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May 23, 2003

U.S. Nuclear Regulatory Commission
Document Control Desk
Attn: Mr. Russell Arrighi (Mail Stop O-12D-3)
Office of Nuclear Reactor Regulation
Washington, D.C. 20555-0001

Subject: Supplemental Response to LRA Request for Additional Information (RAI)
R. E. Ginna Nuclear Power Plant
Docket No. 50-244

Dear Mr. Arrighi:

This letter is in response to the NRC's March 21 and March 28, 2003 "Request for Additional Information for the Review of the R. E. Ginna Nuclear Power Plant, License Renewal Application". This letter supplements our May 13 response, and provides responses to an additional 62 (for a total of 195) of the 224 RAIs. The balance of the responses will be provided prior to June 12, 2003. Please note that in the March 21 RAI letter, there were two RAIs numbered 3.3-3. The second of those two RAI has been numbered in this response as F-RAI 3.3-3x2.

The RAI response for RAI 2.5-2 has an attached electrical one-line diagram, provided as Attachment 2.

The RAI response for RAI 4.7.5-1 has an attached table, provided as Attachment 3.

I declare under penalty of perjury under the laws of the United States of America that I am authorized by RG&E to make this submittal and that the foregoing is true and correct.

Very truly yours,

Executed on May 23, 2003

Robert C. Mecredy

Attachments

A001

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List of Regulatory Commitments

The following table identifies those actions committed to by Rochester Gas & Electric (RG&E) in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments. Please direct questions regarding these commitments to Mr. George Wrobel, License Renewal Project Manager at (585) 771-3535.

| REGULATORY COMMITMENT | | DUE DATE |
|---|---|---|
| F-RAI 3.3-2 | Add Systems Monitoring as an aging management program applicable to the pipe represented by Table 3.4-2, line number (42). | Prior to 9/2009 |
| F-RAI 3.5-8 | Develop an engineering guidance document that will direct inspections to evaluate galvanic corrosion at susceptible locations in a raw (service) water environment. | Prior to 9/2009 |

R. E. GINNA
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

F-RAI 2.1 -2

Title 10 of the Code of Federal Regulations (CFR) 54(a)(1)(iii) requires, in part, that the applicant consider within the scope of LR those SSC that ensure the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or §100.11. Although the wording in Section 2.1.2, "Plant Level Scoping," of the LRA is consistent with this requirement, the scoping criteria definition documented in Section 3.2.1 of engineering procedure EP-3-S-0713, Revision 1, differs from the wording in 10 CFR 54(a)(1)(iii). Specifically, the EP-3-S-0713 safety-related scoping definition does not refer to offsite exposures comparable to those referred to in §50.34(a)(1) and §50.67(b)(2). Since the scoping implementation procedure does not directly refer to the offsite exposures limitations contained in §50.34(a)(1) and §50.67(b)(2), as applicable, how were these exposure limitations factored into the license renewal scoping and screening process.

Response

The values in 10 CFR 50.34(a)(1) are bounded by those provided in 10 CFR 100.11 (25 rem whole body equals 25 rem TEDE and 300 rem thyroid equals 9 rem TEDE), so only the limiting value was used in the procedure. 10 CFR 50.67(a)(2) applies to licensees who seek to revise their accident source term in design basis radiological consequence analyses, which we do not at this time. However, procedure EP-3-S-0713 has been updated to reflect these two regulations, since the in-scope equipment for license renewal is the same.

F-RAI 2.1 -3

10 CFR 54.21(a) requires, in part, that the applicant identify and list those SSC subject to an aging management review (AMR). The staff's review of Section 2.1.7.4, "Electrical and I&C Systems," of the LRA indicates that only the commodity group that represents the limiting aging characteristic within a plant area receives an AMR. Based on the information presented in the LRA, the staff questioned if this methodology could result in the failure to subject in-scope commodity groups, that are not the most age limited, to an AMR. Provide additional information regarding the screening methodology treatment of electrical and I&C system commodity groups to demonstrate that all in-scope commodity groups are subject to an AMR.

Response

Section 2.1.7.4 describes a process of using a preliminary analysis to avoid inefficiencies in the scoping and screening process. This preliminary analysis focuses on the limiting (bounding) materials of construction and limiting (bounding) environmental conditions. The analysis was used to avoid an exclusionary scoping review for those commodity groups and components that have no aging effects requiring management, or are intended to be included in an aging management program due to regulatory precedent. As stated, initially all passive long lived electrical and I&C commodity groups are considered subject to an AMR. The conclusions of the preliminary analysis do not change this initial position. Only commodity specific, or component specific exclusion scoping are used to identify passive long lived components that are not subject to an AMR. The overall process is consistent with Method B as identified in EPRI 1003057, Section 6. The results of this exclusionary scoping process are provided in response to RAI 2.5-1.

F-RAI 2.1 -6

During the audit of the Ginna scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated final Safety Analysis Report (UFSAR) Supplement," and Appendix B, "Aging Management Activities" to assure that the aging management activities were consistent with the staff's guidance described in Section A.2, "Quality Assurance for Aging Management Programs" and Branch Technical Position IQMB-1, regarding quality assurance (QA) of the LR-SRP.

Based on the staff's evaluation, the descriptions and applicability of the AMPs and their associated attributes to all safety-related and non safety-related SCs provided in Appendix A and Appendix B of the LRA are consistent with the staff's position regarding QA for aging management. However, the applicant has not sufficiently described the use of the QA program and its associated attributes (corrective action, confirmation process, and document control) in the discussions provided for the existing AMPs consistent with those descriptions provided for new programs. The staff requests that the applicant revise or supplement the descriptions in the LRA Appendix A and Appendix B, to include a description of the QA program attributes, including references to pertinent implementing guidance as necessary, which are credited for existing programs. This description should be consistent with the level of detail provided for new program descriptions.

Response

The applicability of the Ginna QA program applies equally to existing programs as to new programs being developed for license renewal. A generic statement regarding the applicability of the Ginna QA program can be made relative to all of the programs credited to manage aging effects for in-scope SSCs as follows:

Corrective Actions

Corrective actions are implemented at Ginna Station in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants", as committed to in Chapter 17 of the Ginna Station UFSAR and described in ND-QAP "Quality Assurance Program". Provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate, are included in the corrective action program.

Corrective actions are implemented through the initiation of an Action Report in accordance with IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (Action) Report". Equipment deficiencies are corrected through the initiation of a Work Order in accordance with A-1603.2, "Work Order Initiation".

Confirmation Process

The confirmation process is part of the corrective action program, which is implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants", as committed to in Chapter 17 of the Ginna Station UFSAR. The aging management activities required by this program would also reveal any unsatisfactory condition due to ineffective corrective action.

IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (Action) Report", includes provisions for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure that effective corrective actions are taken. Potentially adverse trends are also monitored through the Action Report process. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of an Action Report. A-1603.6, "Post-Maintenance/Modification Testing" , includes provisions for verifying the completion and effectiveness of corrective actions for equipment deficiencies. A-1603.6 provides guidance for the selection and documentation of Post-Maintenance Tests (PMTs) or Operability Tests (OPTs), guidelines to ensure equipment will perform its intended function prior to return to service, and guidelines to ensure the original equipment deficiency is corrected and a new deficiency has not been created.

Administrative Controls

The implementing documents are subject to administrative controls, including a formal review and approval process, are implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants", as committed to in Chapter 17 of the Ginna Station UFSAR.

Various procedures provide the required administrative controls, including a formal review and approval process, for procedures and other forms of administrative control documents.

ND-PRO, "Procedures, Instructions and Guidelines" and IP-PRO-3, "Procedure Control", provide guidance on procedures and other administrative control documents. IP-PRO-3 provides guidance on procedure hierarchy and classification, content and format, and preparation, revision, review and approval of Nuclear Directives and all Nuclear Operating Group Procedures. IP-PRO-4, "Procedure Adherence Requirements" establishes procedure usage and adherence requirements. IP-RDM-3, "Ginna Records", delineates the system for review, submittal, receipt, processing, retrieval and disposition of Ginna Station records to meet, as a minimum, the Quality Assurance Program for Station Operation (QAPSO).

F-RAI 2.3 -3

NUREG-1800, Table 2.1-3, states under the heading for consumables, that O-rings are considered consumable items within category (a), which "the applicant would be able to exclude these sub-components using a clear basis." Table 2.1-3 of NUREG-1800 also states that system filters fall within consumables category (d), which "are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from AMR under 10 CFR 54.21(a)(1)(ii). The applicant should identify the standards that are relied on for the replacement as part of the methodology description."

a) LRA Section 2.1.7.7.1 states that O-rings "are considered sub-components of the identified components" (flanges, in this case) "and, therefore, are not subject to their own condition or performance monitoring. Therefore, the AMR for the component has included an evaluation of the sealing materials where it could not be demonstrated that ... the sealing materials are not relied on in the CLB to maintain ... a pressure envelope for a space."

LR drawing 33013-1865-LR depicts the containment purge supply unit. This drawing shows that containment isolation at penetration P204 (location F9) is provided by a blind flange with a double O-ring seal. This flange is closed during Modes 1, 2, 3, and 4 and can only be removed during Mode 6 (refueling). The flange and associated O-ring seal, therefore, serve as a containment boundary for Modes 1 through 4 and perform the intended function of providing a pressure boundary.

Since the subject O-rings are relied upon to provide a pressure boundary, confirm that these O-rings are subject to an AMR, and identify the standards that are relied on for monitoring the performance of this component such that its intended functions are maintained.

b) The LR drawings for the essential ventilation systems show filters within the LR boundary at various locations. LRA Section 2.1.7.1 states that, although certain filters are within the scope of LR, they are periodically replaced and thus are not subject to an AMR as periodic testing and inspection programs are in place to monitor filter performance such that system intended functions are maintained. Describe the plant-specific monitoring program and the specific performance standards and criteria for replacement of filter media for system filters identified below as being within the scope of LR, but not subject to an AMR:

- Charcoal filters shown on LR boundary drawing 33013-1863- LR at locations G3 and D11 and high efficiency particulate air (HEPA) filters shown on the same drawing at locations A2, A5, A8, and I3.
- Moderate efficiency filters shown on LR boundary drawing 33013-1866-LR at locations D2 and D3.
- HEPA and charcoal filters shown on LR boundary drawing 33013-1867- LR at location E3 and a low-efficiency filter shown on the same drawing at location A8.
- Low-efficiency filters shown on LR boundary drawing 33013-1869-LR at locations B3 and D3.

Response

a) The blind flange with double O-ring seals used to provide containment isolation pressure boundaries are in scope to the license renewal rule and are subject to aging management review. LRA Table 3.6-1 line number (6) identifies these components and the programs that monitor the performance of these components. It should be noted that these o-rings are replaced each time a flange is removed.

b) The charcoal and HEPA filters are subject to the requirements of the plant Technical Specification Ventilation Filter Testing Program (TS 5.5.10). This program uses the standards endorsed by Regulatory Guide 1.52, Revision 2, as modified in the specification.
For the low and moderate efficiency (roughing) filters the station periodic surveillance and preventive maintenance program has repetitive tasks (reptasks) which require inspection of the filter condition on a frequency between four and eight weeks, depending on the filter. These frequencies were established through years of operational experience and include consideration of physical location. When a filter shows signs of debris accumulation and fouling it is replaced.

F-RAI 2.3.2.4 -1

License renewal boundary drawing 33013-1278, 2-LR, shows two components identified as "Hot Box" at locations G9 and I9 as subject to an AMR. However, this component is not listed in LRA Table 2.3.2-4, which identifies the components of the containment hydrogen detectors and recombiners system that are subject to an AMR. Clarify where, in the LRA, these components are identified as subject to an AMR or justify their omission.

Response

The "Hot Box" is shown on drawing 33013-1278,1-LR, and is a subcomponent of the containment hydrogen monitor A/B control panel. The Hot Box is an insulated carbon steel enclosure enveloping the H2 analyzer tubing and moisture separator. The space inside the box is heated to 300 degrees F in order to prevent condensation within the analyzer tubing. The devices internal to the Hot Box received a separate aging management review and the components are included in the LRA. Because of its unique nature the Hot Box was evaluated within the component group of pipe. Although the Hot Box is not a pressure boundary component, the Aging Management Programs applicable are included under component type "pipe", material type "carbon/low allow steel" contained in Table 3.3-2 line number (40).

