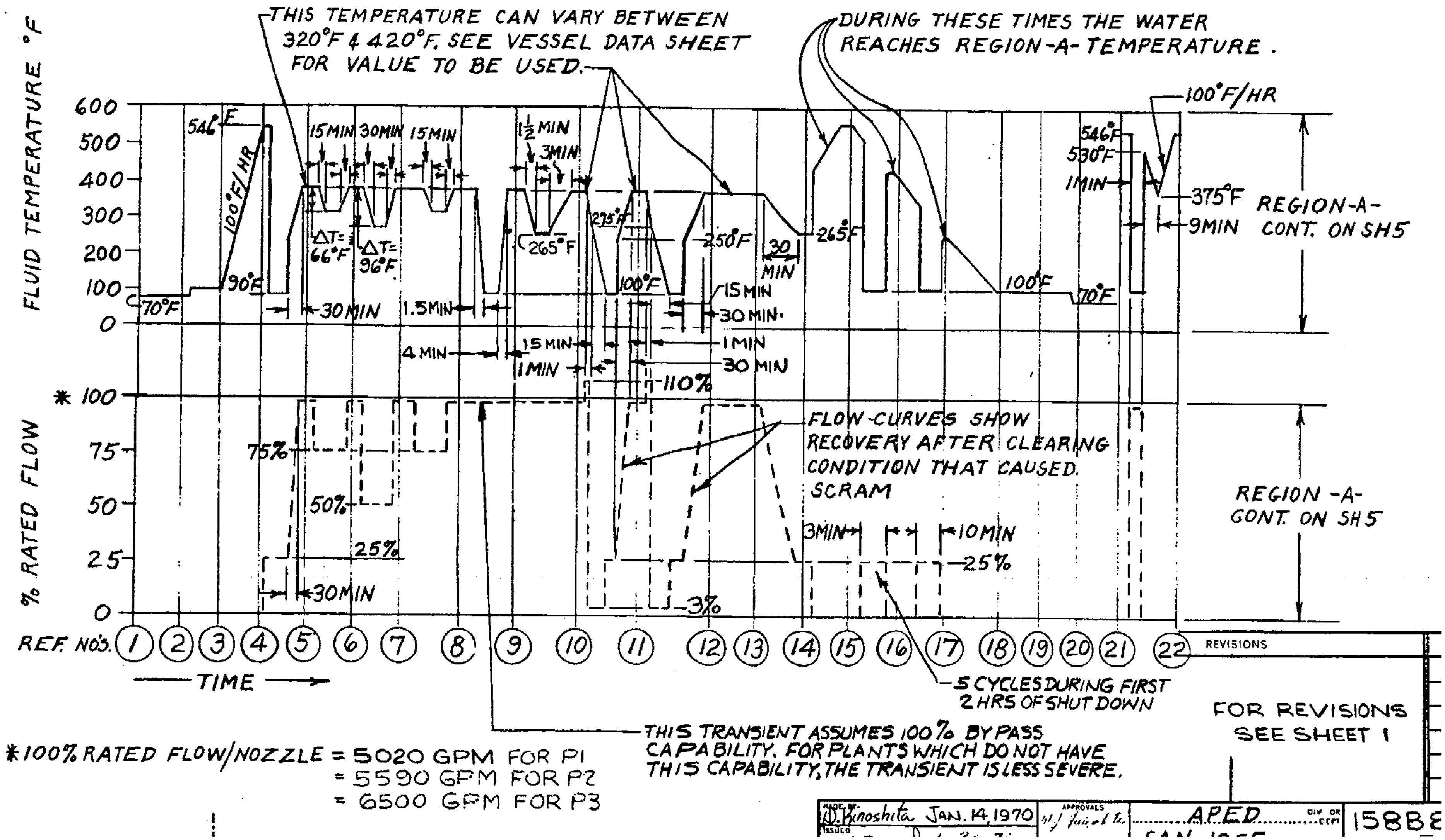
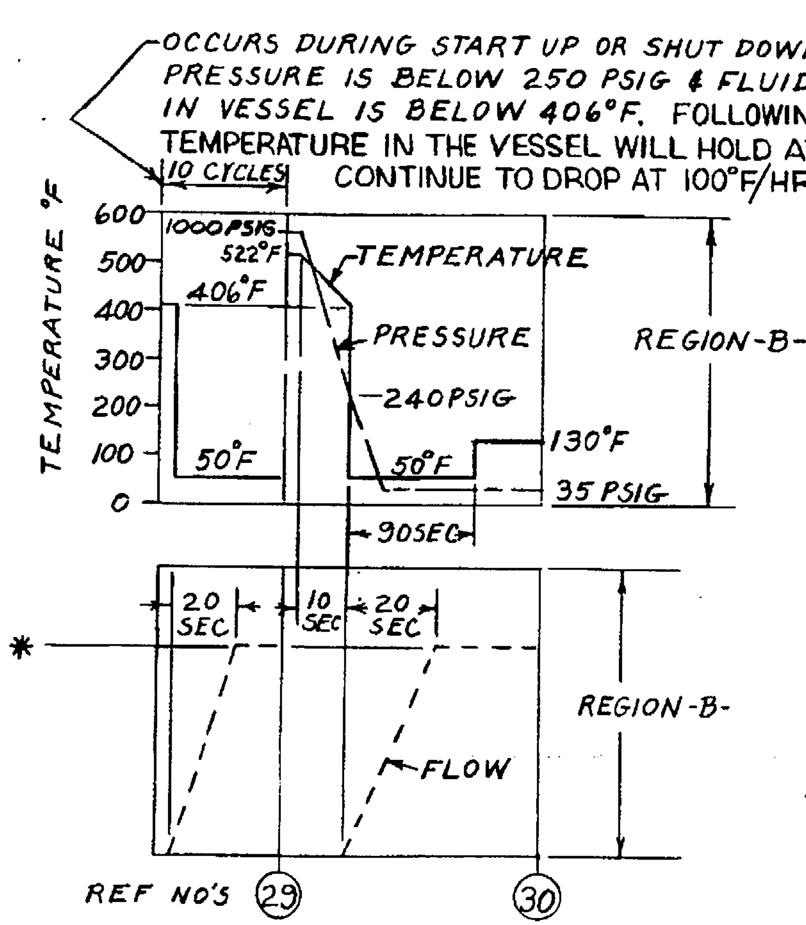


Figure B-6. Thermal Cycle Definitions for Core Spray Nozzle



*FLOW GPM = 5000 FOR P1
= 8200 FOR P2
= 6200 FOR P3

AT TIMES OTHER THAN SHOWN ABOVE THERE IS NO FLOW IN NOZZLE & TEMP. IS REGION-B- TEMPERATURE

ENCLOSURE 2

FSAR SUPPLEMENT

IN RESPONSE TO

DRAFT SER OPEN ITEM 3.0-1

REGARDING THE PLANT HATCH

LICENSE RENEWAL APPLICATION

June 4, 2001

TABLE OF CONTENTS

Chapter 18 AGING MANAGEMENT PROGRAMS/ACTIVITIES

LIST OF TABLES

18.0 AGING MANAGEMENT PROGRAMS/ACTIVITIES

18.1 INTRODUCTION

As part of the process of obtaining a renewed operating license, Southern Nuclear was required to demonstrate to the Nuclear Regulatory Commission that the aging effects determined to be applicable to in-scope systems, structures and components at Plant Hatch are adequately managed during the renewal term. The following program and activity descriptions represent the Plant Hatch commitments for managing aging of the in-scope systems, structures and components during the period of extended operation.

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).

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 chapter 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 term program or activity that will continue to be implemented during the period of extended operation.

- Enhanced Program (Activity): A current term program or activity that will be modified to manage aging during the renewal term. Enhancements will be implemented as shown in this chapter.

- New Program (Activity): A program or activity that did not exist in current term but was created as part of the license renewal process, which will manage aging during the renewal term. These programs or activities will be implemented for the renewal term as shown in this chapter.

Current term is defined as the term of the original operating license. Renewal term is defined as the period of operation beginning with receipt of the renewed operating license and ending sixty years from the effective date of the original, current term license. The period of extended operation is defined as the time period from expiration of the original, current term license to expiration of the renewed license.

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

10CFR54 (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 analyses through the renewal term.

Summary descriptions of TLAAs are provided in Section 18.5.

18.2 EXISTING PROGRAMS/ACTIVITIES

18.2.1 REACTOR WATER CHEMISTRY CONTROL

Reactor Water Chemistry Control is a mitigating activity designed to manage loss of material and cracking by controlling fluid purity and composition. Control of reactor water chemistry is based on the guidance and standards provided within EPRI TR-103515[1].

A. Program Scope

Portions of the following systems, structures and components within the scope of license renewal are directly or indirectly monitored by reactor water chemistry control:

- reactor assembly
- nuclear boiler
- reactor recirculation
- high pressure coolant injection
- reactor core isolation cooling
- electro-hydraulic control
- main condenser auxiliaries

B. Preventive or Mitigative Actions

Reactor water chemistry control mitigates loss of material and cracking by minimizing the oxidizing power, or electrochemical corrosion potential, of the reactor water. Reactor coolant system chemistry standards are met through the use of filtration and ion exchange operations accomplished by powdered resin condensate polishers. Hydrogen injection and Noble Metal Chemical Application have been utilized to further reduce the electrochemical corrosion potential of the reactor coolant.

C. Parameters Inspected or Monitored

EPRI TR-103515 provides the basis for the reactor coolant chemistry parameters monitored to assure adequate chemistry control. Control parameters include coolant conductivity, sulfate concentrations, and chloride concentrations.

D. Detection of Aging Effects

Reactor water chemistry control is a mitigative activity not intended to directly detect age-related degradation of reactor assembly and reactor coolant system components.

E. Monitoring and Trending

EPRI TR-103515 provides guidelines for trending, tracking, and regular evaluations of reactor water chemistry parameters. During normal power operations, sulfates, chlorides, and conductivity are monitored in accordance with the guidance provided in EPRI TR-103515.

F. Acceptance Criteria

Specific acceptance criteria are contained in EPRI TR-103515. Acceptance criteria vary based on plant operating conditions and the water chemistry mode currently in use (normal water chemistry or HWC).

18.2.2 CLOSED COOLING WATER CHEMISTRY CONTROL

Closed cooling water (CCW) chemistry control is a mitigating activity designed to manage loss of material by controlling fluid purity and composition. Control of CCW chemistry is based on the guidance provided within EPRI TR-107396[2].

A. Program Scope

While CCW chemistry control is applicable to all closed cycle cooling water systems, only limited portions of CCW systems are within the scope of license renewal. Operation of these systems is not vital to the safe shutdown of the plant under normal or accident conditions. However, certain portions of these systems are in scope to maintain primary containment integrity. Portions of the following systems are included:

- reactor building closed cooling water
- primary containment chill water (applicable to Unit 2 only)

B. Preventive or Mitigative Actions

Control of CCW chemistry manages loss of material through the use of corrosion inhibitor additions, biocide additions, and chemical additions to control pH. Concentrations of detrimental impurities are monitored. Should CCW chemistry parameters exceed the limitations established by the EPRI guidelines, appropriate corrective actions to minimize the potential for significantly increased corrosion rates and to restore closed cooling water purity will be taken.

C. Parameters Inspected or Monitored

EPRI TR-107396 provides the basis for CCW chemistry chemical additions and monitoring to assure adequate chemistry control. This guideline provides several different treatment options and provides recommendations for applicable control parameters.

Control parameters include pH (proper pH reduces corrosion rates and increases corrosion inhibitor effectiveness) and corrosion inhibitor concentrations. Diagnostic parameters include biocide concentrations and microbe populations; concentrations of detrimental impurities such as ammonia, chloride, and sulfate; and conductivity.

Additionally, RBCCW system carbon steel corrosion coupons are analyzed periodically to verify the effectiveness of the corrosion inhibitor system.

D. Detection of Aging Effects

CCW chemistry control is a mitigative activity and not intended to directly detect age-related degradation of components subjected to closed cooling water.

E. Monitoring and Trending

EPRI TR-107396 provides guidelines for trending, tracking, and regular evaluations of closed cooling water chemistry parameters.

F. Acceptance Criteria

Acceptance criteria for CCW chemistry control are based on the recommendations of EPRI TR-107396. This document specifies appropriate parameter limitations and analysis methods for adequate CCW chemistry control. EPRI TR-107396 contains recommended ranges and limitations for corrosion inhibitor concentrations, pH, and concentrations of detrimental impurities. In addition, bacteria populations are monitored to validate the effectiveness of biocide additions.

Carbon steel corrosion coupons are weighed periodically to assure that corrosion rates occurring within CCW systems are acceptable when evaluated against the EPRI TR-107396 target values.

18.2.3 DIESEL FUEL OIL TESTING

Diesel fuel oil testing is a mitigating activity designed to manage loss of material by monitoring fuel oil content for water and other contaminants.

A. Program Scope

Diesel fuel oil testing applies to the emergency diesel generator fuel oil storage tanks, the diesel generator fuel oil day tanks, and the associated transfer piping and components. It additionally covers the in-scope fire pump diesel fuel oil storage tanks and the associated piping and components. The following systems within the scope of license renewal are monitored directly or indirectly by diesel fuel oil testing.

- fuel oil supply
- fire protection

B. Preventive or Mitigative Actions

Diesel fuel oil testing activities mitigate loss of material by detecting intrusion of water or other contaminants to preclude loss of material due to corrosion. Program elements include sampling and analysis of new fuel prior to off loading to prevent contamination of stored fuel oil, and periodic sampling and analysis of stored fuel oil in storage and day tanks. Should the concentration of water or other contaminants exceed established acceptance criteria, appropriate actions to minimize the potential for significantly increased corrosion rates and reduce concentrations of water or other contaminants.

Additionally, biocide is added during the off loading of new fuel. The addition of a biocide, when properly controlled, minimizes the potential for microorganism growth and the potential for microbiologically influenced corrosion.

C. Parameters Inspected or Monitored

New fuel oil is sampled and analyzed for water and sediment content. Stored fuel oil is sampled and analyzed for water and sediment content and total particulate concentration.

D. Detection of Aging Effects

Diesel fuel oil testing is a mitigating activity not intended to directly detect age-related degradation of diesel fuel oil supply system components.

E. Monitoring and Trending

There are no monitoring or trending aspects associated with diesel fuel oil testing activities.

F. Acceptance Criteria

Stored fuel oil water and sediment and total particulate limits are established within the plant technical specifications and implementing procedures.

18.2.4 PLANT SERVICE WATER AND RHR SERVICE WATER CHEMISTRY CONTROL

Plant service water (PSW) and residual heat removal service water (RHRSW) chemical control activities are intended to reduce loss of material and loss of heat exchanger performance due to flow blockage (fouling) with service water system components through a biocide application program based on the requirements of Generic Letter 89-13[3].

A. Program Scope

Portions of the following systems within the scope of license renewal undergo biocide additions:

- residual heat removal service water
- plant service water
- reactor building HVAC
- traveling screen wash (PSW isolation valve only)
- control building HVAC

B. Preventive or Mitigative Actions

Sodium hypochlorite alone, or in conjunction with sodium bromide, is periodically injected into PSW to control biological growth in the service water systems. Additionally, this program is coordinated with the periodic operation of RHRSW to maximize chemical treatment in this system. These biocide additions are intended to reduce loss of material and flow blockage.

C. Parameters Inspected or Monitored

During plant PSW system chlorination and bromination, free available oxidant concentration is periodically monitored at the PSW discharge to the circulating water flume to ensure program efficacy.

The Plant Hatch NPDES Permit[4] requires periodic monitoring of plant effluent to the Altamaha River for residual oxidant.

D. Detection of Aging Effects

PSW and RHRSW chemistry control is a mitigative activity not intended to directly detect age-related degradation of PSW and RHRSW system components.

E. Monitoring and Trending

Free available oxidant is monitored during the treatment cycle to provide reasonable assurance that sufficient biocide is being added to meet the system chlorine demand and result in an effective residual free available oxidant concentration.

Sample results also provide indication that the program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

F. Acceptance Criteria

During chlorination and bromination, the PSW effluent should indicate a free available oxidant concentration equal to, or exceeding, the limitations specified within implementing procedures.

In accordance with the Plant Hatch NPDES Permit, the final plant effluent to the Altamaha River is sampled to detect the presence of any residual oxidant. These sample results are reported to the State of Georgia Department of Natural Resources on a quarterly basis.

18.2.5 FUEL POOL CHEMISTRY CONTROL

Fuel pool chemistry control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant systems and components by controlling fluid purity and composition. Control of fuel pool chemistry is based on the guidance provided within EPRI TR-103515[1].

A. Program Scope

Fuel pool chemistry control activities are applicable to the spent fuel pool liners, spent fuel pool plugs, the spent fuel pool gate, the refueling canal, spent fuel pool storage racks (including restraints), miscellaneous steel inside the spent fuel pool, and portions of the leak chase system.

B. Preventive or Mitigative Actions

Fuel pool chemistry control mitigates loss of material by minimizing detrimental ionic species and conductivity. Control of fuel pool chemistry is maintained through the use of filtration and ion exchange operations accomplished by filter / demineralizers. Should fuel pool water chemistry parameters exceed the limitations established by the EPRI guidelines, appropriate actions to minimize the potential for significantly increased corrosion rates and to restore fuel pool purity will be taken.

C. Parameters Inspected or Monitored

EPRI TR-103515 provides the basis for fuel pool chemistry parameters monitored to assure adequate chemistry control. EPRI specified fuel pool chemistry diagnostic parameters include conductivity, chloride and sulfate concentrations, and total organic carbon content. In addition, pH and filterable solids content are monitored.

D. Detection of Aging Effects

Fuel pool chemistry control is a mitigative activity not intended to directly detect age-related degradation of the fuel pool and associated internal structures.

E. Monitoring and Trending

EPRI TR-103515 provides guidelines for trending, tracking, and regular evaluations of fuel pool chemistry parameters. Sulfate and chloride concentrations, conductivity, and total organic carbon content are monitored in accordance with the guidance provided in EPRI TR-103515. In addition, pH and filterable solids content are monitored.

F. Acceptance Criteria

Specific acceptance criteria are contained within EPRI TR-103515.

18.2.6 DEMINERALIZED WATER AND CONDENSATE STORAGE TANK CHEMISTRY CONTROL

Demineralized water chemistry control is a mitigating activity designed to manage loss of material by controlling fluid purity and composition. Control of demineralized water chemistry is based on the guidance provided within EPRI TR-103515[1].

A. Program Scope

Portions of the following systems within the scope of license renewal are directly or indirectly monitored by demineralized water chemistry control.

- nuclear boiler
- control rod drive
- standby liquid control
- high pressure coolant injection
- reactor core isolation cooling

- condensate transfer and storage
- service demineralized water (primary containment function)
- emergency diesel generator auxiliaries

B. Preventive or Mitigative Actions

Demineralized water chemistry control mitigates loss of material by minimizing detrimental ionic species and conductivity. The demineralizer system provides demineralized water to meet tank chemistry limitations through the use of filtration, ion exchange and degasification processes. Control of demineralized water chemistry parameters, within the CST and DWST, is not maintained by any type of control system, such as ion exchange or filtration. Should demineralized water chemistry parameters exceed the limitations established by the EPRI guidelines, appropriate corrective actions to minimize the potential for significantly increased corrosion rates and to restore demineralized water purity will be taken.

C. Parameters Inspected or Monitored

EPRI TR-103515 provides the basis for demineralized water chemistry parameters monitored to assure adequate chemistry control. EPRI specified demineralized water chemistry diagnostic parameters include conductivity, chloride and sulfate concentrations, total organic carbon content, and silica content. In addition, pH is monitored.

D. Detection of Aging Effects

Demineralized water chemistry control is a mitigative activity not intended to directly detect age-related degradation of systems and components exposed to a demineralized water environment.

E. Monitoring and Trending

EPRI TR-103515 provides guidelines for trending, tracking, and regular evaluations of demineralized water chemistry parameters. Chloride and sulfate concentrations, total organic carbon content, and silica content are monitored in accordance with the guidance provided in EPRI TR-103515. In addition, pH is monitored.

F. Acceptance Criteria

Specific acceptance criteria are contained within EPRI TR-103515.

18.2.7 SUPPRESSION POOL CHEMISTRY CONTROL

Suppression pool chemistry control is a mitigating activity designed to manage loss of material and cracking by controlling fluid purity and composition. Control of suppression pool chemistry is based on the guidance provided within EPRI TR-103515[1].

A. Program Scope

Portions of the following systems, structures and components within the scope of license renewal are directly or indirectly monitored by suppression pool chemistry control:

- nuclear boiler
- residual heat removal
- core spray
- high pressure coolant injection
- reactor core isolation cooling
- primary containment purge and inerting (vacuum relief piping)
- containment isolation components having torus penetrations below the water level
- torus internal structures and components

B. Preventive or Mitigative Actions

Suppression pool chemistry control mitigates loss of material and cracking by minimizing detrimental ionic species and conductivity. Control of suppression pool chemistry parameters is not maintained by any type of control system, such as ion exchange or filtration. Should suppression pool chemistry parameters exceed the limitations established by the EPRI guidelines, appropriate corrective actions to minimize the potential for significantly increased corrosion rates and to restore suppression pool purity will be taken.

C. Parameters Inspected or Monitored

EPRI TR-103515 provides the basis for suppression pool chemistry parameters monitored to ensure adequate chemistry control. EPRI specified suppression pool chemistry diagnostic parameters include conductivity (zinc corrected), chloride and sulfate concentrations, and total organic carbon content.

D. Detection of Aging Effects

Suppression pool chemistry control is a mitigative activity not intended to directly detect age-related degradation of components exposed to a suppression pool environment.

E. Monitoring and Trending

EPRI TR-103515 provides guidelines for trending, tracking, and regular evaluations of suppression pool water chemistry parameters. Zinc corrected conductivity, sulfate and chloride concentrations, and total organic carbon content are monitored in accordance with the guidance provided in EPRI TR-103515.

F. Acceptance Criteria

Specific acceptance criteria are contained within EPRI TR-103515.

18.2.8 CORRECTIVE ACTIONS PROGRAM

SNC has established and implemented a QA Program that conforms to the criteria set forth in 10 CFR 50, Appendix B[5]. The QA Program addresses all aspects of quality assurance at Plant Hatch.