F-RAI 2.3.3.2 -1

A portion of the component cooling water (CCW) system that is subject to an AMR ends at valves 747A and 747B, which are normally shown as open (see LR boundary drawing 33013-1245-LR at locations E8 and F8). There are also numerous portions of the CCW system that are subject to an AMR that end at valves that are normally open to 3/4 inch or less diameter tubing. Failure of the downstream piping may affect the pressure boundary intended function. Section 2.3.3.2 of the LRA does not discuss why this approach is acceptable. Provide additional information to support the basis for this determination. For example, discuss the steps in the procedures for identifying the locations of breaks, for closing the valves, the amount of time required to complete these steps, and the consequences on system inventory if the valves are not closed.

Response

The basis for the acceptability of the aging management review boundary stopping at an open valve is described in LRA Section 2.1.7.1, Mechanical Systems. In addition to flooding and equipment damage from the effects of spray, each location selected needed to be evaluated to ensure that leakage could be detected and isolation performed prior the loss of affected equipment intended function. The affected equipment consideration includes reviewing the equipment serviced by the fluid system and equipment subject to the effects of the leak in the out of scope piping/tubing. The fundamental principle is that a valve position change establishes the pressure boundary at the boundary valve before a failure in the downstream components can cause a loss of intended function. For the CCW system this ruled out establishing a boundary at any open valve in containment simply due to the unlikelihood of identifying leak locations and performing component leak isolation in a timely manner.

Minor CCW leaks from out of scope piping or components should be identified during routine operator tours. Plant specific operating experience has demonstrated the effectiveness of routine tours in leak (usually drip) detection. Should tours fail to detect a leak, plant-operating procedures AP-CCW.2, Loss of CCW during Power Operations and AP-CCW.3, Loss of CCW-Plant Shutdown both direct leak isolation activities for a variety of indications, including lowering CCW surge tank levels.

Valves 747A and 747B were selected as boundary valves because the downstream non-safety related piping is not located in an area containing in-scope equipment that could be affected by spray or flooding. The area is routinely toured and the isolation valves are readily accessible. The flow though the system has an established value of 15 gpm making even an improbable catastrophic failure detectable and isolable before the loss of volume in the CCW surge tank complicates operations. Furthermore, the leak detection procedure requires operators to confirm the desired flows are established to CCW loop components (including those served by 747A and 747B) thus necessitating that the operators physically travel to the areas that contain the out of scope equipment. All other applications of open boundary valves in the CCW system (typically at instrument branch lines) were subject to the same rigorous review as described above. In all cases the determination was made that the usage was consistent with the requirements of NEI 95-10 which require the evaluation boundary includes those portions of the system or structure that are necessary for ensuring that the intended function of the system of structure will be performed.

F-RAI 2.3.3.3 -4

In Table 2.3.3-3 of the LRA, the spent fuel racks appear to be included in the "Structure" component group. The intended functions listed for this component group are (1) providing radiation shielding and (2) providing structural support for safety-related equipment. On the basis of the system description provided in Section 2.3.3.3 of the LRA, the staff questions whether the borated stainless steel spent fuel racks also serve an intended function of reactivity control for LR. Justify not identifying reactivity control as an intended function of the borated stainless steel spent fuel racks, so that the staff may verify compliance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response

The reactivity control functions of the spent fuel racks are indicated in the LRA system description and the associated UFSAR references. RG&E agrees that reactivity control is not explicitly stated as an intended function associated with the structural elements representing the racks. NUREG-1800, Table 2.1-4 identifies "provide radiation shielding" as an intended function but does not identify reactivity control. For the purposes of license renewal, reactivity control is an intended function that was considered. The identification of the reactivity control function is indicated by the relationship made in the LRA between the structural elements describing the racks and Table 3.4-1, line number (9) which addresses neutron absorbing capability.

F-RAI 2.3.3.5 -1

LRA Section 2.4.2.11, "Essential Yard Structures," states that the redundant service water (SW) discharge line is occasionally placed in service for such activities as surveillance testing or maintenance work. License renewal boundary drawing 33013-1250, 2-LR, at location F11 shows a portion of the redundant service water discharge line as a corrugated metal pipe to Deer Creek. This corrugated metal pipe is not shown as being subject to an AMR on that drawing, nor could this pipe be identified in LRA Table 2.3.3-5 under either the pipe or the structure component groups. Obstruction of this flow path could prevent the SW system from performing its intended function when the primary flow path is not in service or unavailable. Justify the exclusion of this corrugated metal pipe from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

In addition, an inspection program was recommended for the Deer Creek culvert in the Ginna SEP (see page 4-7 of NUREG-0821) to minimize the potential for flooding of Deer Creek. Clarify if the corrugated metal SW discharge pipe empties into Deer Creek above or below the culvert identified by the SEP program report. Discuss the measures taken to prevent flooding of the alternate SW discharge, discussed above, if Deer Creek is flooded.

Response

The safety related redundant service water discharge shown on drawing 33013-1250,2-LR flows into an intermediate structure before it makes its way through the corrugated pipe and into Deer Creek. The intermediate structure is a reinforced concrete "pillbox". The concrete "pillbox" is configured to account for the possibility that the normal (testing) discharge path provided by the corrugated pipe becomes blocked. The discharge structure is designed so that discharge flow can exit the "pillbox" through above grade openings. The discharged water then gravity flows across the yard and into Deer Creek. Because the corrugated discharge pipe is only a testing convenience feature it does not perform an intended function, is not within the scope of license renewal and consequently does not require aging management review.

The corrugated pipe empties slightly above the normal Deer Creek culvert (bed). The safety grade "pillbox" empties several feet above that level. The inspections of the Deer Creek culvert referenced in the SEP are done to ensure that debris flowing down, or falling into the creek, do not create a damming effect during periods of high flow and exacerbate any flooding effects. The redundant discharge flow path is always available, even during periods of high flow, because the "pillbox" is located above the top of the creek bank.

F-RAI 2.3.3.6 -2

LRA Table 2.3.3-6 references portions of Tables 3.4-1 and 3.4-2 of the LRA for aging management of the piping component group. However, none of the references in Tables 3.4-1 or 3.4-2 address internal corrosion of buried (underground) ductile iron piping. LRA Section 2.1.6, "Fire Protection Component Aging Management," states the licensee will continue to conduct flow tests as part of the fire water system program described in LRA Appendix B Section B2.1.14. Describe the aspects of this program that address aging management of buried (underground) ductile iron piping. Clarify how flow tests are intended to adequately manage the internal corrosion of the underground fire service water piping.

Response

The Fire Water System Program at Ginna Station is implemented by a number of plant procedures which include activities such as fire pump full-flow capacity tests, velocity flushes of piping and components, operability tests of hydrants and valves, and verification of the capability of the fire water system to maintain pressure during performance tests. The velocity flush procedure includes measurement of flow rate and residual and static pressures, and calculation of the internal pipe roughness at various locations throughout the system. It should be noted that trending data from periodic velocity flushes has accurately identified degraded internal conditions in sections of buried yard loop piping which were subsequently verified by excavation and internal inspection. In one case, it was discovered that a section of unlined ductile iron pipe had been installed during original construction instead of cement-lined pipe as required by piping specifications. In another case, internal obstruction due to biofouling was found at incorrectly installed mechanical clamps. Both conditions were addressed by appropriate corrective maintenance.

In addition to system performance tests, the internal condition of buried system components is evaluated under the Fire Water System Program when they are excavated and disassembled during maintenance activities. Internal remote visual inspections of significant lengths of cement-lined ductile iron pipe have been performed during maintenance activities in 2001 and 2002 and the internal condition of the piping was found to be clean and free of corrosion or obstruction due to fouling/biofouling.

F-RAI 2.3.3.10 -2

Section 7.4 of the UFSAR addresses the alternative shutdown system. The UFSAR states that in case of fire within the control room fire zone, the control room may be evacuated and the plant shut down from alternative shutdown stations located in other areas of the plant. However, systems employed to provide ventilation to the alternative shutdown stations and controls have not been addressed in either the LRA or the UFSAR.

Identify and describe the systems and their components used to provide ventilation to the alternative shutdown stations, and identify which components are within the scope of LR and subject to an AMR in accordance with 10CFR54.4(a)(1) and (a)(2). Provide textual information as well as diagrams which illustrate the LR boundaries for these systems. If any component considered to be within scope is not already included in one of the component groups in LRA Table 2.3.3-10, the appropriate modifications should be made to the table. If the ventilation systems used to service the alternative shutdown stations are not considered to be within the scope of LR, justify their exclusion.

Response

The ventilation system SSCs, where required to support the functioning of equipment used for safe shutdown, are included in the LRA, are within the scope of License Renewal and have received aging management review. The affected components are those ventilation SSCs used to support the operation of the Emergency Diesel Generators, the Technical Support Center diesel generator and battery charger, and the Standby Auxiliary Feed Water pumps. The components used to provide ventilation to the alternative shutdown equipment are included within the LRA in section 2.3.3.10, under "Essential Ventilation Systems". These components are shown on license renewal drawings 33013-1256-LR, 33103-1869-LR and 33013-1873-LR. Other than the TSC ventilation components, all other affected safe shutdown ventilation components are in scope to license renewal because they also support the operation of safety grade equipment. It is important to note that the local control panels ABLIP (Auxiliary Building Local Indicating Panel) and IBLIP (Intermediate Building Local Indicating Panel) used to support safe shutdown do not need ventilation to function and are located in areas where ambient temperatures will not rise to a level where operation is precluded. Additional information on ventilation systems required for safe shutdown is included in the fire hazards analysis and safe shutdown report previously provided to the staff.

F-RAI 2.3.3.11 -1

Section 2.3.3.11 of the LRA states the following:
"The principal components of the Cranes, Hoists and Lifting Devices equipment group include the Reactor Head Lifting Device, the Reactor Internals Lifting Device, and the load carrying elements of the Containment Main Crane, the Auxiliary Building Main Crane, and the Spent Fuel and Containment Refueling Bridge Cranes as well as selected jib and monorail hoists. Included are cables, hooks and the moving load bearing elements."

Supply the following information to support the staff review of the LRA:

a) Are all the "principal components of the Cranes, Hoists and Lifting Devices equipment group" within the scope of LR? If not, identify the components that are within the scope of LR, as delineated in 10 CFR 54.4.

b) Explain which jib and monorail hoists are within the scope of LR.

c) Identify the location (building or structure) for each component (i.e., crane, hoist, jib, monorail hoist, or other lifting device), that is in the "crane" category.

Response

a.) The "principal components of the Cranes, Hoists and Lifting Devices equipment group" are described in the LRA in Section 2.3.3.11, and are consistent with NUREG 0612. Included are cables, hooks, and the moving load bearing elements (i.e., bridges and trolleys). Rails and stationary load bearing elements are evaluated as part of the structures that contain them. The aging management programs for this group are listed in Table 3.4-1 line number (15) in the LRA.

b.) The specific cranes, jibs and monorail hoists which are within scope of license renewal are: containment main overhead crane, containment 3-ton jib, containment fuel manipulator crane, containment 10-ton jib crane, containment 2-ton jib, auxiliary building main overhead crane, auxiliary building SFP bridge crane, auxiliary building RHR pumps monorail, intermediate building 3-ton monorail on the upper level, and the screenhouse overhead crane. This information was provided in our response to NUREG-0612, dated March 2,1983.

c.) The location of each component is identified above.

F-RAI 2.3.3.13 -3

Clarify the following:

a) LR boundary drawing 33013-1866-LR, location H9, shows the following components as requiring an AMR: FT-112, PT-111 and DPS-110. On page 2-169 of the LRA, footnote 1 of Table 2.3.3-13 states: Selected instruments were conservatively included within the scope of LR. Consideration was given to the consequences of an instrument housing pressure boundary failure. Where an instrument was unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included for LR review.