The two elements of the QA Program that are most pertinent to the aging management programs credited for license renewal are corrective actions and administrative controls. These elements are discussed in Chapter 17, and are outlined below. Corrective action and administrative control requirements apply to all components within the scope of license renewal.

A. Program Scope

The plant condition reporting process applies to all plant systems and components within the scope of license renewal. Administrative controls are in place for existing aging management programs and activities and for the currently required portions of enhanced programs and activities. Administrative controls will also be applied to new programs and activities as they are implemented. As a minimum, these programs and activities are or will be performed in accordance with written procedures. Those procedures are or will be reviewed and approved in accordance with Plant Hatch's 10 CFR 50, Appendix B, QA Program.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with the corrective actions program that are credited for license renewal.

C. Parameters Inspected or Monitored

No specific parameters are inspected or monitored as part of this program. Generally, when parameters inspected or monitored by other plant programs indicate a condition adverse to quality, the corrective actions program provides a means to correct the identified condition.

D. Detection of Aging Effects

Detecting aging effects is not part of the corrective actions program. The corrective actions program provides a means to address the aging effects identified by other aging management activities.

E. Monitoring and Trending

The corrective actions program does not monitor or trend aging effects. The corrective action program monitors corrective actions to assure identified conditions are addressed in a timely manner. Conditions that are identified as being adverse to quality are trended. Plant Hatch monitors significant conditions that are adverse to quality (significant occurrence reports) and requires a formal cause determination and corrective actions to prevent recurrence.

F. Acceptance Criteria

The corrective actions program does not include specific acceptance criteria for aging effects. Generally, when the acceptance criteria of other aging management activities are not met, the corrective actions program provides a means to assure appropriate corrective actions are taken.

G. Corrective Actions

The corrective action program is initiated following the determination of conditions adverse to quality, and documented as required by appropriate procedures. Various processes are used to identify problems requiring corrective action. The primary vehicle for initiating corrective action is the condition reporting process described in subsection 17.2.15.

The various components of the corrective action program provide for timely corrective actions, including root cause determination and prevention of recurrence. The QA program provides control over activities affecting the quality of systems, structures and components consistent with their importance to safety. In accordance with plant procedures, condition reports are analyzed for adverse trends. Any identified adverse trends are reported to the appropriate department for corrective action.

H. Confirmation Process

As described subsection 17.2.15: condition reports are reviewed to determine the regulatory reportability and significance. Those items determined to be significant conditions adverse to quality (significant occurrence reports) are also reviewed by the Plant Review Board. Corrective actions taken for significant items are reviewed for assurance that appropriate action has been taken.

I. Administrative Controls

Activities affecting quality are prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and are accomplished in accordance with these instructions, procedures, or drawings. They contain appropriate acceptance criteria and documentation requirements for determining whether important activities have been satisfactorily accomplished. Site procedures establish review and approval requirements.

18.2.9 INSERVICE INSPECTION PROGRAM

The inservice inspection (ISI) program is a condition monitoring program that provides for the implementation of ASME Section XI[6] in accordance with the provisions of 10 CFR 50.55a[7]. The ISI program also includes augmented examinations required to satisfy commitments made by SNC. The 10-year examination plan provides a systematic guide for performing required examinations. The period of extended operation will include the fifth and sixth inservice inspection intervals. Only a portion of the ISI program is credited for license renewal.

A. Program Scope

The ISI Program contains examination requirements and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as associated supports.

For license renewal, the ISI program is credited for monitoring potential age-related degradation in portions of the following systems:

- reactor assembly
- nuclear boiler
- reactor recirculation
- residual heat removal service water
- plant service water
- primary containment
- containment penetrations

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The ISI program utilizes visual, surface and volumetric examinations to detect loss of material, cracking, and loss of preload.

D. Detection of Aging Effects

Three types of inspection methods are used for inservice examination. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in ASME Section XI paragraph IWA-2210, surface examinations are performed as defined in IWA-2220, and volumetric examinations are performed as defined in IWA-2230.

E. Monitoring and Trending

Deficiencies discovered during the performance of the program activities are documented in accordance with ISI program implementing procedures and are monitored in accordance with ASME Code requirements. The plant corrective actions program addresses deficiencies requiring repair or replacement.

F. Acceptance Criteria

Components not meeting the acceptance criteria defined in ASME Section XI, Tables IWB-2500-1, IWC-2500-1, IWD-2500-1, and IWE-2500 are evaluated, repaired, or replaced prior to return to service.

18.2.10 OVERHEAD CRANE AND REFUELING PLATFORM INSPECTIONS

The overhead crane and refueling platform inspection (OC&RPI) procedures were developed using ANSI B30.2.0-1976[8] and NUREG-0612[9]. Inspection procedures for fuel handling equipment were developed using ANSI B30.9-1971[10], ANSI/ASME B30.10-1982[11], ANSI N14.6-1978[12] and NUREG-0612.

The OC&RPI program ensures the overhead crane and refueling platform are capable of safely handling loads. The aging management review for passive structural elements identified one aging effect, loss of material due to corrosion, as requiring management. This program also satisfies 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.

A. Program Scope

The OC&RPI program will perform inspections on the following systems that are within the scope of license renewal.

- Fuel and Control Rod Handling Equipment
- Refueling Floor Cranes and Hoists

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The OC&RPI provides for visual inspection of the contacting surfaces of the steel rails and the passive structural load bearing components of the overhead crane and refueling platform such as crane girder, rail and bolts. These inspections are intended to detect loss of material due to corrosion.

D. Detection of Aging Effects

Visual inspections are performed to detect the loss of material.

E. Monitoring and Trending

Inspection test results are maintained in plant records. Engineering personnel track and trend results in accordance with implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the OC&RPI is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.11 TORQUE ACTIVITIES

Torque activities mitigate loss of preload through use of proper torque techniques. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities. Torque activities are based on the guidance of EPRI NP-5769.[12] This EPRI document has been generally endorsed by the NRC in NUREG 1339.

Other codes and standards considered during development of the torquing procedure were ASME, Section VIII,[13] Div. 1, App. 2, ASME, Section II,[14] ASTM Standards,[15] Section 15, Volume 15.08, and ASME B31.1.[16]

A. Program Scope

Torque activities are applicable to bolts, studs, nuts, and washers within systems in the scope of license renewal.

B. Preventive or Mitigative Actions

The torque activities require that appropriate hardware is used in bolted connections. Additionally, proper torque techniques assure that adequate preload is applied to the connection. These attributes of the torque activities assure that loss of preload is mitigated.

C. Parameters Inspected or Monitored

There are no parameters inspected or monitored with this activity.

D. Detection of Aging Effects

There are no actions performed by this activity to detect aging effects.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of preload will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. Any significant loss of preload is noted and corrective actions will be implemented in accordance with the corrective action program.

18.2.12 COMPONENT CYCLIC OR TRANSIENT LIMIT PROGRAM

The component cyclic or transient limit program (CCTLP) is a surveillance program required by Technical Specifications. It is a monitoring program designed to track cyclic and transient occurrences to assure 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.

Plant cycles and transients that significantly contribute to fatigue usage of Class 1 components have been identified. Periodically, each unit's operating records are reviewed to determine the number of design transients that have occurred since the last time cumulative usage factor (CUF) was calculated. Applying the actual cycles that have occurred to the formulas that represent design severity of cycles results in sufficient conservatism, including effects due to environmental factors, that cracking due to thermal fatigue is not expected as long as the CUF does not exceed 1.0.

A. Program Scope

The scope includes the reactor pressure vessel (RPV), the torus, and all Class 1 piping. The Unit 1 FSAR, section 4.2.5, and section 5.4.6.4, document the bounding RPV locations monitored. The four limiting high stress RPV boundary components are the RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles. The CCTLP also monitors the fatigue for the critical locations of the torus and Class 1 piping. For Unit 1, the Class 1 piping locations that are monitored are the limiting locations on the reactor vessel equalizer piping, the core spray piping, the standby liquid control piping, the feedwater, high pressure coolant injection, reactor core isolation cooling, reactor water cleanup piping, and the main steam piping. For Unit 2, the monitored piping is the limiting locations for the feedwater piping, the primary steam condensate drainage, and the main steam piping.

The monitoring formulas in the CCTLP account for any effects due to power uprate or extended power uprate and contain sufficient conservatism to account for environmental effects of reactor water when applicable. Therefore, the bounding locations for the reactor pressure vessel, torus, and all Class 1 piping significantly susceptible to cracking due to fatigue are monitored.

The scope of the CCTLP includes long-lived passive components in the following systems or structures, within the scope of license renewal:

- reactor pressure vessel
- nuclear boiler
- reactor recirculation
- primary containment
- containment penetrations
- core spray
- standby liquid control
- feedwater
- high pressure coolant injection
- reactor core isolation cooling
- reactor water cleanup
- main steam
- primary steam condensate drains

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

To address cracking, the CCTLP monitors the CUF for the critical locations in the RPV, the torus, and the Class 1 piping by events that can significantly contribute to the fatigue of components at the locations.

D. Detection of Aging Effects

This program does not detect cracking.

E. Monitoring and Trending

The CCTLP utilizes plant records to ascertain if events that could significantly contribute to components CUF have occurred. The calculations of the component CUF are documented in the plant records. Engineering personnel track and trend the CUF in accordance with the CCTLP implementing procedures.

F. Acceptance Criteria

The CCTLP tracks high fatigue usage components to assure that the plant will continue to meet the ASME Code, Section III[17], and CUF design requirement value of less than or equal to 1.0. If the 60-year CUF is projected to exceed 1.0, a condition report is initiated to determine and take appropriate corrective action in accordance with the corrective actions program.

18.2.13 PLANT SERVICE WATER AND RHR SERVICE WATER INSPECTION PROGRAM

During the period of extended operation, the following aging effects could occur to plant service water (PSW) and RHR service water (RHRSW) passive components within the scope of license renewal: loss of material, loss of heat exchanger performance, flow blockage (fouling), and cracking (of RHR heat exchanger tubes). The plant service water and RHR service water inspection program manages these effects for those components. This program is designed to detect wall thickness degradation, fouling or cracking in the components associated with the PSW and RHRSW systems. The specific inspection locations in the PSW and RHRSW systems are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are infrequently used piping (stagnated water), submerged piping, piping with low fluid velocity, small diameter piping, backing rings, socket welds, and the heat affected zone of a weld. 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. Locations prone to cracking include locations susceptible to vibration fatigue and stress corrosion cracking (RHR heat exchanger tubes). Locations prone to erosion include the areas with high velocity.

This program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13[18]. In addition, other industry standards and codes are used as guidance.

A. Program Scope

The PSW and RHRSW inspection program will inspect those portions of the following systems that are within the scope of license renewal:

- residual heat removal and residual heat removal service water
- plant service water
- reactor building HVAC
- travelling water screen wash isolation valve
- control building HVAC

B. Preventive or Mitigative Actions

The PSW and RHRSW piping inspection program requires that divers visually inspect the intake structure pump suction pit. Any accumulations of biological fouling organisms, sediment, and corrosion products found during the inspection are removed to prevent these foreign materials from entering the system.

C. Parameters Inspected or Monitored

The PSW and RHRSW piping inspection program provides for visual and volumetric examinations intended to detect wall thinning, surface indications, and reduction of flow area within service water system components. This program also provides hardness testing to detect selective leaching.

D. Detection of Aging Effects

PSW and RHRSW piping inspection program inspections to detect loss of material include volumetric inspections (radiographic and ultrasonic), and visual inspections (including use of depth gages). Volumetric inspections, visual inspections, and flow testing are utilized to detect flow blockage (fouling) and loss of heat exchanger performance. Additionally, the program has provisions for hardness testing on brass and gray cast iron in the PSW or RHRSW system.

E. Monitoring and Trending

Inspection and hardness test results are maintained in plant records. Engineering personnel track and trend results in accordance with PSW and RHRSW piping inspection program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional testing will be performed. Any significant degradation of components inspected or tested by the PSW and RHRSW piping inspection program is noted and corrective actions will be implemented in accordance with the existing corrective actions program.

18.2.14 PRIMARY CONTAINMENT LEAKAGE RATE TESTING PROGRAM

Primary containment leakage rate testing program (PCLRTP) satisfies the requirements that primary containment meets the leakage-rate test requirements in either Option A or B of 10 CFR 50, Appendix J[19]. Plant Hatch has opted for option B which identifies the performance-based requirements and criteria for preoperational and subsequent periodic leakage-rate testing. This program is designed to ensure that (a) leakage through the primary containment or systems and components penetrating the primary containment does not exceed allowable leakage rates specified in the Technical Specifications and (b) integrity of the containment structure is maintained during its service life. The PCLRTP manages the aging effect of loss of material.

There are three performance based leakage test requirements: Type A [also known as integrated leak rate test (ILRT)], Type B, and Type C [also known as local leak rate test (LLRT)]. Type A tests measure the containment system overall integrated leakage rate and are conducted under conditions representing design basis loss-of-coolant accident containment peak pressure. Type B pneumatic tests are performed to detect and measure local leakage rates across pressure retaining, leakage-limiting boundaries. Type C pneumatic tests are performed to measure containment isolation valve leakage rates. These tests ensure the integrity of the overall containment system as a barrier to fission product release following a postulated accident.

The PCLRTP was developed through the use of 10CFR50, Appendix J, Option B, Regulatory Guide 1.163[20], NEI 94-01[21], and ANSI/ANS 56.8-1994[22] and Bechtel Topical Report BN-TOP-1[23]. The allowable leakage rate (L_a) with margin is based on as specified in the Technical Specifications[24].

A. Program Scope

The PCLRTP applies to the structures, systems and components within the scope of license renewal. These components include the steel primary containment, containment penetrations, and containment internal structures that perform a pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive (CRD) removal hatches.

B. Preventive or Mitigative Actions

There are no preventive or mitigative actions associated with this program.

C. Parameters Inspected or Monitored

The PCLRTP provides for visual inspection and performance testing intended to detect loss of material.

A general visual inspection of the accessible interior and exterior surfaces of the drywell and torus are performed prior to conducting a Type A test. The containment pressure boundary integrity is monitored by performance testing.

D. Detection of Aging Effects

The containment leakage rate testing program utilizes pressure tests of containment to verify that primary containment pressure integrity remains intact. In addition, general visual inspections are conducted prior to performing a type A (ILRT) test.

E. Monitoring and Trending

Inspection and performance testing results are maintained in plant records. Engineering personel track and trend results in accordance with PCLRTP implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. Any significant degradation of components tested and inspected by PCLRTP is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.15 BOILING WATER REACTOR VESSEL AND INTERNALS PROGRAM

The boiling water reactor pressure vessel and internals inspection program (BWRVIP) developed inspection and evaluation reports for the reactor pressure vessel (RPV) and reactor internal components and submitted them to the NRC for review and approval. These reports address both the current term and the extended term of operation. Additionally, these reports specifically addressed the reactor pressure vessel components and reactor internals relative to the requirements of 10 CFR 54[25]. The BWRVIP criteria documented in the final NRC safety evaluations regarding these inspections and evaluation reports are used, except where a specific exception has been identified to the NRC.

For the RPV and reactor internals, applicable ASME Section XI[6] inservice inspection requirements and applicable augmented inspection requirements mandated by NRC correspondence, such as NUREG 0619[26], are considered within BWRVIP inspection and evaluation reports and are addressed by BWRVIP inspection requirements.

A. Program Scope

Reactor pressure vessel components which require aging management for license renewal include RPV, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles penetration seals, core ΔP and standby liquid control nozzle, RPV support skirt, closure studs, attachment welds for internal core spray pipe, jet pump riser brace pad, and shroud support.

Reactor internals which require aging management for license renewal are the shroud and associated shroud repair hardware, shroud supports, internal core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, top guides, and dry tubes.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

BWRVIP inspection and evaluation reports contain approved inspection methodologies to detect cracking of RPV and reactor internals.

D. Detection of Aging Effects

The BWRVIP inspection and evaluation documents provide for RPV and reactor internals examination utilizing a combination of ultrasonic, visual, and surface methods. Pressure testing is also utilized. The specific methods to be used and the frequency of examination are specified in the applicable BWRVIP inspection and evaluation report, unless a specific exception is identified to the NRC.

E. Monitoring and Trending

Monitoring requirements for the detrimental effects of aging within reactor assembly components are specified within BWRVIP inspection and evaluation reports. The frequency of examination specified within applicable BWRVIP inspection and evaluation reports 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.

F. Acceptance Criteria

BWRVIP inspection and evaluation reports provide specific acceptance criteria and proper corrective actions. BWRVIP inspection and evaluation reports applicable to Plant Hatch reactor assembly components are listed below:

BWRVIP-18	Core Spray Internals[27]
BWRVIP-26	Top Guide[28]
BWRVIP-27	Penetrations[29]
BWRVIP-38	Shroud Support and Connecting Welds[30]
BWRVIP-41	Jet Pump Assembly[31]
BWRVIP-47	Control Rod Guide Tube[32]
BWRVIP-48	RPV ID Attachment Welds[33]
BWRVIP-74	RPV Shell and Heads, Nozzles, and Appurtenances[34]
BWRVIP-76	Shroud (including repair hardware) [35]

18.2.16 WETTED CABLE ACTIVITIES

Several 4 kV power cables and transformer feeder cables within the scope of license renewal run through conduits that junction in below grade pull boxes located outside. These cables might become immersed in rainwater if left unattended. In turn, wetted cable insulation might result in loss of insulation resistance.

A. Program Scope

The wetted cable activities monitor insulated cable in portions of the following systems that are within the scope of license renewal.

- residual heat removal system
- core spray system
- plant service water system

B. Preventive or Mitigative Actions

By routinely monitoring for water in the applicable pull boxes, and draining accumulated water when necessary, these activities prevent or mitigate loss of insulation resistance that might otherwise occur if cables were left immersed.

C. Parameters Inspected or Monitored

Wetted cable activities provide for megger testing and polarization index comparison of cables to measure cable insulation resistance. A reduction in cable insulation resistance indicates aging degradation due to loss of insulation resistance.

D. Detection of Aging Effects

Periodic megger and polarization index testing are the methods by which actual power cable insulation degradation is detected, regardless of whether or not the degradation was attributable to immersion.

E. Monitoring and Trending

Inspection and test results are maintained in plant records. Engineering personnel track and trend results in accordance with wetted cable activities implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of insulation resistance will be evaluated by engineering. Any significant degradation of components tested by the wetted cable activities is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.2.17 REACTOR PRESSURE VESSEL MATERIALS SURVEILLANCE PROGRAM

The reactor pressure vessel (RPV) materials surveillance program meets the requirements of 10 CFR 50, Appendix H[36]. This program provides for testing and evaluation of in-core surveillance capsule tensile and charpy specimens and evaluation of capsule neutron exposure for the purpose of evaluating the results of operation on RPV beltline material upper shelf energy (USE) and nil-ductility transition temperature (NDTT).

Compliance with 10 CFR 50, Appendix H may be demonstrated either through an NRC approved site specific program or an integrated surveillance program that meets the technical requirements documented within BWRVIP-78[37].

A. Program Scope

Reactor pressure vessel components requiring aging management within the scope of the RPV materials surveillance program include only RPV ferritic plates and welds within the beltline region.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The RPV materials surveillance program provides for evaluation of charpy and tensile specimens and flux wires to estimate changes in the USE and NDTT of beltline ferritic materials.

D. Detection of Aging Effects

The RPV materials surveillance program monitors reduction of fracture toughness within ferritic RPV beltline materials. Testing methodologies are provided within ASTM E185[38], with revision, as applicable. See Unit 1 FSAR section 4.2 and section 5.2.

E. Monitoring and Trending

Reductions in ferritic vessel beltline material fracture toughness are monitored by the surveillance program. For the period of extended operation, the capsule removal schedule will be determined by the integrated surveillance program or an NRC approved site specific program.

F. Acceptance Criteria

Data obtained from the materials surveillance program. or from use of estimation methodologies provided within NRC Regulatory Guide 1.99[39], is ultimately utilized to evaluate upper shelf energy reduction and shifts in NDTT. Limits are imposed on upper shelf energy, NDTT, and operating pressure and temperature by 10 CFR 50 Appendix G[40].

18.2.18 DIESEL GENERATOR MAINTENANCE ACTIVITIES

The diesel generator maintenance activities (DGMA) provide for management of the aging effects of loss of material, cracking, and loss of heat exchanger performance for the emergency diesel generator (EDG) components that are within the scope of license renewal. The DGMA are limited to the EDG components on the EDG skid.

A. Program Scope

The DGMA address the aging effects for the emergency diesel generator skid-mounted components that contain jacket cooling water, lubrication oil, scavenging air, and raw water. The components are limited to the piping, tubing, restricting orifices, valve bodies, pump casings, heat exchangers, heater casings, filter housings, strainer bodies, and strainer elements.

B. Preventive or Mitigative Actions

The DGMA are performance monitoring activities and preventive maintenance activities, as well as surveillance tests. During these activities, aging effects (loss of material, cracking, and loss of heat exchanger performance) that adversely impact the performance of the EDG component intended functions can be identified.

The DGMA also include periodic preventive maintenance on the EDG components. These maintenance activities include disassembly and refurbishment of the components, as needed. Replacement of adversely affected components (and fluids, such as the jacket cooling water and lubrication oil) is also an option within the DGMA.

C. Parameters Inspected or Monitored

The DGMA include inspections that are visual, chemical, and also performance based. Lubricating oil is tested for wear products, water, fuel oil, and anti-freeze. Heat exchanger inspections visually inspect heat exchanger water boxes, tubes, tube sheets, and sacrificial zinc rods for damage, debris, deposits, and evidence of corrosion to discern the impact of loss of material. Heat exchanger inspections also include the option for eddy current testing of the heat exchanger tubes (exposed to raw water) on an as-needed basis. The quality of the ethylene glycol solution in the jacket water cooling system is monitored during maintenance on the EDGs to ensure proper performance.

D. Detection of Aging Effects

DGMA are not intended to directly detect loss of material or cracking within EDG components. The DGMA can detect loss of heat exchanger performance in the heat exchangers through pressure and temperature instrumentation.

E. Monitoring and Trending

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with DGMA implementing procedures.