Is this an instance where footnote 1 of Table 2.3.3-13 applies, or is this a typographical error?

b) LRA Section 2.3.3.13, page 2-168, lists 13 drawings for the radiation monitoring system. Nine of these drawings show components of the radiation monitoring system that are subject to an AMR, and four of the drawings show components of the radiation monitoring system that are not subject to an AMR. There are six drawings: 33013-1231, 33013-1245, 33013-1250, 3-LR, 33013-1278, 2, 33013-1893, and 33013-2287 that the list on page 2-168 identifies as having components subject to an AMR. However, none of the drawings shows radiation monitoring system components requiring an AMR. The list on page 2-168 appears to be correct. For example, according to the list, the radiation monitors on the main steam lines, RE-31 and RE-32, shown on LR drawing 33013-1231 are subject to an AMR, while radiation monitor RE-18 on the liquid waste processing monitor skid shown in LR drawing 33013-1271 is not subject to an AMR. In some cases, the drawings themselves indicate that the radiation monitors perform safety significant functions. For example, on drawing 133013-2287-LR, note 2 states that RE-21 performs a safety-significant detection function. However, neither RE-21 nor the connecting piping are shown as requiring an AMR. On drawing 33013-1278, 2-LR, note 3 states that RE-19 and RM-19 combine to perform a safety significant detection function, yet neither of these is shown as requiring an AMR.

Clarify which information, the list of drawings on page 2-168 or the drawings themselves, is correct.

Response

a.) This is a typographical error. FT-112, PT-112 and DPS-110 are not in scope of LRA

b.) As part of the LRA, a "read me first" document was included. This document included instructions explaining how the drawings indicating which SSCs require AMR interact with, and are related to, the lists of drawings associated with systems such as those on LRA page 2-168. The color-coded information on the drawing indicates the SSCs that require AMR. With respect to notes and flags on drawings that indicate safety significant functions; as detailed in LRA Section 2.1.4, Design Codes, Standards and SSC Safety Classifications, and as clarified in the response to RAI 2.3-1, the safety significant (augmented quality) classification is not in and of itself a basis for inclusion within the scope of license renewal. Thus both the lists of drawings and the drawings themselves are correct, but the drawings that indicate which SSCs require AMR are generally more useful.

F-RAI 2.3.4.4 -1

Section 7.2.6 of the Ginna UFSAR states that the anticipated transient without scram (ATWS) mitigation system actuation circuitry (AMSAC) is a non-Class 1E system designed to trip the turbine and start the AFW pumps if main feedwater flow is lost with reactor power above 40 percent. The valves and piping associated with the pressure transmitters have been included in the scope of LR and are listed in LRA Table 2.3.4-4 as being subject to an AMR. Section 2.3.4.4 of the LRA states that pressure sensors for the turbine first-stage pressure provide a signal used in the AMSAC. The turbine stop valves are also identified as being subject to an AMR on LR boundary drawing 33013-1232 at locations B6 and E6. However, the LRA system function listing for code Z4 does not cite the turbine stop valves as having an ATWS intended function. Intended functions should be identified in accordance with the requirements of 10 CFR 54.4(a)(3). Clarify the intended function of the turbine stop valves that led to their inclusion in the scope of LR and being subject to an AMR.

Response

In accordance with 10 CFR 50.62, the scope of ATWS is that "...equipment from the sensor output to final actuation device...to...initiate a turbine trip...". For Ginna Station, that equipment includes the turbine first-stage pressure sensors (sensor output) to the turbine auto stop trip solenoids (final actuation device).

The turbine stop valves are in the scope of License Renewal due to 10 CFR 54.4(a)(2), in that they are the boundary valves for high energy piping, the failure of which could cause damage to safety-related equipment in the Intermediate Building, which is adjacent to the Turbine Building in which the turbine stop valves are located.

F-RAI 2.5 -1

Section 2.5 of the LRA indicates that the electrical and I&C components have been screened and evaluated on a plant-wide basis as component commodity groups rather than on a system basis. Some system level information, however, is provided in that LRA section.

Section 2.1.7.4 of the application indicates that component specific scoping may be performed to limit the number of components for which aging management activities are required, or eliminate aging management activities altogether if nothing remains in the material/environment group population. An example of this is found in Section 3.7 of the application, under the heading Environment, which states that Ginna has four medium voltage power cables installed in underground duct banks, and it was determined that a failure of these cables would not prevent the satisfactory accomplishment of any intended function; therefore, a further review of the environment was not required. Does Ginna have any other underground circuits in the 2 kV or higher voltage range (including 34.5 kV circuits)? If so, include them in the response to the following request.

Identify each of the electrical and I&C components that were eliminated from aging management activities through component specific scoping; and identify the plant SSCs that are served by those components. Provide the basis used in each case for concluding that those SSCs do not provide any LR intended functions identified in 10 CFR 54.4(a).

Response

Ginna station is supplied by the offsite power system via two 34.5 kV circuits. Consistent with interim staff guidance on station blackout (SBO), the evaluation boundary for the offsite power system starts at the 34.5 kV circuit breakers upstream of the startup transformers. The 34.5 kV cables feeding these breakers are outside of the evaluation boundary and therefore were not evaluated as part of license renewal. Additional information is provided in response to RAI 2.5-3.

Consistent with NUREG-1801 Section 2.5.3.1, Ginna station does not provide tables in the LRA of components that are within the scope of license renewal. In addition, tables are not provided with components that are not within the scope of license renewal. Although this information is available at the plant site for inspection, summary information is provided below for each component specifically identified as not subject to an AMR in order to assist the reviewer in determining that all components subject to an AMR have been properly identified, and no inadvertent omissions have been made. The reviewer may use the one-line diagram provided in response to RAI 2.5-2 when considering the components in the 4 kV and offsite power distribution systems. Note that Ginna does have underground 34.5 kV cables that do not perform license renewal intended functions.

Cable M0010 provides the normal 4 kV source of power to circulating water pump A. A credible failure of this cable will result in a loss of power to the circulating water pump. Circulating water pump A does not perform an intended function. In regard to interim staff guidance on station blackout (SBO), this cable is not required to recover from a SBO event.

Cable M0170 provides the normal 4 kV source of power to circulating water pump B. A credible failure of this cable will result in a loss of power to the circulating water pump. Circulating water pump B does not perform an intended function. In regard to interim staff guidance on station blackout (SBO), this cable is not required to recover from a SBO event.

Cable M0089 provides the normal 4 kV source of power to station service transformer 18. This transformer is one of two sources of 480V power for Bus 18. A credible failure of this cable does not result in a loss of an intended function. In regard to interim staff guidance on station blackout (SBO), this cable is not required to recover from a SBO event.

Cable M0108 provides the normal 4 kV source of power to station service transformer 17. This transformer is one of two sources of 480V power for Bus 17. A credible failure of this cable does not result in a loss of an intended function. In regard to interim staff guidance on station blackout (SBO), this cable is not required to recover from a SBO event.

19 kV Iso-phase bus provides power from the main generator to the station unit transformer and the main transformer (generator step-up transformer). A credible failure of this phase bus results in a loss of power generation. In regard to interim staff guidance on station blackout (SBO), this phase bus is not required to recover from a SBO event.

11A/11B Phase Bus provides power from the station unit transformer to 4 kV buses 11A and 11B. A credible failure of this phase bus results in a loss of power generation. In regard to interim staff guidance on station blackout (SBO), this phase bus is not required to recover from a SBO event.

Control Rod Drive bus provides power from the Motor-Generator sets to the reactor trip breakers and the rod drive power distribution system. A credible failure of this bus results in a loss of power to the control rod drive mechanisms and a rod insertion. In regard to interim staff guidance on station blackout (SBO), this phase bus is not required to recover from a SBO event.

115 kV Switchyard Bus provides a connection between the Generator Step-Up transformer and the Offsite Power distribution system. A credible failure of this bus results in a loss of power generation, which is not required to perform an intended function. In regard to interim staff guidance on station blackout (SBO), this switchyard bus is not required to recover from a SBO event.

115 kV High Voltage Insulators are located in the offsite power system to support the 115 kV switchyard bus and related components. These insulators and the equipment supported do not perform an intended function. In regard to interim staff guidance on station blackout (SBO), these insulators are not required to recover from a SBO event.

Uninsulated ground conductors are electrical conductors that are uninsulated and used to make ground connections for electrical equipment. This commodity group does not include those components related to structural lightning protection or cathodic protection. Industry and plant specific operating experience does not indicate that there are any credible failure modes that would adversely impact an intended function; equipment failures due to uninsulated ground conductors are considered hypothetical. In regard to interim staff guidance on station blackout (SBO), these conductors are not required to recover from a SBO event.

F-RAI 2.5 -2

Provide an electrical one-line diagram of the offsite power circuits that are included within the scope of LR. In order to allow the staff to determine whether all the electrical components that have a LR intended function consistent with 10 CFR 54.4(a) have been identified in those circuits, include on the diagram the electrical and physical location of the component/commodity groups listed in Table 2.5.8-1, Offsite Power and any other electrical components not listed in Table 2.5.8-1.

Response

See attached one-line diagram. For additional information see UFSAR Figure 8.1-1.

Upon further review of Table 2.5.8-1, insulated medium voltage cables and connections is not a commodity group that should be included within the offsite power system. While there are 34.5 kV connections in this system, they are not insulated, and are evaluated as part of the switchyard bus. In addition, the description of transmission conductors provided in Section 2.5.1 implies that the 34.5 kV cables that provide power to the station auxiliary transformers are uninsulated. The cables that connect to the 34.5 kV switchyard are insulated and shielded cables, but the cable is spliced to more conventional overhead transmission conductors for circuit 751. This information is provided to enhance the commodity group description in the License Renewal Application, but it does not change the scoping and screening results, nor the aging management review.

F-RAI 2.5 -3

Section 2.5.8 of the LRA indicates that the 115 kV switchyard (Station 13A) is not included within the scope of license renewal. The information in the application also indicates that the 34.5 kV switchyard (Station 204) is not included within the scope of LR. In the Ginna design there are two 34.5 kV circuit breakers shown in UFSAR Figure 8.1-1, upstream of station auxiliary (startup) transformers 12A and 12B, between the transformers and their respective switchyards (Stations 204 and 13A).

The staff guidance on scoping of equipment relied on to meet the requirements of the SBO Rule (10 CFR 50.63) for LR (10 CFR 54.4(a)(3)) was provided to the Nuclear Energy Institute and the Union of Concerned Scientists in a letter dated April 1, 2002. The guidance states that:
For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and the onsite electrical distribution system, and the associated control circuits and structures.

The Ginna offsite power system design is not configured like the typical design described in the guidance. It has the intervening 34.5 kV circuit breakers between the switchyard circuit breakers and the startup (station auxiliary) transformers. In order for the staff to determine whether the plant system portion of the offsite power system should end with the 34.5 kV circuit breakers or with the upstream switchyard circuit breakers at Stations 13A and 204, the staff is seeking to determine which circuit breakers provide the bulk of the plant system electrical services (provide plant power, protect downstream circuits, and provide plant operator-controlled isolation and energization capability). Both groups of circuit breakers clearly provide power to the plant.

Indicate which group of breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits and which group can be tripped open or closed by the Ginna plant operator.

If the bulk of the plant system electrical services are provided by the switchyard circuit breakers and not the 34.5 kV breakers, provide the basis for concluding that the plant system portion of the offsite power system ends with the 34.5 kV circuit breakers rather than the switchyard circuit breakers.

Response

Circuit breakers 52/76702 and 52/75112 are located in the onsite transformer yard. These circuit breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits and are controlled by the plant operators. Ginna Station relies upon the RG&E Energy Control Center to determine the status of 34.5 kV power from Stations 204 and 13A. Procedural guidance for restoration of offsite power does not address the control of circuit breakers upstream of 52/76702 and 52/75112.

F-RAI 3.0 -1

Several of the Ginna AMPs were described by the applicant as being consistent with GALL, but with some deviation from GALL. These deviations are of two types, exceptions and enhancement. Provide detail definition of exception and enhancement used in the LRA.

Response

Deviations from the GALL that are considered exceptions are those that do not agree with, or do not implement, recommendations in GALL program elements (e.g., we do not add biocides to the diesel generator fuel oil, counter to the recommendation of GALL Section XI.M32).

Deviations that are considered enhancements are those that augment the GALL program element recommendations (e.g., we cite a later revision of EPRI reports TR-102134 and TR-105714 than are in the GALL in our Water Chemistry Control program, Section B2.1.37

The rationale for the deviations are provided in the program "Conclusions" section in Appendix B of the Application.

F-RAI 3.3 -2

LRA Section B2.1.21 states that the Ginna Station One-Time Inspection Program will include measures to verify the effectiveness of an existing AMPs and confirm the absence of an aging effect. In LRA Table 3.3-2, line numbers (25), (41), (42), and (66), One-Time Inspection Program is utilized to manage the loss of material for the cast iron heat exchanger in raw water environments, carbon/low alloy steel pipe in air/gas (wetted)<140 and buried environments, and copper alloy (Zn<15%) thermowell in air/gas (wetted) <140 environments, respectively. The applicant is requested to provide the basis that for the above material/environment combinations the One-Time Inspection Program alone is adequate in ensuring that the aging effect will be effectively managed during the extended period of operation.

Response

1) Table 3.3-2, line number (25), cast iron heat exchanger in a raw water environment - a review of Ginna specific operating experience reveals that there has been no age related degradation of this material/environment grouping found. The raw water environment (Service Water system) at Ginna is supplied from Lake Ontario (fresh water) which is not an aggressive environment. Numerous inspections of service water pump casings made of the same material have shown no age related degradation of these pump casings. A one-time inspection will be performed on each Safety Injection pump outboard bearing cooler. The inspection will be completed prior to the end of the initial operating license. Based upon the results of the inspection, an Engineering evaluation will be performed to determine if additional aging management activities will be required.

2) Table 3.3-2, line number (41), carbon/low alloy steel pipe in an air and gas (wetted) < 140 F environment - a review of Ginna specific operating experience for this material/environment grouping shows no instances of age related degradation. This specific piping is associated with the Heating Steam carbon steel piping supply to and from containment that has been cut off and a pipe cap installed by welding at each end. A one-time inspection of the disconnected house heating steam piping segments at penetrations 301 and 303 which have been out of service for over 10 years will be performed prior to the period of extended operation. This inspection will

be performed on the exterior surfaces of the segments utilizing ultrasonic methods and include inspection locations along the bottom and sides of the pipe(s) on the containment and intermediate building sides. Appropriate corrective action will be taken as necessary.

3) Table 3.3-2, line number (42), carbon/low alloy steel pipe in a buried environment - The response to this RAI is associated with RAI B2.1.21-4. The aging management activities associated with this pipe include removing the surrounding fill and performing a One Time inspection to verify that the pipe has not been degraded by corrosion. Omitted from the application was information that the pipe will subsequently be included in the Systems Monitoring Program. Table 3.4-2 line number (42) should also have included Systems Monitoring as an aging management program applicable to this pipe. Hence One-Time inspections alone will not be used for this material/environment combination.

4) Table 3.3-2, line number (66), copper allow (Zn < 15%) thermowell in an air and gas (wetted) < 140 F environment - a review of Ginna specific operating experience reveals no occurrences of age related degradation for this material/environment grouping. Also, a detailed review of NUREG-1801 was performed finding no material/environment grouping of copper alloy (Zn < 15%) in air and gas (wetted) < 140 F. A one-time inspection of components in this material/environment grouping is appropriate to verify the improbability of age related degradation. An evaluation of this inspection will be performed and appropriate corrective action taken. See also response to RAI 3.3-4 and RAI 3.4.9-1.

F-RAI 3.3 -3x2

In LRA Table 3.3-2, line number (11), and Table 3.4-2, line number (81), for stainless steel fasteners (bolting) in the environment of borated water leaks, the applicant identified no aging effects requiring management (AERM). Provide the basis for this determination.

Response

The technical basis for identifying no aging effects requiring management for stainless steel fasteners exposed to borated water leaks is found in EPRI TR-101108, "Boric Acid Corrosion Evaluation Program, Phase 1 - Task 1 Report" and in EPRI TR-104748, "Boric Acid Corrosion Guidebook". These documents contain compilations of pertinent industry experience and summaries of corrosion test data which identify stainless steels and nickel-base alloys as alternative fastener materials which display excellent resistance to corrosion from borated water leaks.

F-RAI 3.4.8 -1

LRA Table 3.4-1, line number (16), states that components within the emergency power system are subject to the OCCW System Program as implemented by the Service Water System Reliability Optimization Program, and that this program is credited with managing the aging effects of loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling. However, in Table 2.3.3-8, under Aging Management Reference, line number (16) is not listed as a link to the AMR for any components (including heat exchanger) covered in the emergency power system. Explain the above discrepancy.

Response

Line number (16) in Table 3.4-1 should be included as an aging management reference in Table 2.3.3-8 for the component group "Heat Exchanger" for both the pressure boundary and heat transfer functions.

F-RAI 3.4.8 -2

LRA Table 3.4-1, line number (17), states that for buried piping and fittings, the Buried Piping and Tank Inspection Program is implemented by the Periodic Surveillance and Preventive Maintenance Program, and that tanks in the emergency power system are periodically inspected for signs of applicable aging effects. However, in Table 2.3.3-8, under aging management, line number (17) is not listed as a link to the AMR for pipe or tank covered in the emergency power system. Explain the above discrepancy. Also discuss how potential aging effects due to corrosion at tank bottom will be managed.

Response

Line number (17) in Table 3.4-1 should be included as an aging management reference in Table 2.3.3-8 for the component group "Tank". The responses to RAIs B2.1.7-1, B2.1.8-1 and B2.1.21-3 provide a discussion related to the management of potential aging effects due to corrosion at the tank bottoms.

F-RAI 3.5 -6

Loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, MIC, and biofouling, and buildup of deposit due to biofouling, could occur in stainless steel and carbon steel heat exchangers and coolers/condensers serviced by OCCW. In Table 3.5-1, line number (9) for loss of material heat exchangers and coolers/condensers serviced by OCCW, the LRA states in the discussion column, "the Periodic Surveillance and Preventive Maintenance Program will be credited with managing the applicable aging effects in lieu of the Open-Cycle Cooling (Service) Water System Program." The applicant's Periodic Surveillance and Preventive Maintenance Program does not specifically identify inspection of these heat exchangers and coolers/condensers serviced by OCCW. The staff requests the applicant identify how the Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, MIC, and biofouling, and buildup of deposit due to biofouling in stainless steel and carbon steel heat exchangers and coolers/condensers serviced by OCCW. Also discuss if the AMP relies on the recommendations of NRC GL 89-13 to ensure that the effects of aging on the OCCW system will be managed for the extended period of operation.

Response

The Periodic Surveillance and Preventive Maintenance (PSPM) program implements the inspections of heat exchangers at Ginna Station that are serviced by open cycle (service) water. The scope of the program now explicitly includes heat exchangers and the program attributes include appropriate references to eddy current inspections of tubing and visual inspections of channel heads. The Open Cycle Cooling Water System (OCCW) program references the PSPM program as the implementing program for these inspections. The OCCW program directs many other activities as well as periodic inspections, and is consistent with the recommendations of Generic Letter 89-13. Therefore, the effects of aging on the OCCW system will be managed for the period of extended operation. For additional information on the Ginna Station PSPM program, see the responses to RAI B2.1.23-1 and B2.1.23-4.

F-RAI 3.5 -8

Tables 3.5-1 and 3.5-2 of the LRA do not identify galvanic corrosion as an aging effect that requires management for the SPCS. Galvanic corrosion could occur at bimetallic joints in a raw water environment where the water chemistry is not controlled. This condition normally exists for the raw water side of heat exchangers. Do any conditions exists where SPCS piping or components at Ginna should be managed for galvanic corrosion? If conditions do exist, explain how these components are managed for galvanic corrosion.

Response

Loss of material due to galvanic corrosion was evaluated during the aging management review process as an applicable aging effect/mechanism. It is recognized that Tables 3.5-1 and 3.5-2 do not identify galvanic corrosion as an aging mechanism. Therefore, an engineering guidance document will be written directing inspections to evaluate galvanic corrosion at susceptible locations in raw water environments. These inspections will be performed under the One-Time Inspection program. The guidance document shall include acceptance criteria, guidance for evaluation of results, a requirement for follow-up inspections based on the initial inspection results if necessary, a requirement for initiation of an Action Report for any indication of degradation exceeding acceptance criteria and requiring engineering evaluation or resolution, and the time frame during which the components shall be inspected (note: all inspections will be completed before the period of extended operation).

F-RAI 3.5 -11

LRA Table 3.5.2, line numbers (20) and (21), identify the One-Time Inspection Program as managing loss of heat transfer and loss of material for heat exchangers in a raw water environment. The NUREG-1801 AMP for managing these aging effects is the OCCW System Program. Explain how the One-Time Inspection Program will manage these aging effects. Discuss if the AMP relies on the recommendations of NRC GL 89-13 to ensure that the effects of aging on the OCCW system will be managed for the extended period of operation. Also, use of the One-Time Inspection Program does not appear to be consistent with Table 3.5-1, line number (9), where the applicant identifies their Periodic Surveillance and Preventive Maintenance Program to managed similar aging effects for heat exchangers in an OCCW environment.

Response

Line numbers (20) and (21) in Table 3.5-2 refer to the cast iron outboard bearing oil coolers for the two motor-driven and one turbine-driven auxiliary feedwater pumps. These coolers are of similar design to those on the safety injection (SI) pumps. These coolers consist of a cast iron chamber through which service water flows to provide cooling. Service water at Ginna Station is fresh Lake Ontario water and is not aggressive. The resistance of gray cast iron to fresh Lake Ontario water is discussed in the response to RAI 3.4.9-1.

A performance test is performed periodically on the SI pump outboard bearing coolers to verify service water flow. No evidence of reduction in flow has ever been detected. As a result of the excellent resistance of gray cast iron to service water at Ginna Station, aging effects would either not be expected to occur or would be expected to occur so slowly as to be essentially negligible. Therefore a one-time inspection of the outboard bearing coolers is appropriate to verify that the coolers will continue to perform their intended functions during the period of extended operation.

Table 3.5-1 line number (9) refers to the lube oil coolers for the motor-driven and turbine driven auxiliary feedwater pumps. These coolers are stainless steel shell-and-tube heat exchangers that are cleaned and inspected periodically under the Periodic Surveillance and Preventive Maintenance (PSPM) program. Service water flows through the tube side of these units and lubricating oil through the shell side. Plant-specific operating experience has shown that these lube oil coolers are susceptible to tube-side fouling. Therefore these coolers are periodically cleaned and inspected as directed by the PSPM program in support of the Open Cycle Cooling Water System Program which incorporates the recommendations of GL 89-13.

<u>F-RAI 3.5 -12</u>

A one-time inspection can be used to address concerns for the potential long incubation period for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there is to be confirmation (by one-time inspection) that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. Based on these guidelines, provide operating experience to confirm that the aging effect is not expected to occur or is expected to progress very slowly for the pipe identified in Table 3.5-2, line number (29).

<u>Response</u>

Table 3.5-2, line number (29), refers to the carbon steel tailpieces for the atmospheric relief valves. An inspection of these tailpieces will be performed to determine whether significant degradation has occurred. These components will subsequently be included in the Periodic Surveillance and Preventive Maintenance program. Table 3.5-2 line number (29) should also have included the Periodic Surveillance and Preventive Maintenance program as an applicable aging management program.

<u>F-RAI 3.6 -1</u>

Section 2.4.1 adequately describes the unique nature of the containment structure support system. However, neither Table 2.4.1-1 grouping nor the line numbers in Table 3.6-2 include the AMR for components (e.g. neoprene (lubrite?) bearing pads, tension rods) associated with the support system. The applicant is requested to provide information regarding the aging management of the accessible portions of the support system, and evaluation of the inaccessible portion of the support system that would ensure its (support system's) ability to stay functional during the extended period of operation.