F. Acceptance Criteria

For performance tests, the acceptance criteria are listed in the specific plant procedures and are intended to ensure that system operating temperatures, pressures, and expansion tank levels are within the acceptable operating ranges. For preventive maintenance activities, the acceptance criteria are also contained within the maintenance procedures and are commensurate with the safety significance of the component inspected. After maintenance, the performance of the components must be such that the performance test criteria are satisfied. Unacceptable inspection and testing results are addressed through the corrective actions program.

18.3 ENHANCED PROGRAMS/ACTVITIES

18.3.1 FIRE PROTECTION ACTIVITIES

Fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. Fire protection activities provide assurance that loss of material, cracking, flow blockage, and changes in material properties will not prevent the performance of necessary safe shutdown functions.

A. Program Scope

The Plant Hatch fire protection activities credited for license renewal include those portions of fire protection systems identified in the Fire Hazards Analysis (FHA) as forming part of the CLB. These include passive long-lived components in water based and gaseous fire suppression systems, the fire pump diesel fuel oil supply system (tanks and piping), fire doors, fire penetration seals, fire dampers, and cable tray enclosures. All of these components are part of the fire protection system.

The current term fire protection activities have been enhanced for the period of extended operation to include periodic inspection of water suppression system strainers and sprinkler heads.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

B. Preventive or Mitigative Actions

Flushing of loop headers removes corrosion product buildup and ensures adequate flow through the system. Other than flushes, there are no preventive or mitigative attributes associated with the condition and performance monitoring elements of this program.

C. Parameters Inspected or Monitored

Surveillance and inspection of in-scope fire protection system components are performed in accordance with the frequencies and requirements the applicable portions of both Appendix B of the FHA and plant procedures that cover in-scope components. The activities performed to manage the effects of aging for these systems are listed in Table 18.3.1 - 1.

An inspection, called "Sprinkler Head Inspections," will be performed periodically for closed sprinkler heads in the scope of license renewal. The first inspection will take place after 50 years of service and subsequent inspections at 10-year intervals thereafter. Consistent with the guidance in NFPA-25[57], a random sampling of each type of closed sprinkler head in the scope of license renewal will be submitted to a recognized laboratory for testing. Based on the results, corrective actions will be accomplished, if required, to assure continued sprinkler head function during the period of extended operation.

D. Detection of Aging Effects

Detection of flow blockage, loss of material, cracking, and changes in material properties are accomplished directly by visual examinations of component surfaces and laboratory testing and indirectly through the use of flow or functional testing.

E. Monitoring and Trending

Inspection and performance testing results are maintained in plant records. Engineering track and trend results in accordance with site procedures.

F. Acceptance Criteria

Any significant degradation of fire protection system components that is observed during visual inspections or performance testing activities is noted and corrective actions are implemented in accordance with the corrective actions program. Acceptance criteria are specifically stated in the plant procedures that govern each test or inspection.

18.3.2 FLOW ACCELERATED CORROSION PROGRAM

The FAC program is a condition monitoring program designed to monitor pipe component wear in those systems that have been determined to be susceptible to FAC related loss of material. The objective of the program is to ensure that the damage caused by flow-accelerated corrosion will not cause components failures. This objective is accomplished by predicting the rate of degradation of components and taking corrective actions once the degradation is detected.

FAC is different from many other corrosion processes in that corrosion rates may be generally predicted.

Components identified by the plant predictive FAC model are periodically examined based on the recommendations of the EPRI NSAC-202L[41] since they meet all of the screening criteria contained within EPRI NSAC 202L for systems potentially susceptible to FAC.

The current term FAC program has been enhanced for the period of extended operation to include some components that do not meet all of the FAC criteria within EPRI NSAC 202L or component that are excluded from the plant predictive FAC model due to size.

The basis for the FAC program is EPRI NSAC-202L and the associated CHECWORKS™[42] computer code, which is used to create a plant predictive CHECWORKS™ FAC model. This plant predictive FAC model accounts for system conditions relevant to FAC such as pH, dissolved oxygen content, fluid (steam) quality, temperature, pipeline velocity, component geometry, and material of construction.

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. Program Scope

The FAC program will examine portions of the following systems within the scope of license renewal.

- Nuclear Boiler
- High Pressure Coolant Injection Steam Supply Drains
- Reactor Core Injection Coolant Steam Supply Drains
- Unit 2 portions of the radioactive decay holdup volume (main steam, main steam line drains, condensate drains and condenser shell)

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The FAC program provides for visual and volumetric inspections intended to detect loss of material by monitoring component wall thickness.

D. Detection of Aging Effects

FAC program inspections are implemented to detect loss of material via radiographic (RT), ultrasonic (UT), and visual inspections.

E. Monitoring and Trending

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with FAC program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the FAC program is noted and corrective actions will be implemented in accordance with the corrective action program.

18.3.3 PROTECTIVE COATINGS PROGRAM

The Plant Hatch protective coatings program (PCP) provides a means of preventing or minimizing loss of material that would otherwise result from contact of the base material with a corrosive environment. The PCP is a mitigation and condition monitoring program designed to provide base metal aging management through surface application, maintenance, and inspection of protective coatings on selected components and structures.

Coating Service Level I are those coating systems applied inside the primary containment where coating failure could adversely affect the operation of post-accident fluid systems and, thereby, impair safe shutdown of the plant.

Coating Service Level II are those coating systems, which are applied to systems, structures and components whose operation is essential to the attainment of the intended normal operating performance. The function of service level II coatings is to provide corrosion protection and decontaminability.

Coating Service Level III are those coating systems applied outside of primary containment, but which in the event of failure could adversely affect the orderly and safe shutdown of the plant.

A. Program Scope

The PCP provides specifications for coatings applied to structures and components within the scope of license renewal. The PCP includes specific inspection techniques and frequencies for Service Level I coatings (which include non-immersion coatings applied to the suppression chamber and drywell airspace and immersion coatings applied to the suppression chamber interior below the normal water level). The current term PCP has been enhanced for the renewal term to provide inspection techniques and frequencies for certain accessible non-service level I coatings. These requirements apply to external surfaces of carbon steel commodities outside of primary containment and within the scope of license renewal that are expected to experience significant atmospheric corrosion.

The PCP has also been enhanced to provide for inspection and documentation of the condition of normally inaccessible (underground or embedded) carbon steel components within the scope of license renewal, whenever these components are exposed or uncovered.

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.

B. Preventive or Mitigative Actions

Proper application of coatings limits, loss of material by preventing direct contact between susceptible base materials and environmental conditions conducive to corrosion.

C. Parameters Inspected or Monitored

Periodic inspection of components is conducted in order to identify areas of degraded coatings and associated corrosion of base metals, which may indicate a loss of material

D. Detection of Aging Effects

Detection of degraded coatings and associated corrosion of base metals is accomplished primarily through visual inspection techniques. For surfaces determined to be suspect, dry film thickness, adhesion, and continuity tests may also be performed.

E. Monitoring and Trending

Service level I coatings are inspected at set intervals. A baseline inspection of non-service level I coated components within the scope of license renewal will be performed. Coated components are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with site procedures.

F. Acceptance Criteria

Any significant degradation of structural components that is observed during the visual inspection activities is noted and corrective actions implemented in accordance with the corrective actions program. Acceptance criteria are specifically stated in the PCP and the implementing procedures.

Specific acceptance criteria for the protective coatings program are based on multiple codes and standards. These include but are not limited to ANSI N5.12 – 1972[43], ANSI N101.2 – 1972[44], ASTM, Section 6, Volume 06.02[45], AWWA C203-1966[46], AWWA C209-1995[47].

Coatings application is performed in accordance with vendor recommendations and industry practices.

18.3.4 EQUIPMENT AND PIPING INSULATION PROGRAM

Equipment and piping insulation performance may be degraded if the insulation or jacketing is damaged. The equipment and piping insulation monitoring program (EPIM) is a condition monitoring program designed to detect cracking, loss of material, and changes in material properties in insulation through periodic inspection of specific passive component insulation. The current term program has been enhanced for the period of extended operation to include insulation on selected systems located inside buildings.

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

A. Program Scope

The equipment and piping insulation monitoring program inspects insulation on portions of systems within the scope of license renewal. These systems are:

- standby liquid control
- residual heat removal (RHR) and RHR service water
- core spray
- high pressure coolant injection
- reactor core isolation cooling
- condensate transfer and storage (exposed piping at CST)
- plant service water
- fire protection (exposed piping at fire pump house)

B. Preventive or Mitigative Actions

EPIM program implementing procedures contain precautions that mitigate insulation damage by limiting climbing on pipe insulation. Damage is further mitigated by implementing procedures that provide specific instructions for removal, storage and installation of thermal and reflective insulation. Preventing the damage assures that changes in material properties, cracking, and loss of material are also prevented.

C. Parameters Inspected or Monitored

The equipment and piping insulation monitoring program provides for periodic visual inspection. The visual inspection identifies changes in material properties of the insulation. Aluminum and galvanized steel insulation jackets and their binders are inspected for cracking and loss of material.

D. Detection of Aging Effects

Visual inspection of the insulation and insulation jackets is performed to identify degradation which may indicate the aging effects of changes in material properties, loss of material, or cracking.

E. Monitoring and Trending

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with EPIM program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of a change in material properties, cracking, or loss of material will be evaluated by engineering. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the EPIM program is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.3.5 STRUCTURAL MONITORING PROGRAM

The structural monitoring program (SMP)[48] provides a condition monitoring and appraisal process for structures and components within the scope of the Maintenance Rule (10 CFR 50.65)[49] and the License Renewal Rule (10 CFR 54)[25]. The SMP inspection process assesses the overall conditions of the buildings and structures, and identifies any ongoing degradation. The SMP manages loss of material, cracking and changes in material properties (including loss of adhesion).

A. Program Scope

The enhanced SMP monitors those portions of the following structures, components and commodities that are within the scope of license renewal. The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program[50].

- reactor buildings
- turbine buildings
- intake structure
- off gas stack
- EDG building
- control building
- condensate storage tank foundations and concrete walls surrounding the tanks
- PSW valve pits
- diesel generator fuel oil storage tanks
- nitrogen storage tank foundations
- foundations for the two fire protection water storage tanks
- foundations for the two fire protection diesel pump fuel tanks
- foundation for the fire pump house
- underground concrete duct runs and pull boxes between Class I structures
- Category I and II/I piping supports and tube tray supports
- Category I HVAC duct supports
- Category I and II/I cable trays and supports
- Category I and II/I conduits and supports
- Category I control room panels, racks and supports
- Category I auxiliary panels, racks and supports
- sealants in the joints between the reactor building exterior precast siding panels
- reactor building tornado vents
- reactor building penetrations

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The SMP is a condition monitoring program that utilizes visual inspections to identify aging effects prior to any loss of intended function. Concrete structures are inspected for cracks, leaching, spalling and corrosion staining, as evidence of loss of material and cracking. Steel components are inspected for general and localized corrosion as evidence of loss of material. Panel joints and seals are inspected for evidence of loss of adhesion and changes in material properties. The acrylic domes of the tornado vents are inspected for cracks. Block walls are inspected for cracks.

D. Detection of Aging Effects

Structural condition is assessed through a visual inspection. Inspections include those structures normally accessible, as well as those below ground or embedded. When inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Qualified personnel, using detailed checklists, inspection tools and preparations perform the inspections. Noted degradation may be documented utilizing digital photography.