<u>Response</u>

The accessible portions of the unique containment support system at Ginna Station include the upper wall-tendon anchorage hardware and grease cans. The inaccessible portions of the support system include the neoprene bearing pads, radial tension rods, and rock-anchors.

Each of the 160 vertical wall tendons, consisting of 90, ¼ inch diameter wire bundles is connected at the base of the containment wall to another 90-wire tendon that is anchored by grouting into a 6-inch diameter hole drilled 43 feet into the base rock. These rock anchors were prestressed prior to construction of the containment. The functionality of this unique support system is monitored for structural adequacy by periodic tendon surveillance lift-off tests performed under plant procedure PT 27.2, "Tendon Surveillance Program". This procedure requires measurement of tendon lift-off forces, comparison of measured lift-off forces with predicted forces, evaluation of 6% overstress capability, inspection and testing of surveillance wire specimens, analytical testing of casing filler grease samples, and visual examination of tendon anchorage hardware and grease cans.

The condition of other inaccessible components such as the neoprene pads and radial tension rods is inferred from visual examinations of the accessible portions of the containment structure such as the ring beam and containment wall surfaces performed under the ASME Section XI, Subsection IWE/IWL Program and the Structures Monitoring Program.

F-RAI 3.6 -6

For many of the LRA Table 3.6-1 and 3.6-2 entries, in addition to the GALL- recommended AMP (i.e., the Structures Monitoring Program), the Periodic Surveillance and Preventive Maintenance AMP is listed. For each of these cases, clarify the relationship between the Periodic Surveillance and Preventive Maintenance AMP and the other listed AMPs with respect to the managing of the aging effects identified for the components in Tables 3.6-1 and 3.6-2.

Response

In Table 3.6-1 the ASME Section XI, Subsections IWE & IWL ISI (Containment ISI) program and the Structures Monitoring program are referenced as the approved NUREG-1801 aging management programs for structural components and component supports. However, for certain components, the Periodic Surveillance and Preventive Maintenance (PSPM) program was also credited for managing the effects of aging because periodic inspections of these components are driven by repetitive tasks (reptasks) in the PSPM program. For example, the PSPM program is credited along with the Containment ISI program for managing the effects of aging for the Containment personnel airlock and equipment hatch [line numbers (4) and (5)] seals, gaskets and moisture barriers [line number (6)], and tendon and anchorage components [line number (14)]. An explanation for crediting the PSPM program is provided in the discussion column for these line numbers.

As stated in the discussion for Table 3.6-1, line number (18) and further clarified in the discussion for Table 3.6-2, line number (7), the Structures Monitoring program and the PSPM program are credited for aging management of water control structures since periodic inspections of specific water control structures are driven by reptasks in the PSPM program. Similarly, the PSPM program was credited for aging management of component supports in Table 3.6-1, line number (25), since periodic inspections of supports submerged in raw water are driven by reptasks in the PSPM program.

Table 3.6-2, line number (17) is intended to address the effects of borated water leakage from the refueling cavity liners on other carbon steel components which may be degraded by exposure to the leakage. As stated in the discussion for this line number, a reptask in the PSPM program drives periodic inspections of these components for management of the effects of aging.

F-RAI 3.6 -9

Line number (17) of Table 3.6-2 discusses an applicable aging effect (loss of material) that will be managed for stainless steel components (refueling cavity, fuel transfer liners, and attachments) of the Containment Vessel through the dual application of the Boric Acid Corrosion and Periodic Surveillance and Preventive Maintenance Programs. However, no aging effect is listed for this component entry (Table 3.6-2 line number (17)). Clarify this discrepancy.

Response

Table 3.6-2, line number (17) is intended to address the effects of borated water leakage from the refueling cavity liners on other carbon steel components which may be degraded by exposure to the leakage. As described in the discussion for this line number, a reptask in the PSPM program drives periodic inspections of these components for management of the effects of aging. The refueling cavity liner, fuel transfer liner and attachments are stainless steel and therefore not susceptible to the effects of aging from exposure to borated water. Therefore no aging effects requiring management were identified for the liners and their attachments.

F-RAI 3.6 -16

The GALL report recommends further evaluation to manage the aging effect loss of material due to corrosion for the embedded containment liner, if corrosion of the embedded liner is significant. The aging management program recommended by the GALL report for managing loss of material for accessible steel elements within the containment structure is the ASME Section XI, Subsection IWE (XI.S1) Program. Subsection IWE exempts from examination portions of the containment that are inaccessible, such as embedded or inaccessible portions of steel liners and steel containment shells, piping, and valves penetrating or attaching to the containment. To cover inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The applicant addressed the above criterion defined in the GALL report, regarding the need for further evaluation to manage the aging of the potential aging of the embedded containment liner, in line number (12) of LRA Table 3.6-1. Line number (12) states that "the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program includes inspections and leak rate tests which would indicate the presence of significant degradation due to loss of material from all applicable corrosion mechanisms." This statement does not adequately address the further evaluation criterion stated in the GALL report for the embedded containment liner plate.

Provide information, as recommended by the GALL report for item II.A1.2-a, to show that the embedded portion of the steel containment liner plate has not experienced significant loss of material due to corrosion. Otherwise, provide an AMP for the inaccessible portions of the containment liner plate.

Response

Review of plant-specific operating experience and recent maintenance and corrective action documents identified only one nonconforming condition at the moisture barrier (caulking) which protects the inaccessible portion of the Containment steel liner from corrosion. This condition was discovered during inservice inspections performed to meet the requirements of ASME

Section XI, Subsection IWE in 2000. As discussed in the response to RAI B2.1.3-3, insulation was removed and the liner was exposed for visual inspection in two areas. Evidence of minor surface corrosion was present in the area with the nonconforming caulking detail. Ultrasonic thickness readings were taken in both areas, including locations above and along the interface between the liner and the Containment concrete floor. All measured values exceeded the minimum required thickness with considerable margin. The liner was cleaned, re-coated and the moisture barrier restored in accordance with original design specification requirements in both areas.

As a result of this discovery, the configuration of the moisture barrier was inspected around the entire circumference of the Containment and verified to be intact with no visible gaps or discontinuities. Additional inspections of the liner were performed during the 2002 refueling outage. As discussed in the response to RAI B2.1.3-3, approximately 70 linear feet of the liner were exposed and ultrasonic thickness measurements taken at four different excavated areas below the floor level. These measurements verified that no loss of liner thickness had occurred at these locations. The exposed portion of the liner was again cleaned, re-coated, and the moisture barrier restored in accordance with original design specification requirements.

Additional inspections of the moisture barrier and liner are planned during the second and third periods of the Fourth ISI interval, which commenced on January 1, 2000. The condition of the inaccessible portions of the Containment liner may be assessed by evaluation of the condition of the liner at the interface with the concrete floor. Therefore, inspections performed under the ASME Section XI, Subsections IWE/IWL ISI Program will provide reasonable assurance that aging effects for the inaccessible portions of the liner plate can be managed so that the liner plate will continue to perform its intended function consistent with the current licensing basis during the period of extended operation.

F-RAI 3.7 -1

Section 3.7 of the LRA, under the heading environment states that a review of plant design documentation was performed to quantify the environmental conditions to which Ginna Station equipment is exposed. State whether actual temperatures of the electrical equipment areas were measured, and whether walkdowns of these areas were performed for LR? If not, how was the design documentation validated, and how were adverse localized environments in the electrical equipment areas identified, leading to a conclusion that the effects of aging will be adequately managed consistent with the requirements of 10 CFR 54.21(a)(3)?

Response

Engineering staff conducted a review of actual plant environments using the six containment temperature RTDs, RTDs used for EQ program re-evaluation, heat stress temperature reports, and thermometers used for routine operator rounds. In addition, a plant walkdown was conducted for the license renewal project in accordance with EPRI TR-109619 to confirm the adequacy of the aging management program. The conclusions of the review and walkdown confirm that the UFSAR is conservative for ambient plant environments and the aging management program will effectively identify adverse localized equipment environments.

That being said, Ginna Station does not limit the scope of the Non-EQ Insulated Cables and Connections Aging Management Program to those locations with adverse localized equipment environments (see response to RAI 3.7-2). All environments containing electrical equipment subject to an AMR are included in the scope of the program and exceptions are specifically stated. Therefore Ginna station has reasonable assurance that the effects of aging will be adequately managed consistent with the requirements of 10CFR54.21(a)(3).

F-RAI 3.7 -5

a) The discussion in line number (1) Electrical Phase Bus of Table 3.7-2 of the license renewal application (LRA) indicates that because a one-time inspection found no aging effects requiring management (AERM), no additional aging management programs (AMPs) are required through the period of extended operation. The potential AERMs identified in line number (1) for the electrical phase bus appear to be associated with organic insulating components of phase bus, although the material column in the table only identifies porcelain insulators at Ginna. NRC Information Notice 89-64, a recent LRA, and information from an engineering forum on the internet, identify bus duct insulation problems requiring management. IN 89-64 indicates a combination of cracked insulation and accumulation of dust, debris, and moisture caused failure of the bus. Corrective actions included enhanced periodic inspections and cleaning of bus bars and their housings.

Provide a description of your AMP, in accordance with the requirements of 10 CFR 54.21(a)(3), used to detect aging effects associated with phase bus insulation components; or provide justification why such a program is not needed.

b) Line number (1) Electrical Phase Bus of Table 3.7-2 does not address aging effects associated with the metallic electrical current carrying components of the phase bus. Has the applicant considered oxidation and corrosion of the metallic components, or loosening of the fastener components? For example, oxidation of aluminum electrical connections can be problematic. The oxidation can create a high resistance connection resulting in additional heating at the connection and further oxidation until failure occurs.

With regard to the fasteners, reference 1 to Section 3.7 of the LRA, Aging Management Guideline for Commercial Nuclear Power Plants, on page 4-38 states:

Circuits exposed to appreciable ohmic or ambient heating during operation may experience loosening related to the repeated cycling of connected loads or of the ambient temperature environment ... Repeated cycling in this fashion can produce loosening of the termination under ambient conditions, and may lead to high electrical resistance joints or eventual separation of the termination from the conductor.

Similarly, NRC Information Notice 2000-14 identifies the phenomenon of "torque relaxation" that can lead to overheating and arcing at the bus joint connection.

Provide a description of your AMP, in accordance with the requirements of 10 CFR 54.21(a)(3), used to detect aging effects associated with oxidation and corrosion of metallic components, and loosening of fastener components in the electrical phase bus; or provide justification why such a program is not needed.

Response

a) The methodology for performing and Aging Management Review at Ginna Station includes a review of applicable information notices. Ginna has also reviewed and incorporated guidance as applicable from EPRI 1003057, which was developed based in part upon all License Renewal Applications submitted prior to its publication in December 2001. However, the AMR methodology does not include reviews of "engineering forums on the internet" and therefore this response makes no attempt to address sources that are not a part of the approved methodology.

Information Notice 89-64 provides examples from several incidents of bus bar failure from various nuclear power plants. The primary focus of this notice is failure of insulation. In some cases, the design of the phase bus contributed to insulation failure, while in other cases, material compatibility appeared to be of concern. Ginna Station evaluated the plant specific design and found that it is highly resistance to the conditions identified in the information notice. Specifically, Ginna Station does not have vents on the top of the phase bus. Such a design would allow for moisture and debris to enter the bus from above. This appears to be the design of at least two plants discussed in the information notice. Since the concern of material compatibility could not be readily evaluated, a one-time inspection was performed to visually inspect the condition of the phase bus components. This inspection confirmed the integrity of the insulation and hardware. The failures discussed in the information notice require the presence of moisture, debris (contaminants), and insulation failure. No insulation failure or moisture was observed, and the level of "dust" in the housings of the original plant phase bus was considered insignificant. There was no appreciable "dust" in the phase bus replaced in 1989. Based on analysis, review of operating experience, a review of EPRI 1003057, and an inspection, there are no aging effects requiring evaluation during the period of extended operation.

b) Reference 1 in the LRA Section 3.7 was written to address the scope of electrical cable systems, including terminations. The use of this discussion in the context of electrical phase bus may be inappropriate. However, recognizing the validity of the concern, Ginna station reviewed applicable operating experience such as Information Notice 2000-14 as part of the Aging Management Review for Electrical/I&C Components.

Information notice 2000-14 identifies several causes of bus bar failure. Most of these causes are related to very high loading of the bus, in addition to potential undetected damage from a previous transformer explosion. The phase bus at Ginna Station that are within the scope of license renewal have normal loading that is less than 25% of bus ampacity. Therefore heating of the conductors is minimal and thermal cycling of the bus connections is not considered significant. The conditions discussed in the information notice are not applicable to the in scope phase bus at Ginna Station.

The Aging Management Review for Electrical/I&C Components specifically addresses phase bus connection surface oxidation, bus bar insulation degradation, and conductor temperature rise. As part of this review, design and installation documents were evaluated from original plant construction and the 1989 partial phase bus replacement (offsite power reconfiguration project). This review confirmed that Penetrox (or equivalent) anti-oxidation material was used for splice connections. The conclusion of the Ginna Station evaluation determined that there are no aging effects requiring management for phase bus throughout the period of extended operation. Therefore an aging management program is not required.

F-RAI 3.7 -6

The discussion in line number (2) Switchyard Bus of Table 3.7-2 of the application states: Plant operating experience reviews show that the activities performed by the Energy Delivery Department on the Switchyard Buses are effective in managing Switchyard Bus components.

It appears that the activities performed by the Energy Delivery Department constitute the makings of an AMP for the switchyard bus that should be included under license renewal in accordance with the requirements of 10 CFR 54.21(a)(3). Describe the ten attributes of the switchyard bus aging management program consistent with the guidance provided in Branch Technical Position RLSB-1 of the staff's license renewal Standard Review Plan (NUREG-1800). Include a discussion in your response addressing the metallic topic portion of Question 3.7-5 above.

Response

The activities performed by the Energy Delivery Department are not being credited as an aging management program. As noted in the discussion, plant operating experience has not identified that the aging effects for copper and stainless steels in non-marine atmospheric environments results in degradation requiring aging management. Also, a review of NUREG 1801 did not identify a need to provide an aging management program for these material/environment combinations.

The intent of the discussion for line number (2) on Table 3.7-2 was to provide the staff with information that we monitor the operation and condition of this equipment using a process that would require root cause investigation and corrective action - the maintenance rule process. If conditions warrant, exceeding maintenance rule performance criteria would require the establishment of goals, the assignment of a program to prevent recurrence and monitoring to ensure effectiveness. This rationale is consistent with the license renewal statements of considerations (SOC) where, in part (iv), Integration of the Regulatory Process and the Maintenance Rule with License Renewal, it states:
"... the Commission has determined that the license renewal rule should credit existing maintenance activities and maintenance rule requirements of most structures and components. Recognition that the licensee activities associated with the implementation of the maintenance rule will continue throughout the renewal period and are consistent with the first principle of license renewal is fundamental to establishing credit for the existing programs and the requirements of the maintenance rule. As a result, the requirements in this rule reflect a greater reliance on existing licensee programs that manage the detrimental effects of aging on functionality, including those activities implemented to meet the requirements of the maintenance rule."

Because those portions of the switchyard bus that are in-scope to the rule have not exhibited any aging effect requiring management and because any detrimental effect of aging on their functionality is monitored by the maintenance rule, no further License Renewal Programs need be applied.

F-RAI 3.7 -7

The discussion in line number (3) high voltage insulators of Table 3.7-2 of the LRA states: Plant operating experience reviews show that the activities performed by the Energy Delivery Department on the high voltage insulators are effective in managing phase bus components.

It appears that the activities performed by the Energy Delivery Department constitute the makings of an AMP for the high voltage insulators that should be included under LR in accordance with the requirements of 10 CFR 54.21(a)(3). Describe the ten attributes of the high voltage insulator aging management program consistent with the guidance provided in Branch Technical Position RLSB-1 of the staff's license renewal Standard Review Plan (NUREG-1800).

Response

The activities performed by the Energy Delivery Department are not being credited as a aging management program. As noted in the discussion, plant operating experience has not identified that the aging effects for high voltage insulator materials in non-marine atmospheric environments results in degradation requiring aging management. Also, a review of NUREG 1801 did not identify a need to provide an aging management program for these material/environment combinations.

The intent of the discussion for line number (3) on Table 3.7-2 was to provide the staff with information that we monitor the operation and condition of this equipment using a process that would require root cause investigation and corrective action – the maintenance rule process. If conditions warrant, exceeding maintenance rule performance criteria would require the establishment of goals, the assignment of a program to prevent recurrence and monitoring to ensure effectiveness. This rationale is consistent with the license renewal statements of considerations (SOC) where, in part (iv), Integration of the Regulatory Process and the Maintenance Rule with License Renewal, it states:
".. the Commission has determined that the license renewal rule should credit existing maintenance activities and maintenance rule requirements of most structures and components. Recognition that the licensee activities associated with the implementation of the maintenance rule will continue throughout the renewal period and are consistent with the first principle of license renewal is fundamental to establishing credit for the existing programs and the requirements of the maintenance rule. As a result, the requirements in this rule reflect a greater reliance on existing licensee programs that manage the detrimental effects of aging on functionality, including those activities implemented to meet the requirements of the maintenance rule."

Because those high voltage insulators that are in-scope to the rule have not exhibited any aging effect requiring management and because any detrimental effect of aging on their functionality is monitored by the maintenance rule, no further License Renewal Programs need be applied.

F-RAI 3.7 -8

Section B2.1.11.7 of the LRA describes the corrective actions attribute of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. It indicates that all unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation that will consider the age and operating environment of the component.

Will the engineering evaluation consider the potential for moisture in the environment of cables and connections that are found to have jacket surface anomalies? Several aging management references (SAND96-0344, EPRI TR-103834-P1-2, and Aging and Life Extension of Major Light Water Reactor Components edited by V.N. Shaw and P.E. MacDonald) indicate that a moist environment can hasten the failure of circuits that have previously undergone age-related degradation from other means, such as thermal or radiation exposure. If your engineering evaluation does not consider the potential for moisture in the area of degraded cables and connections, please provide the technical basis for why it has been excluded. This information is necessary to ensure the aging of non-EQ cables connections are appropriately managed consistent with the requirements in 10 CFR 54.21(a)(3).

Response

The Aging Management Program provided for Electrical Cables and Connections Not Subject to 10CFR50.49, encompasses NUREG-1801 Section XI.E1, and therefore further review of this program should not be necessary. Consistent with NUREG-1801 Section XI.E1, all unacceptable visual indications of cable and connection jacket surface anomolies are subject to an engineering evaluation that will consider the age and operating environment of the component. For most accessible cables, moisture is an unacceptable visual indication and would be appropriately addressed as part of the plant corrective action program. For selected instrumentation cables sensitive to a reduction in insulation resistance (from moisture or otherwise), a separate aging management program has been provided in response to RAI 3.7-3.

F-RAI 4.1 -1

Table 4.1-1 of the LRA identifies TLAAs applicable to the Ginna Station. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other LRAs. The LRA indicates that NUREG-1800 was used as a source to identify potential TLAAs. For those TLAAs listed in Tables 4.1-2 and 4.1-3 of NUREG-1800, that are applicable to PWR facilities and not included in Table 4.1-1 of the LRA, discuss whether there are any calculations or analyses that address these topics at the Ginna Station. If calculations or analyses exist that address these topics, discuss how the these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 50.3.

Response

NUREG-1800 Table 4.1-2 TLAA Comparison:
Reactor vessel neutron embrittlement - provided in Section 4.2 of the LRA
Concrete containment tendon prestress - provided in Section 4.5 of the LRA
Environmental Qualification of Electrical Equipment - provided in Section 4.4 of the LRS
Metal corrosion allowance -metal corrosion allowance was used in supplier calculations, but was never included in the CLB and therefore does not meet the sixth TLAA criterion.
Inservice flaw growth analysis - provided in Sections 4.3.5 and 4.3.6 of the LRA.
Inservice local metal containment corrosion allowance - Ginna Station has a reinforced concrete containment; therefore, the metal containment corrosion allowance is not applicable.
High energy line break postulation based on fatigue CUF - These locations were developed using an effects-oriented approach, rather than using fatigue cumulative usage factor.

SRP Table 4.1-3, TLAAs comparison:
- Intergranular separation of reactor vessel low alloy steel under austenitic stainless steel clad is addressed in Section 4.3.3.
- LTOP analyses are included in 4.2.2.
- No specific fatigue analysis was done for the Turbine Driven Auxiliary Feedwater steam supply lines. However, they are B31.1 lines, and are covered under Section 4.3.2.
- RCP flywheel is addressed in Section 4.7.6

- Ginna does not have a polar crane, but Section 4.7.5 discusses crane load cycle limits.
- Reactor vessel internals and transient cycles is addressed in Section 4.3.1.
- Leak before break is discussed in Section 4.7.7.
- Fatigue analysis of the liner plate, and containment pressurization cycles, are discussed in Section 4.6.

F-RAI 4.3.3 -1

In Section 4.3.3 of the LRA it is stated that the NRC reviewed WCAP-15338 and included two applicant action items to verify that a plant is bounded by the report evaluation and that the TLAA be described in the plant UFSAR Supplement. For the plant to be bound by WCAP-15338 it must be bound by the number of cycles and transients assumed in WCAP-15338. The staff requests that the applicant confirm that the projected number of cycles for the Ginna reactor vessel at the end of the period of the extended license is less than the number of cycles in the WCAP-15338 analysis.

Response

The analysis of the number of cycles and transients has been accomplished and are within the assumed bounds of WCAP-15338. See also the response to RAI 4.3.1-1 for details.

F-RAI 4.7.3 -4

Provide detailed clarification why this fatigue analysis may not meet the definition of a TLAA, as described in 10 CFR 54.3.

Response

This information was located in vendor calculations, and it is not apparent it was submitted to the NRC and made part of the Ginna CLB. Therefore, the 6th element of a TLAA may not have been met. The results were included for conservatism.

F-RAI 4.7.5 -1

Section 4.7.5 of the LRA indicates that the estimated cycle numbers were compared to the design load cycles and that the estimated numbers are well below the upper design load cycle limit. Provide the estimated number of load cycles and also the assumptions used in the estimation. In addition provide the upper design loading cycle limit.

Response

The requested data is provided in the attached table, extracted from Design Analysis DA-2002-016-03, "Containment Time -Limited Aging Analyses For License Renewal Calculation of Crane Load Cycles and Fatigue Evaluation". Most loads are significantly below the capacity of the cranes. Where the loads are near or comparable to the rated capacity of the cranes, the number of cycles is significantly below the design loading cycles, reducing fatigue loading on the cranes.

F-RAI 4.7.5 -2

Section 4.7.5 of the LRA states that the average percent of the rated load lifted is less than 50% for the design load cycles. Provide assurance that this percentage will not change in the future during the period of extended operation.

Response

As can be seen from the table included in the response to RAI 4.7.5-1, the percentages are based on the types of loads the cranes are designed to lift, versus their capacity. Any projected load lifts above 50% capacity have a frequency that is only a small percentage of the design loading cycles. The crane duty is not expected to change between now and 2029. Any significant changes would be subject to engineering analysis.

F-RAI 4.7.6 -1

The UFSAR Supplement does not describe the RCP flywheel TLAA. Therefore, the applicant is requested to update the UFSAR Supplement to include this TLAA.

Response

A new UFSAR Supplement regarding the RCP flywheel should be provided in Appendix A of the LRA :

During normal operation, the reactor coolant pump (RCP) flywheel possesses sufficient kinetic energy to produce high energy missiles in the event of failure.The aging effect of concern is fatigue flaw growth in the flywheel bore keyway. In accordance with our ISI program, RG&E performs an examination once every ten years. The method of examination includes either an ultrasonic examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius, or an ultrasonic and a surface examination of exposed surfaces defined by the volume of the disassembled flywheel.