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. The frequencies of the inspections are defined in the SMP document[48] and the implementing procedures.

As an additional measure of detection, the standby gas treatment system flow test can detect gross changes in in-leakage that may be indicative of age-related degradation.[51]

E. Monitoring and Trending

Initial inspections (baseline) were conducted to facilitate condition trending. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with SMP implementing procedures.

F. Acceptance Criteria

Acceptance criteria for the inspection and criteria for categorizing the overall structure and component conditions (i.e., acceptable, acceptable with deficiency, or unacceptable) are provided in the procedure. The acceptance criteria are consistent with the recommended criteria in ACI-349.3R-1996[52], but also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The results of the inspections are evaluated in accordance with the guidance given in ACI-349.3R-1996[52] and NRC Regulatory Guide 1.160[53].

The structures will be inspected for the following conditions based on the acceptance criteria stated in the SMP document[48]. Any significant degradation of structural components observed during the visual inspections is noted and corrective actions implemented in accordance with corrective actions program. Acceptance criteria are specifically stated in the SMP and the implementing procedures.

Table 18.3.1-1 - Activities Performed to Manage Aging Effects for Fire Protection System Components

Activity	Method	Parameter
Cable tray enclosure inspection	Visual inspection	Condition - degradation
CO2 systems component inspection	Visual inspection	Condition - corrosion / degradation
CO2 systems performance test	Performance test	Flow
Exterior coatings inspection	Visual inspection	See Protective Coatings Program
Fire damper functional test	Performance test / Visual inspection	Observe full closure and no visible openings
Fire damper inspection	Visual inspection	Condition - corrosion / degradation
Fire diesel fuel oil tank level	Visual inspection	Fuel oil level
Fire hydrant flow check	Performance testing	Flow
Fire penetration seal inspection	Visual inspection	Condition - degradation
Fire Water Tank internal and external inspection	Visual inspection	Condition – corrosion, size and depth of pits
Fire Water Tank volume	Visual inspection	Water level
Flow test of water mains	Performance test	Pressure drop
Fuel oil storage tank sampling	Visual inspection / lab analysis	Presence of water, sediment, and other contaminants
Fuel oil system leak inspection	Visual inspection	Fuel oil leaks
Fuel oil tank internal inspection	Visual inspection	Condition - corrosion / degradation
Hose station inspection	Visual inspection	Condition - corrosion / degradation
Hose station valve cycling	Performance testing	Flow
Open head/deluge spray nozzle air flow test	Performance test	Flow
Sprinkler heads and nozzles inspection	Visual inspection	Condition – corrosion / degradation
Sprinkler system header flow activity	Performance test	Flow
Sprinkler system trip test	Performance test	Flow
Start and run each fire pump	Performance test	Flow, developed head
Start and run fire diesels	Performance test	Fuel oil leaks
Strainer inspection	Visual inspection	Condition - corrosion / degradation
System isolation valve cycling	Performance test / Visual inspection	Observe full valve position change

18.4 NEW PROGRAMS/ACTIVITIES

18.4.1 GALVANIC SUSCEPTIBILITY INSPECTIONS

The galvanic susceptibility inspections will provide for condition monitoring via one-time inspections that will provide objective evidence that loss of material due to galvanic corrosion is being managed for specific components within the scope of license renewal.

A. Program Scope

Galvanic susceptibility inspections will examine an initial sample set of raw water carbon to stainless steel connections that are within the scope of license renewal. The inspected points will be the locations that are expected to have the greatest potential for galvanic coupling. Based on the results of the sample inspections, the sample set may be expanded to include galvanic couples associated with components in other environments. Systems include:

- nuclear boiler
- control rod drive
- residual heat removal and residual heat removal service water
- core spray
- high pressure coolant injection
- reactor core isolation cooling
- main condenser system
- plant service water
- emergency diesel generator
- primary containment
- containment atmospheric control
- traveling water screens

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The galvanic susceptibility inspections provide for visual and volumetric inspections intended to detect loss of material due to galvanic corrosion. Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible.

The sample size of each examination method will be a function of the sample locations and component geometry.

D. Detection of Aging Effects

Inspections will be performed using one or more methods. These may include visual inspections, ultrasonic thickness determinations, radiographic testing, depth gauges, and pipe removal and analysis. Visual inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the GSI is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.2 TREATED WATER SYSTEMS PIPING INSPECTIONS

The treated water systems piping inspections will be one time condition monitoring examinations intended to prove that existing chemistry control is managing loss of material and cracking in piping that is not examined under another inspection program.

A. Program Scope

Scope of the program includes the specific structure, component, or commodity for the identified aging effect. Specific commodities include, but are not limited to, carbon and stainless steel piping, tubing, valve bodies, pump casings, tanks, accumulators and strainer bodies.

Treated water systems piping inspections will examine a sample population of carbon and stainless steel tubing and piping in the treated water systems within the scope of license renewal. The results of the sample population examinations will be evaluated, and subsequent examinations will be conducted where evaluation results warrant.

Systems included are:

- nuclear boiler
- reactor recirculation
- control rod drive
- standby liquid control
- residual heat remove
- core spray
- high pressure coolant injection
- reactor core injection coolant
- main turbine auxiliaries

- portions of the radioactive decay holdup volume (main steam, main steam lines condensate drains and condenser shell) in Unit 2 only
- condensate storage and transfer
- reactor building component cooling water
- plant component cooling water (Unit 2 only)
- emergency diesel generator auxiliaries
- primary containment
- containment atmospheric control system

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The treated water systems piping inspection provide for visual and volumetric inspections intended to detect loss of material and cracking.

These one-time inspections will focus Class 1 and Non-Class 1 carbon and stainless steel components within the reactor water, torus water, demineralized water, closed cooling water, and borated water environments.

Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible.

D. Detection of Aging Effects

Inspections of the sample set will be conducted using the best available examination method for the inspected component. Visual inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210. Alternately, volumetric inspections may be used.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of corrosion will be evaluated by further engineering. When appropriate, engineering evaluations will be based upon the design code record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by treated water systems piping inspections is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.3 GAS SYSTEMS COMPONENTS INPSECTIONS

The gas systems component inspections (GSCI) will be a set of one-time condition monitoring inspections that provide objective evidence that age-related degradation is not inhibiting component function in gas-bearing in-scope systems and components. The aging effects that GSCI are intended to manage are loss of material, cracking, and material property changes.

A. Program Scope

The GSCI are applied to a sample set drawn from a population of components exposed to humid and wetted gas in the following systems:

- nuclear boiler (safety relief valve tailpipes to the torus)
- control rod drive
- residual heat removal
- high pressure coolant injection
- reactor core isolation cooling
- sampling
- starting air and engine exhaust subsystems of the emergency diesel generators
- primary containment (including the drain lines for the drywell sump discharge)
- reactor building HVAC
- standby gas treatment
- primary containment purge and inerting
- post LOCA hydrogen recombiners
- outside structure HVAC
- fire protection
- fuel oil (fuel oil storage tank vapor spaces)
- control building HVAC (including gaskets)

The sample population will focus on those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation.

The Unit 1 and common inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The GSCI provide for visual and volumetric inspections intended to detect loss of material, cracking, and material property changes.

D. Detection of Aging Effects

The GSCI use visual inspection techniques (similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210). Alternatively, volumetric inspections may be used.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with these inspections.

F. Acceptance Criteria

Any unacceptable indication of loss of material or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the GSCI is noted and corrective actions will be implemented in accordance with the existing corrective actions program.

18.4.4 CONDENSATE STORAGE TANK INSPECTIONS

The CST Inspection will be a one-time condition monitoring inspection of the internal surfaces of each CST designed to provide objective evidence that no loss of material is occurring. This inspection is intended to validate the adequacy of current demineralized water chemistry controls to manage corrosion.

A. Program Scope

The CST inspection activities will inspect only those CST components, within the scope of license renewal, required to assure the availability of 100,000 gallons of water for the high pressure coolant injection and reactor core injection coolant systems.

The Unit 1 inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. The Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The condensate storage tank inspection provides for visual inspection intended to detect loss of material. These inspections will focus on selected areas associated with the standpipes, associated supports and nozzles.

Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible.

D. Detection of Aging Effects

The CST Inspection will utilize visual inspection techniques similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the condensate storage tank inspection is noted and corrective actions will be implemented in accordance with the corrective action program.

18.4.5 PASSIVE COMPONENTS INSPECTION ACTIVITIES

The passive components inspection activities (PCIA) are a set of on-going condition monitoring inspections designed to confirm that age-related degradation is not inhibiting the component functions of systems and components within the scope of license renewal. The PCIA manages the aging effects of loss of material, cracking, and change in material properties.

A. Program Scope

The PCIA are applied to a sample set of components drawn from a population of components, in the scope of license renewal, in the following systems:

- nuclear boiler (safety relief valve tailpipes to the torus)
- control rod drive
- residual heat removal
- high pressure coolant injection
- reactor core isolation cooling
- starting air and engine exhaust subsystems of the emergency diesel generators
- primary containment (including the drain lines for the drywell sump discharge)
- reactor building HVAC
- standby gas treatment
- primary containment purge and inerting
- post LOCA hydrogen recombiners
- outside structure HVAC
- fire protection
- fuel oil (fuel oil storage tank vapor spaces)
- control building HVAC (including gaskets)

PCIA is based on availability, not population. As such, population, frequency, and sample size are not pre-determined. The preferred inspection sites will be those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with these activities.

C. Parameters Inspected or Monitored

Visual inspections in the PCIA verify material condition by checking for the presence of corrosion and cracking, so that engineering can make an evaluation of the impact of loss of material and cracking. For gaskets, the PCIA will visually inspect for the presence of cracks or material degradation to determine if a change in material properties of a loss of material has occurred.

D. Detection of Aging Effects

The PCIA are condition monitoring activities that utilize visual inspections and volumetric inspections to identify aging effects prior to any loss of intended function. The PCIA will develop a baseline examination of a sample population of the in-scope components, as they become available due to normal maintenance activities. The PCIA will use visual inspection techniques (similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210). Where possible and practical, accessible components may be inspected for stress corrosion cracking using surface or volumetric examination.

E. Monitoring and Trending

The PCIA collects, reports, and trends age-related data. Inspection results are maintained in plant records. Engineering personnel track and trend results in accordance with PCIA implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material, change in material properties, or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components inspected by the PCIA is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.4.6 RHR HEAT EXCHANGER AUGMENTED INSPECTION AND TESTING PROGRAM

The RHR heat exchanger augmented inspection and testing program is a condition monitoring program that manages aging of the RHR heat exchangers. The aging effects managed are loss of material, flow blockage, cracking, and loss of thermal performance.

The program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13[18]. SNC used the guidance of SAND 93-7070[54], as supplemented by reviews of current industry experience and practice, as the basis for this program.

A. Program Scope

The subject program will inspect, test, and maintain passive components of the RHR heat exchangers that are within the scope of the license renewal.

B. Preventive or Mitigative Actions

The RHR heat exchanger augmented inspection and testing program requires that heat exchanger tubes and channel interior be cleaned on a periodic basis. This cleaning of the heat exchanger tubes and channel head mitigates flow blockage and loss of thermal performance.