F-RAI B2.1.1 -1

The applicant stated that this program is not specifically used for aging management at Ginna station as it is implemented by the Systems Monitoring and One-Time Inspection Programs.

a) Confirm and discuss whether the subject aging program is consistent with the guidelines provided in AMP XI.M29, "Aboveground Carbon Steel Tanks" of NUREG-1801. Also identify all deviations from the guidelines in AMP XI.M29 and provide justification for each deviation.

b) The staff notes that a one-time inspection of the reactor makeup water tank prior to the period of extended operation will be performed for tank bottom thickness measurements. Provide justification for not performing one-time inspection on the other aboveground carbon steel tanks.

c) The staff notes that the bottom thickness measurement of the aboveground carbon steel tanks are not identified in the scope of program of the One-Time Inspection Program. Since the subject program will not be specifically used for aging management at Ginna station, the performance of bottom thickness measurement of the aboveground carbon steel tanks should be identified in the scope of One-Time Inspection Program.

d) This program should provide guidance for selecting locations with the highest likelihood of corrosion problems for thickness measurements such as the locations where there is observed degradation of sealant or caulking at the interface edge between the tank and foundation, which would allow penetration of water and moisture and cause corrosion of the bottom surface.

e) Provide guidance in this programs for sample expansion and increasing frequency of inspection when surface degradation is observed.

Response

a) The Ginna Station Aboveground Carbon Steel Tanks program is consistent with, but includes one exception to, the guidelines provided in NUREG-1801, Section XI.M29. The exception is that protective coatings, although used on carbon steel tanks at Ginna Station, are not credited for mitigating the effects of aging. An assessment of the condition of the coatings is used to assist in assessing the condition of the carbon steel surfaces.

b) A thorough inspection of the reactor make-up water storage tank was performed in 2001. This tank is a cylindrical tank mounted vertically with a flat bottom that rests directly on the concrete floor. The inspection scope included visual examination of the interior surfaces of the tank, and ultrasonic thickness measurements of the tank bottom. The coating on the interior surfaces of the tank was in excellent condition, with no evidence of blistering, peeling, flaking, or substrate corrosion on the walls or bottom. The thickness measurements indicated no evidence of wall loss due to corrosion of the tank bottom. Other flat-bottomed aboveground carbon steel tanks in the scope of license renewal at Ginna Station include the "A" and "B" emergency diesel generator (EDG) fuel oil day tanks, the TSC diesel generator fuel oil day tank, and the "A" and "B" condensate storage tanks. The EDG fuel oil day tanks and the TSC diesel generator fuel oil day tank are mounted on pedestals and, as such, the bottom surfaces of the tanks do not rest on concrete and are accessible for visual inspection. These tanks, including the exterior surface of the tank bottoms, will be inspected during the 2003 refueling outage at Ginna Station. The "A" and "B" condensate storage tanks are cylindrical tanks mounted vertically with flat bottoms that rest directly on the concrete floor. These tanks will be drained and inspected during Cycle 31 (2003-2004). Ultrasonic thickness measurements of the tank bottoms will also be performed at that time. The remaining aboveground carbon steel tanks in the scope of license renewal are the "A" and "B" accumulator vessels and the diesel fire pump fuel oil storage tank. The accumulator vessels are vertically oriented cylindrical vessels with dished heads and are supported by skirts. The interior of these vessels is clad with stainless steel. The diesel fire pump fuel oil storage tank is a cylindrical tank mounted horizontally on pedestals. The exterior surfaces of these tanks are accessible for visual inspection during system engineer walkdowns.

c) Ultrasonic thickness measurements of the bottom surfaces of aboveground carbon steel tanks are now included in the scope of the One-Time Inspection program.

d) Guidance for selecting locations for thickness measurements where evidence of degradation of sealants and caulking exists is now provided in the Aboveground Carbon Steel Tanks program.

e) Thickness measurements will be performed on the bottom surfaces of all carbon steel tanks that rest directly on concrete and are within the scope of license renewal at Ginna Station. Guidance for additional measurements and inspections in the event that degradation is detected is now provided in the Aboveground Carbon Steel Tanks program.

F-RAI B2.1.3 -4

The scope of the GALL Program XI.S4, provides two options for monitoring the performance of containment isolation valves. The applicant is requested to provide information regarding the applicant's choice of option for performing Type C testing during the period of extended operation.

Response

Ginna Station containment isolation valves are currently tested under 10 CFR 50, Appendix J, Type C, Option B, as required by Technical Specification 5.5.15. This testing methodology will be maintained during the period of extended operation.

F-RAI B2.1.3 -5

Section A2.1.3 of Appendix A (UFSAR Supplement) of the LRA summarizes the content the IWE and IWL AMP. However, it does not include the containment leak rate testing (i.e. GALL Report Section XI.S4) as part of the AMP. The applicant is requested to provide information regarding the inclusion of this aspect of the AMP in the UFSAR Supplement.

Response

A2.1.3 of Appendix A of the LRA should have addressed GALL Report Section XI.S4. The LRA is being supplemented by the following addition to Section A2.1.3 :
"This program also implements the requirements of 10 CFR 50, Appendix J. Containment leakage rates, in accordance with Option B of that regulation, through containment liner/welds, penetrations, and other openings are maintained within plant Technical Specification limits, or corrective actions are taken as required."

F-RAI B2.1.8 -1

Section B2.1.8, Buried Piping and Tank Surveillance Program, does not employ the guidance provided in the NACE Standards of RP-0285-95 and RP-0169-96 to manage the corrosion effect on the external surface of buried carbon steel piping and tanks. The guidance provided in the referenced NACE Standards are recommended in NUREG-1801 for implementing the surveillance and preventive measures to mitigate corrosion on the external surface of buried carbon steel piping and tanks. Instead, the AMP relies on the implementation of ten existing AMPs to maintain the intended functions of buried carbon steel piping and tanks.

a) Confirm and discuss whether this program is consistent with the guidelines provided in AMP XI.M28, "Buried Piping and Tanks Surveillance" of NUREG-1801. Discuss all the deviations from AMP XI.M28 and provide justification for each deviation.

b) For each buried piping and tank, describe what preventive and surveillance measures such as coating, wrapping, cathodic protection system or other protective measures are applied to mitigate corrosion of its external surfaces.

c) For each buried piping and tank, identify the applicable AMPs and discuss in detail how the applicable AMPs provide adequate protective and surveillance measures to mitigate the corrosion of its external surfaces.

d) Discuss in detail as how the ten referenced AMPs meet the guidance provided in NACE Standards RP-0285-95 and RP-0169-96 in providing adequate preventive and surveillance measures to mitigate corrosion of external surface of buried carbon steel piping and tanks.

e) Cathodic protection systems have been shown to be effective in mitigating corrosion of external surfaces of buried piping and tanks. Discuss the feasibility of implementing such protective system on the piping and tank components where adequate protective and surveillance measures are not applied.

f) In Section A2.1.7, "Buried Piping and Tanks Inspection," of the LRA it states that preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Describe the preventive measures that are applied and compare them to industry practice to determine their adequacy.

Response

The only buried tanks and piping in scope to license renewal are the emergency diesel fuel oil storage tanks, the TSC diesel fuel oil storage tank, fire-water piping, and sections of service water piping. As stated in the LRA, cathodic protection systems and NACE standards RP-0285-95 and RP-0169-96 are not employed at Ginna Station for aging management of buried piping and tanks. The buried environment at Ginna Station is considered benign.

a) The "A" and "B" diesel fuel oil storage tanks are carbon steel tanks with an external coal-tar mastic coating for protection from the buried environment. The tanks are set in sand and backfilled with sand. The interior surfaces of these tanks are cleaned and inspected periodically under the Periodic Surveillance and Preventive Maintenance Program. Visual inspections and ultrasonic thickness measurements are performed to verify tank wall integrity. No evidence of degradation has ever been detected by these inspections. These tanks are also pressure tested annually for verification of leak-tightness. The quality of diesel fuel oil in these storage tanks is verified periodically by the Diesel Fuel Oil Testing Program.

b) The TSC underground diesel storage tank was installed in 1980. The tank is a carbon steel tank with an asphaltic coal tar protective coating on the exterior surfaces. The tank is set in sand and backfilled with sand. During repair of mechanical damage to the vent pipe in 1998, the tank was excavated and an external visual inspection performed. The exterior condition of the tank was found to be in excellent condition. This tank is pressure-tested annually to verify leak-tightness.

c) The security diesel storage tank, although not in scope to license renewal, is also a buried tank similar in construction to the TSC diesel storage tank. The security diesel storage tank was dug up and replaced in 2000. Both the internal surfaces of the tank and the protective asphaltic coating on the exterior of the tank were found to be in excellent condition after 30 years of exposure to the buried environment. The quality of diesel fuel oil in the TSC diesel storage tank is verified periodically by the Diesel Fuel Oil Testing Program.

d) The fire water system piping at Ginna Station is cement-lined ductile cast iron with an external coating of coal tar for protection in the buried environment. Visual inspections and tests of fire water system piping are performed periodically under the One-Time Inspection Program and Fire Water System Program to verify that the intended functions of the fire water system are maintained. Test activities include fire pump full flow capacity tests, velocity flushes of piping and components, operability of hydrants and valves, and verification of the capability of the fire system to maintain pressure during performance tests. Visual inspections of the external and interior surfaces of piping and valves are performed during maintenance activities. Inspections to date have verified that the condition of buried fire water system components is excellent.

e) The service water supply and discharge piping at Ginna Station runs underground from the screen house to the turbine building. This piping is pre-stressed concrete. A remote visual inspection of the interior of approximately 500 feet of this piping was performed in 1994 under the Open Cycle Cooling Water Program. The condition of the pipe was excellent. The exterior of a portion of the concrete service water pipe was exposed and visually inspected during the construction of Diesel Generator Building in 1992. The exterior surface was found to be in excellent condition.

Review of plant-specific operating experience therefore confirms that the cathodic protection systems required by NUREG-1801, Section XI.M28, "Buried Piping and Tank Surveillance Program" are not necessary at Ginna Station for managing the effects of aging for buried tanks and piping in scope to license renewal.

F-RAI B2.1.16 -2

In Section B21.16, of the LRA it states that underground tanks have been drained and inspected annually until 1993. However, since 1993 only pressure tests are performed annually and internal inspections are performed on a 10-year frequency. Since decrease of the frequency of inspection may reduce the chances of detecting tank failure, provide the rationale for changing the inspection frequency of the underground storage tanks from annual to a 10-year frequency.

Response

The frequency of inspection of the underground diesel fuel oil storage tanks is based upon the recommendations of the manufacturer of the emergency diesel engines (Alco) and Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators". The inspection frequency for draining, cleaning, and inspecting the underground fuel storage tanks at Ginna Station is once every nine years. Based on the results of the inspections to be performed during the 2003 outage, the frequency will be re-evaluated as necessary.

F-RAI B2.1.18 -1

LRA Section B2.1.18 states that some inconsistencies were identified between crane operation and crane licensing basis at some plants in Bulletin 96-02, "Movement of Heavy Loads over Spent Fuel, Over Fuel in the Reactor Core, Over Safety-Related Equipment." Indicate whether or not any such inconsistencies have been identified at Ginna, either before or after the issuance of Bulletin 96-02. If inconsistencies were identified, provide the corrective actions that were taken.

Response

No inconsistencies were identified at Ginna Station. In our May 10, 1996 response to Bulletin 96-02, it was stated that "...all potential heavy load movements are within the scope of the Ginna Station licensing basis and are covered by existing plant procedures and work controls..."

The NRC's SER of April 23, 1998 agreed with this assessment.

F-RAI B2.1.18 -2

Clarify whether or not wire ropes are among the subcomponents that are managed for age related degradation. Provide the inspection methods and acceptance criteria for the wire ropes.

Response

As stated in Section 2.3.3.11 of the LRA, cables, hooks, and moving load-bearing elements used for transport of heavy loads are within the scope of License Renewal (see also RAI responses 2.3.3.11-1 and 2.3.3.11-2). Inspection methods and acceptance criteria are provided in Ginna procedure MHE-201, "Overhead and Gantry Cranes". These are visual inspections for evidence of wear, discontinuities, and any other signs of aging conducted by personnel qualified in accordance with procedure MHE-101, "Classification and Training of Material Handling Equipment Personnel".