C. Parameters Inspected or Monitored

The RHR heat exchanger augmented inspection and testing program provides for visual inspections, pressure testing, and eddy current testing intended to detect loss of material and flow blockage. Parameters inspected or monitored are the following: loss of material, flow area reduction due to fouling, and cracking.

D. Detection of Aging Effects

RHR heat exchanger augmented inspection and testing program is performed at prescribed frequencies in the implementing procedures to detect the identified aging effects of the heat exchanger passive components.

Visual inspection of channel side (including partition plate and tube sheet) and tube interior is performed This activity detects loss of material, flow blockage, and cracking.

The current term activities have been augmented for the period of extended operation by addition of the following tests and inspections:

Eddy Current Testing is performed periodically and whenever leaks are suspected. This activity detects loss of material and cracking.

The shell side of the tube sheets, shell internals, and impingement plates are visually inspected periodically, where accessible. This activity detects loss of material, flow blockage (fouling), and cracking.

Tube and tube sheet leak testing is performed whenever leaks are suspected. This activity detects leaks due to cracking and loss of material.

These augmentations will be fully implemented no later than midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

E. Monitoring and Trending

Inspection and testing results are maintained in plant records. Engineering personnel track and trend results in accordance with implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of loss of material is evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections are performed. Any significant degradation of components inspected by the RHR heat exchanger augmented inspection and testing program is noted and corrective actions are implemented in accordance with the existing corrective actions program.

18.4.7 TORUS SUBMERGED COMPONENTS INSPECTION PROGRAM

The torus submerged components inspection program (TSCIP) is a condition monitoring activity designed to monitor torus submerged components for loss of material and cracking. The objective of the program is to assure that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of suppression pool chemistry controls to manage aging effects for a variety of uncoated structures and components that are exposed to the suppression pool environment.

A. Program Scope

The TSCIP will examine a sample set of 10 percent of the uncoated components within the scope of license renewal and located in the torus. This sample will be biased towards the areas most likely to exhibit corrosion related degradation.

Portions of the following systems are within the scope of the TSCIP:

- safety relief valve tailpipe
- residual heat removal strainers
- core spray strainers
- high pressure coolant injection suction strainers and turbine exhaust
- reactor core isolation cooling suction strainers and turbine exhaust
- primary containment purge and inerting (vacuum relief piping)

The TSCIP will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The TSCIP provides for visual inspections intended to detect loss of material and cracking in uncoated components and structures submerged within the suppression pool and in the vapor space directly above the suppression pool.

D. Detection of Aging Effects

The TSCIP will utilize visual inspection techniques similar to that described for VT-1 in ASME Section XI[6], paragraph IWA-2210.

E. Monitoring and Trending

There are no trending or monitoring attributes associated with this activity.

F. Acceptance Criteria

Any unacceptable indication of loss of material or cracking will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, based upon the results of the initial inspections, inspections of additional locations within the torus will be performed. Corrective actions will be implemented in accordance with the corrective actions program.

18.4.8 INSULATED CABLES AND CONNECTIONS PROGRAM

The insulated cables and connections program is a condition monitoring program designed to confirm that age-related degradation (change in material properties) is not inhibiting component function of insulated cables and connectors.

A. Program Scope

The insulated cables and connections program is a sampling program and includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the primary containment structure, reactor building, radwaste building, diesel generator building, turbine building, control building, intake structure, and main stack, which could be subject to applicable aging effects from heat or radiation. This progam does not include cables and connections that are in the Environmental Qualification program. Based on the results of the sample inspections, the sample set may be expanded to include additional components. The initial Unit 1 and common inspections will be performed by midnight August 6, 2014. The initial Unit 2 inspections will be performed by midnight June 13, 2018.

B. Preventive or Mitigative Actions

There are no preventive or mitigative attributes associated with this program.

C. Parameters Inspected or Monitored

The insulated cables and connections program provides for visual inspections and testing intended to detect aging degradation. Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat or radiation.

D. Detection of Aging Effects

Accessible insulated cables and connections will be inspected periodically. Inaccessible cables and connections will be tested periodically.

E. Monitoring and Trending

Inspection and test results are maintained in plant records. Engineering personnel track and trend results in accordance with insulated cables and connections program implementing procedures.

F. Acceptance Criteria

Any unacceptable indication of change in material properties will be evaluated by engineering. If warranted, additional inspections or tests will be performed. Any significant degradation of components inspected by the insulated cables and connections program is noted and corrective actions will be implemented in accordance with the corrective actions program.

18.5 TIME LIMITED AGING ANALYSES CREDITED FOR LICENSE RENEWAL

18.5.1 TIME LIMITED AGING ANALYSES

Title 10 CFR Part 54 (the License Renewal Rule, or 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.

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.[55]

Given those six criteria, many calculations and analyses qualified as TLAAs. A summary listing of those calculations and analyses is shown in Table 18.5-1.

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.[56]

With the exceptions of two areas further discussed below, all of the items in Table 18.5-1 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.

18.5.1.1 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 (see Section 18.2.12). Additional details of this program are described in sections 4.2.5 and 5.4.6 of the Unit 1 and 2 Final Safety Analysis Reports, respectively.

18.5.1.2 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, are managed by the 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 18.5-1 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.

18.6 REFERENCES

1. TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines".

2. TR-107396, EPRI "Closed Cooling Water Chemistry Guidelines".

3. Generic Letter 89-13 with Supplement 1 "Service Water System Problems Affecting Safety-Related Equipment," 1990.

4. State of GA Department of Natural Resources Environmental Protection Division Permit No. GA0004120, "Plant Hatch NPDES Permit", Effective September 15, 1997.

5. 10 CFR 50, Appendix B "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants"

6. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

7. 10 CFR 50.55a, Codes and Standards

8. ANSI B30.2-1976, Overhead and Gantry Cranes.

9. NUREG-0612, Control of Heavy Loads of Nuclear Power Plants.

10. ANSI B30.9-1971, Slings.

11. ANSI/ASME B 30.10-1982, Hooks (Revision of ANSI B30.10-1975).

12. ANSI N14.6-1978, Special Lifting devices for shipping containers weighing 10,000 lbs. (4500 kg) or more for nuclear materials.

13. ASME Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessel."

14. ASME Boiler and Pressure Vessel Code, Section II, "Specification for Carbon Steel Externally Threaded Standard Fasteners."

15. ASTM Standards, Section 15, Volume 15.08, "Fasteners."

16. ASME B31.1, "Power Piping."

17. ASME Boiler and Pressure Vessel Code, Section III, "Rules of Construction for Nuclear Power Plant Components."

18. NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment," July 18, 1989.

19. 10 CFR 50, Appendix J "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors".

20. Regulatory Guide 1.163 "Performance-based Containment Leak-Test Program".

21. NEI 94-01 "Industry Guideline for Implementing Performance-based Option of 10 CFR Part 50, Appendix J".

22. ANSI/ANS 56.8-1994 "American National Standard for Containment System Leakage Testing Requirements".

23. Bechtel Topical Report BN-TOP-1 "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants".

24. Edwin I. Hatch Nuclear Plant Technical Specifications, Units 1 and 2, Section 3.6.

25. 10 CFR 54, License Renewal Rule.

26. NUREG 0619 – "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking", U.S. NRC, November 1980.

27. BWRVIP-18 – BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines.

28. BWRVIP-26 – BWR Top Guide Inspection and Flaw Evaluation Guidelines.

29. BWRVIP-27 – BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines.

30. BWRVIP-38 – BWR Shroud Support Inspection and Flaw Evaluation Guidelines.

31. BWRVIP-41 – BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines.

32. BWRVIP-47 – BWRVIP Lower Plenum Inspection and Flaw Evaluation Guidelines.

33. BWRVIP-48 – Vessel ID Attachment Weld Inspection and Evaluation Guidelines.

34. BWRVIP-74 – BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines.

35. BWRVIP-76 – Core Shroud Inspection and Evaluation Guidelines.

36. 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements.

37. BWRVIP-78, BWR Integrated Surveillance Program Plan.

38. ASTM E185, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

39. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials"

40. 10 CFR 50, Appendix G, Fracture Toughness Requirements.

41. EPRI NSAC-202L "Recommendations for an Effective Flow-Accelerated Corrosion Program, November 1993.

42. EPRI CHECKWORKS Computer Program, Version 1.0 C.

43. ANSI N5.12 – 1972 "Protective Coatings (Paints) for the Nuclear Industry."

44. ANSI N101.2 – 1972 "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities."

45. ASTM Section 6, Vol. 6.02 "Paints-Products and Applications; Protective Coatings; Pipeline Coatings."

46. American Water Works Association (AWWA) C203 – 1966 "Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines – Enamel and Tape – Hot Applied."

47. AWWA C209 – 1995 "Cold Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines," 2nd Ed.

48. A-44985, Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant, Units 1 and 2.

49. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

50. Westinghouse Owner's Group Life Cycle Management / License Renewal Program, Altran Corporation / Altran Materials Engineering.

51. Unit 1 and Unit 2 Plant Hatch Technical Specifications, SR 3.6.4.1.4.

52. ACI Committee 349, Report ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."

53. NRC Regulatory Guide 1.160, Rev 2 "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

54. SAND 93-7070. UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers," July 1994.

55. 10 CFR 54.3, "Definitions."

56. 10 CFR 54.21.(c).1, "Contents of the Application – Technical Information."

57. NFPA 25, National Fire Protection Association Standard.

ENCLOSURE 3

REVISED APPENDIX B

SECTIONS 2.1 AND 2.5

IN RESPONSE TO DRAFT SER

OPEN ITEMS 3.1.18-1 (b)

AND 3.6.3.1-1

REGARDING THE PLANT HATCH

LICENSE RENEWAL APPLICATION

June 4, 2001

B.2 ENHANCED PROGRAMS AND ACTIVITIES

B.2.1 Fire Protection Activities

Fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. Fire protection activities provide assurance that loss of material, cracking, flow blockage, and changes in material properties will not prevent the performance of necessary safe shutdown functions.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Plant Hatch fire protection activities credited for license renewal include those portions of fire protection systems identified in the Fire Hazards Analysis (FHA) as forming part of the CLB. These include passive long-lived components in water based and gaseous fire suppression systems, the fire pump diesel fuel oil supply system (tanks and piping), fire doors, fire penetration seals, fire dampers, and cable tray enclosures. All of these components are part of the fire protection (X43) system.

The current term fire protection activities have been enhanced for the period of extended operation to include periodic inspection of water suppression system strainers and sprinkler heads. These enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. There are no preventive or mitigate attributes associated with the condition and performance monitoring elements of this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Surveillance and inspection of in-scope fire protection systems and components are performed in accordance with the requirements and frequencies of the applicable portions of both Appendix B of the FHA and plant procedures that cover in-scope components.

For water based fire protection systems, the fire protection activities include the following tests and inspections. Flushing of loop headers is performed at least once per 18 months to remove corrosion product buildup and ensure adequate flow through the system. Flow testing of water based fire suppression mains is performed at least once per 3 years and system frictional pressure drop is measured. Fire Water Tank external surfaces are inspected annually and external and internal surfaces are inspected once per 5 years for corrosion and general condition of the protective coating. Sizes and depth of pits are recorded and interior surfaces are cleaned as required to facilitate inspection. The contained water supply volume in these tanks is confirmed at least once per 31 days. Each fire pump is started at least once per 31 days and run for at least 30 minutes. Each diesel driven pump is started at least once per 18 months during shutdown and run for at least 60 minutes. The capacity and developed head of each fire pump is confirmed at least once per 12 months. FHA Appendix B sprinkler heads and nozzles are visually inspected for degradation at least once per 18 months and FHA Appendix B open head / deluge spray nozzles are air flow tested at least once per 3 years. A sprinkler system header flow activity is conducted quarterly to verify unobstructed flow. A sprinkler system trip test is conducted for FHA Appendix B sprinkler systems at least once per 6 months to verify operability. FHA Appendix B Hose stations are inspected at least once per 31 days and hose station valves are partially opened to demonstrate unobstructed flow at least once per 2 years. All other in-scope hose stations are inspected at least once every quarter and hose station valves are partially opened to demonstrate unobstructed flow at least once every 5 years. Water suppression system strainer internals are inspected at least once per 2 years. In-scope fire hydrants are flow checked at least once per 12 months. Each testable isolation valve in the water suppression system flow path is cycled at least once per 12 months and each valve that is not testable during plant operation is cycled at least once per 18 months. All in-scope, above ground piping and equipment coatings or paint are inspected per the industry guidance of the Protective Coatings Program.

For the fire protection pump diesel fuel oil supply system, the fire protection activities include the following tests and inspections. Each fire diesel fuel oil storage tank level is confirmed at least once per 31 days. The fuel oil system is inspected for leaks at least once per 31 days. Each fuel oil storage tank is sampled for water, sediment, and other contaminants at least once per 92 days. The fuel oil storage tanks are drained and inspected for corrosion, based on sampling and as deemed necessary by Plant Maintenance Engineering. Each fire diesel is started and operated at least once per 31 days and at least once per 18 months during shutdown to demonstrate, among other things, operability of fuel oil supply system. All in-scope, above ground piping and equipment coatings or paint are inspected per the industry guidance reflected in the Protective Coatings Program.

For compressed gas based fire suppression systems, the fire protection activities include the following tests and inspections. All CO_2 system components are visually inspected at least once every 62 days and performance tested at least once per 12 months. The periodic visual inspections include CO_2 storage tank pressure and level, tank insulation condition, and pressure boundary leaks. The annual performance test includes the discharge of a small volume of CO_2 through system nozzles within a specified time period. All in-scope, above ground CO_2 piping and equipment coatings or paint are inspected per the industry guidance of the Protective Coatings Program.

For fire penetration seals, the fire protection activities include the following inspections. A minimum 10% sample of each type of penetration seal is visually inspected at least once per 18 months and samples are selected such that each penetration seal is inspected at least once per 15 years.

For cable tray enclosures, the fire protection activities include the following inspections. In-scope cable tray enclosures are visually inspected at least once per 18 months.

For fire doors, the fire protection activities include the following tests and inspections. In-scope fire doors are visually inspected at least once per 6 months and functionally tested at least once per 18 months. Exterior coatings or paint are inspected per the industry guidance reflected in the Protective Coatings Program.

For fire dampers, the fire protection activities include the following tests and inspections. In-scope fire dampers are visually inspected and functionally tested at least once per 18 months. Exterior coatings or paint are inspected per the industry guidance of the Protective Coatings Program.

An inspection called "Sprinkler Head Inspections" will be performed periodically for closed sprinkler heads in the scope of license renewal. The first inspection will take place after 50 years of service and subsequent inspections at 10-year intervals thereafter. Consistent with the guidance in NFPA-25, a random sampling of each type of sprinkler head in the scope of license renewal will be submitted to a recognized laboratory for testing. Based on the results, corrective actions will be accomplished, if required, to assure continued sprinkler head functionality during the period of extended operation.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Detection of flow blockage, loss of material, cracking, and changes in material properties are accomplished directly by visual examinations of component surfaces and laboratory testing and indirectly through the use of flow or functional testing.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Inspection and performance test results are maintained in plant records. Engineering personnel track and trend results in accordance with site procedures.

Acceptance Criteria

(Acceptance criteria are included.)

Any significant degradation of fire protection system components observed during visual inspections or performance testing activities are noted and corrective actions implemented in accordance with the Plant Hatch corrective actions program. Acceptance criteria are specifically stated in the plant procedures that govern each test or inspection.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

Based on a review of five years of plant deficiency card data, deficiencies in water based fire suppression systems include deterioration of coatings within the fire water storage tank and fouling of lines due to corrosion product buildup. These deficiencies were identified during testing and inspection required by the Fire Protection Activities or during normal walkdowns. 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.

A similar plant deficiency card review for other fire protection system components, identified deficiencies concerning minor degradation of fire penetration seals and exterior corrosion on gaseous fire suppression system piping. None of these deficiencies were determined to be significant since no loss of intended function occurred.

References

1. *Edwin I. Hatch Nuclear Plant, Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.*
2. *NFPA 25 - National Fire Protection Association Standard*

B.2.5 Structural Monitoring Program

The Plant Hatch SMP provides a stepped, condition monitoring and appraisal process for structures and components within the scope of the Maintenance Rule (10 CFR 50.65) and the License Renewal Rule (10 CFR 54). The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Structural Monitoring Program monitors the following structures, components and commodities. This list reflects a recent revision to the SMP to address program enhancements made as a result of license renewal.

- Switchyard (not required for License Renewal)
- Reactor Buildings
- Turbine Buildings
- Intake Structure
- Off Gas Stack
- EDG Building
- Control Building
- Waste Gas Building (not required for License Renewal)
- Condensate Storage Tank foundations and concrete walls surrounding the tanks
- PSW Valve Pits
- Diesel Generator Fuel Oil Storage Tanks
- Nitrogen Storage Tank Foundations
- Foundations for the two fire protection water storage tanks
- Foundations for the two fire protection diesel pump tanks
- Foundations for the fire pump house
- Underground concrete duct runs and pull boxes between Class I structures
- Category I and II/I piping supports and tube tray supports
- Category I HVAC duct supports
- Category I and II/I cable trays and supports
- Category I and II/I conduits and supports
- Category I control room panels, racks and supports
- Category I auxiliary panels, racks and supports
- Sealants in the joints between the reactor building exterior precast siding panels
- Reactor Building tornado vents
- Reactor Building penetrations

In addition, the SMP monitors secondary containment leakage characteristics.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The SMP is a condition monitoring program that utilizes visual inspections to identify aging effects prior to any loss of intended function. As such, there are no preventive or mitigate attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Concrete structures are inspected for cracking and spalling. Masonry block walls are inspected for cracking. Steel structures and components are inspected for corrosion. Panel joints seals and sealants are inspected for loss of adhesion, material property changes and cracking. The acrylic domes on the tornado vents will be inspected for cracking. Secondary containment leakage characteristics are verified per SR 3.6.4.1.4 of the Plant Hatch Technical Specifications (Ref. 7).

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The SMP inspection process assesses the ongoing, overall conditions of the buildings and structures, and identifies any ongoing degradation. Structure condition is assessed through a visual inspection. Inspections 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. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

The inspections are performed by qualified personnel, using detailed checklists, inspection tools and preparations. All inspection results are documented in checklists and noted degradation may be documented utilizing digital photography.

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. As a result of the baseline inspections a five-year inspection frequency was established for the structures monitored. This frequency will continue unless the conditions, environment, or noted degradation warrant a change. At this time, the plant has elected to inspect the intake structure every operating cycle due to humid environmental conditions. However, based on the results of future intake structure inspections, the plant may elect to go back to a five-year frequency. For areas of the subject buildings and structures that are inaccessible due to physical obstruction, and below grade, embedded or buried components, inspections are performed whenever these areas are excavated, exposed or modified.

As an additional measure of detection, the standby gas treatment system flow test can detect gross changes in in-leakage (per Ref. 7) that may be indicative of age-related degradation.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Initial inspections (baseline) were conducted to facilitate condition trending. Structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding.

The reactor building (including spent fuel areas), control building, turbine building, offgas stack, diesel building, condensate storage building, plant service water valve pits, diesel fuel storage tanks, and nitrogen storage tanks will be inspected on a 5 cycle interval. Certain areas within the reactor building will be inspected every other cycle. These include the drywell, torus (inside), and overhead cranes. Secondary containment leakage characteristics will be verified at a frequency specified by Ref. 7.

Acceptance Criteria

(Acceptance criteria are included.)

Acceptance criteria for the inspection and criteria for categorizing the overall structure and component conditions (i.e., acceptable, acceptable with deficiency, or unacceptable) are provided in the procedure. The acceptance criteria are consistent with the recommended criteria in ACI-349.3R-1996, but also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The results of the inspections are evaluated in accordance with the guidance given in NEI-96-03 and NRC Regulatory Guide 1.160. The results of SMP inspections are forwarded to the Maintenance Rule Coordinator who determines if any condition reports should be initiated.

The following selected acceptance criteria are detailed in the Structural Monitoring Program for acceptability of the components:

<u>Concrete Components</u>

Spalls less than 3/4" in depth and 8" in dimension

Passive cracks less than 0.040" in width, measured below any surface enhanced widening ("passive cracks" are those with no evidence of recent growth and absence of other degradation mechanisms at the crack). For cracks greater than or equal to 0.040" in width, the length of the crack will be measured / estimated and documented in the database.

<u>Concrete Embedments</u>

Corrosion on exposed embedded metal surfaces, which is not progressing and has not resulted in loss of cross section greater than 10%

<u>Concrete Joints</u>

No signs of separation or environmental degradation are present in joints or joint material

<u>Block Walls</u>

The acceptance of possible cracking in block walls should be performed considering the individual plant design analysis (IEB 80-11 or otherwise). Existing analysis may have considered some degree of cracking in the evaluation.

Lateral supports for seismic block wall should be appropriately anchored.

Interfaces between the block walls and concrete floors, walls and floors should show no evidence of damage or movement.

<u>Steel Components</u>

General corrosion with the presence of red iron oxide (rust), surface stains, spots or surface discoloration

General corrosion with the presence of red iron oxide (rust) particles / scale which are easily removed from surface

Localized corrosion with the presence of small diameter pitting (black iron oxide powder in pits indicates active pitting and red iron oxide powder in pits indicates inactive pitting) on exposed (coated or uncoated) metal surfaces that is not progressive

Localized corrosion with the presence of loose rust flakes peeling or blooming from metal surfaces. The loss of cross section is less than 10% and corrosion is not progressive

<u>Secondary Containment In-leakage</u>

The acceptance criteria for the secondary containment draw-down tests are specified in Ref. 7.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a baseline 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 pre-cast 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. The sealant and backing rod used to seal the joint between exterior pre-cast panels on the Unit 1 and Unit 2 reactor buildings has also been replaced to repair degraded caulking.

References

1. *A-44985, Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant, Units 1 and 2*

2. *10CFR50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”*

3. *Westinghouse Owner’s Group Life Cycle Management / License Renewal Program, Altran Corporation / Altran Materials Engineering.*

4. *ACI Committee 349, Repot ACI 349.3R-96, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.”*

5. *NEI 96-03 “Guideline for Monitoring the Condition of Structures at Nuclear Power Plants.”*

6. *NRC Regulatory Guide 1.160, Rev 2 “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”*

7. *Unit 1 and Unit 2 Plant Hatch Technical Specifications, SR 3.6.4.1.4.*