F-RAI B2.1.21 -1

The LRA concludes that the One-Time Inspection Program will be consistent with GALL program XI.M32, "One-Time Inspection." A one-time inspection is generally appropriate for confirming the absence of significant aging effects. A review of the AMR tables in Section 3 of the LRA indicates that this program is being credited for items where aging is considered likely, such that a periodic inspection may be more appropriate than a one-time inspection. Justify why a one-time inspection is appropriate for the following: 1) change in material properties of Neoprene, 2) loss of material of cast iron and carbon steel in raw water, treated water (where One-Time Inspection is the only AMP), and drainage water, and 3) loss of heat transfer of cast iron in raw water.

Response

(1) One-time inspections of neoprene for changes in material properties are appropriate to confirm the absence of aging effects where the exposure temperature is below 95 degrees F and exposure to ionizing radiation is less than 1E6 rads (see response to RAI 3.4-6).

(2) Plant-specific operating experience indicates that gray cast iron exhibits good resistance to fresh (raw) waters such as Lake Ontario water (see response to RAI 3.4.9-1). Behavior of gray cast iron in drainage water would be expected to be equivalent to that in raw water, and equivalent or better in treated water. Therefore one-time inspections of gray cast iron components exposed to raw, treated and drainage water at Ginna Station would be appropriate to confirm the absence of aging effects.

(3) Loss of heat transfer of gray cast iron in raw water is an aging effect requiring management for the outboard bearing lube oil coolers in the Safety Injection (SI) Pumps and Auxiliary Feedwater Pumps. A discussion of the basis for performing a one-time inspection of these coolers, including information on the design of the coolers and plant-specific operating experience, is provided in the response to RAI 3.5-11.

(4) Table 3.4-2, line number (119), refers to the spent fuel cooling water heat exchangers. The shell side of these heat exchangers is carbon steel. The tube side is stainless steel. Spent fuel pool water flows through the tube side, and service water flows through the shell side. The Periodic Surveillance and Preventive Maintenance (PSPM) program should have been credited as an aging management Program for the shell-side components instead of the One-Time

Inspection Program. Eddy current inspections of the tubes are performed periodically as directed by the PSPM program. A combination of visual and ultrasonic inspections will be performed periodically on the shell side of these units.

(5) Table 3.4-2, line numbers (204) and (205) refer to carbon/low-alloy steel piping in the Treated Water System. The aging management program/activities are correctly identified as the Water Chemistry Control program, line number (205) and the One-Time Inspection program, line number (204) for verification of the effectiveness of the Water Chemistry Control program. Similarly, Table 3.4-2, line numbers (336) and (338) refer to the reactor make-up water tank, and the aging management programs/activities are correctly identified as the Water Chemistry Control program, line number (338) and the One-Time Inspection program, line number (336) for verification of the effectiveness of the Water Chemistry Control program. Likewise, Table 3.4-2, line numbers (388) and (390) refer to carbon/low alloy steel valves in the Treated Water System. The aging management programs/activities are correctly identified as the Water Chemistry Control program, line number (390) and the One-Time Inspection program, line number (388) for verification of the effectiveness of the Water Chemistry Control program.

F-RAI B2.1.21 -2

The staff finds that the UFSAR Supplement is generally consistent with the program description in Appendix B of the LRA; however, the UFSAR Supplement does not provide a level of detail commensurate with the SRP-LR. The applicant is requested to augment the UFSAR description to include the items in scope of the One-Time Inspection.

Response

Section A2.1.15 of the LRA is worded very similar to the wording in Table 3.4-2 of NUREG-1800, subsection "One-time inspection", though the Ginna One-Time Inspection program is meant to apply more broadly than implied by NUREG - 1800, for verifying the effectiveness of the Water Chemistry Program (see for example line number (42) in Table 3.3-2).
However, RG&E is augmenting the A2.1.5 description to provide additional detail. The second sentence of that paragraph should read : "The program methodology includes selection of appropriate inspection techniques, sample size, and locations (e.g., the internal surfaces of piping, valves, pump casings, heat exchangers, and tanks) to ensure that the specified age-related degradation will be discovered in a timely manner."

F-RAI B2.1.21 -3

Provide additional information on the construction (e.g., wrapped or protected), condition (any previous inspections), and environment of the buried fuel oil storage tank in the emergency power system.

The staff notes that the applicant does not credit a Buried Tank and Piping Inspection Program. Provide sufficient information to justify why a one-time inspection (ultrasonic wall thickness measurement), and periodic visual inspection of the tank internals under the Periodic Surveillance and Preventative Maintenance Program are adequate to manage aging of this tank.

Response

The emergency diesel generator (EDG) underground fuel oil storage tanks are 6000 gallon carbon steel tanks, 8 feet in diameter and 16 feet in length, with an exterior coating of coal tar mastic. The tanks were set in sand and backfilled with sand and secured in place with hold-down straps. Visual inspections of the interior surfaces of these tanks were performed every refueling outage since plant construction until 1994. Since 1994, the inspection interval has been every 9 years. The results of these inspections have indicated that the interior surfaces of the tanks are clean and free of corrosion. In addition to these inspections, annual leak-tightness tests are performed to verify tank integrity.

The tanks will be inspected again during the Fall 2003 refueling outage. These inspections will include both visual and ultrasonic thickness measurements of the tank walls at various locations, including the bottoms where water would be expected to accumulate. Ultrasonic thickness measurements of both underground storage tanks will be performed in the future under the Periodic Surveillance and Preventive Maintenance program at the same periodicity as the visual inspections.

F-RAI B2.1.21 -4

Provide information on the construction (e.g., wrapped or protected), condition (any previous inspections), and environment of the buried carbon steel pipe in the hydrogen detectors and recombiner system to justify using the One-Time Inspection program as the only aging management for this pipe.

Response

A short run of coated carbon steel pipe (approximately 18 inches) was installed between the primary hydrogen bottle house and the auxiliary building. This pipe was originally exposed. During the license renewal project system walk downs it was noted that the pipe is now partially in contact with engineered backfill. The backfill is not compacted and appears to have encroached on the pipe when the adjacent roadway was rebuilt in support of the 1996 Steam Generator Replacement project. The aging management activities associated with this pipe include removing the surrounding fill and performing a One-Time inspection to verify that the pipe has not suffered any corrosion effects. Omitted from the application was information that the pipe will subsequently be included in the Systems Monitoring Program. Table 3.4-2 line number (42) should also have included Systems Monitoring as an aging management program applicable to this pipe.

F-RAI B2.1.22 -3

The applicant identified that a number of heat exchangers have been replaced or retubed. Discuss the mechanisms leading to retubing or replacement, the means used to identify the degradation, if loss of pressure boundary integrity occurred and any changes made to the Open Cycle Cooling Water Program as a result of the degradation.

Response

The "A" and "B" Closed-Cycle Cooling Water (CCW) heat exchangers and the "A" and "B" emergency diesel generator (EDG) lube oil coolers and jacket water coolers are within the scope of license renewal and have been retubed at Ginna Station. The tubes in these heat exchangers are admiralty brass and are periodically inspected by eddy current testing under the Periodic Surveillance and Preventive Maintenance (PSPM) program as implemented by the Open Cycle Cooling Water (OCCW) System program. In all these units, service water (fresh Lake Ontario water) flows on the tube side. Degradation mechanisms identified by eddy current testing and verified by destructive metallurgical examination have included thinning due to erosion/corrosion, pitting and under-deposit corrosion, and limited OD fretting due to flow-induced vibration in the CCW units. Pitting and under-deposit corrosion developed during periods of stagnant or low-flow service. Tubes were removed from service by plugging based on conservative criteria. As a result of this practice, no loss of pressure boundary integrity has occurred in any of these heat exchangers. The heat exchangers were retubed with admiralty brass when the number of tubes plugged approached tube plugging limits. The EDG lube oil and jacket water coolers have been inspected every 18 months since 1996. The inspection intervals for the CCW heat exchangers have been adjusted from a 54-month frequency to a 36-month frequency based on the results of eddy current inspections.

The only heat exchangers within the scope of license renewal that are periodically replaced/refurbished are the lube oil coolers for the motor-driven and turbine-driven auxiliary feedwater pumps. These coolers are removed from service on a 3-year frequency, cleaned, eddy current inspected, and replaced in stock for reuse. The periodicity of the refurbishment activity is based on plant-specific operating experience related to tube-side fouling of these units. The tubes are stainless steel and no corrosion-related tube-wall degradation has ever been detected.

F-RAI B2.1.23 -4

The LRA states that aging effects such as loss of material, cracking, loss of seal, etc., are detected by visual inspection of surfaces for evidence of leakage, material thinning, accumulation of corrosion products, and debris. Under Program Description and Scope of Program, the LRA states that the program uses "visual inspections and surface examinations" to detect aging effects, while Detection of Aging Effects only discusses visual examinations, and Monitoring and Trending describes the use of periodic plant walkdowns (which implies visual external inspections) for monitoring the aging effects. The staff notes that this program is primarily used to detect internal aging of such AERMs as loss of material and cracking due to SCC. Clarify the type of inspections that are used to detect each of the aging effects covered by this program, and discuss their applicability to the AERMs being managed.

Response

The Periodic Surveillance and Preventive Maintenance (PSPM) provides for visual, surface and/or volumetric inspections of selected equipment items, structures and components (including fasteners) for evidence of age-related degradation on a specified frequency based on operating experience. Surface and/or volumetric examinations are utilized to supplement visual inspections as deemed necessary by engineering evaluation. Heat exchangers and coolers within the scope of license renewal are inspected under the PSPM program using volumetric techniques such as eddy current testing of tubing. Polymeric seals and gaskets in certain ventilation system components are periodically inspected for evidence of age-related degradation. Leak inspections of piping and components in selected portions of systems are also performed on a specified frequency. Periodic inspections required by the Open-Cycle Cooling (Service) Water System Surveillance program are also driven by repetitive tasks (reptasks) in the PSPM program and include a combination of visual, surface and volumetric techniques. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other aging management programs such as the Water Chemistry Control program.

Aging effects such as loss of material due to various corrosion mechanisms and wear are detected by visual examinations of surfaces for evidence of leakage, general or localized material thinning, presence of corrosion products, deposit accumulation, etc. Supplemental inspections using other NDE techniques such as surface (e.g., dye penetrant or magnetic particle) and volumetric (e.g., ultrasonic or radiographic) examinations are performed as necessary based on engineering evaluation. Change in material properties of polymeric seals and gaskets is detected by visual examination for evidence of cracking and crazing, evaluation of resilience and indentation recovery, evidence of swelling, tackiness, etc. Degradation of heat exchanger tubing is detected by eddy current testing, which provides the capability of detecting both ID and OD initiated tube-wall degradation such as thinning due to general, pitting and under-deposit (crevice) corrosion, MIC, fretting wear, fouling and cracking. Operations, maintenance, and surveillance test procedures and task descriptions will be enhanced to provide explicit guidance on detection of applicable aging effects and assessment of degradation.

The PSPM Program provides for monitoring and trending of material condition and equipment performance. PSPM activity intervals are established to provide timely detection of degradation and take into consideration known aging effects/mechanisms for material/service environment combinations as well as industry and plant-specific operating experience and manufacturers recommendations. The results of periodic surveillance inspections and preventive maintenance activities performed on selected equipment items are documented, evaluated, and trended.

F-RAI B2.1.23 -5

The LRA states that the One-Time Inspection Program (AMP B2.1.23) is used to verify the effectiveness of the Water Chemistry Control Program (AMP B2.1.37). The LRA further states that the One-Time Inspection Program is consistent with GALL Program XI.M32, "One-Time Inspection." A review of the LRA implies that the Periodic Surveillance and Periodic Maintenance Program is frequently used in lieu of the One-Time Inspection Program for verifying the effectiveness of the Water Chemistry Control Program. Clarify whether the Periodic Surveillance and Periodic Maintenance Program is being used for this purpose and, if so, discuss whether the inspections are comparable to the inspections GALL Program XI.M32.

Response

The Periodic Surveillance and Preventive Maintenance (PSPM) program is used for verification of the effectiveness of the Water Chemistry Control program. The inspections performed under the PSPM program are comparable to those performed under the One-Time Inspection program. The PSPM Program was selected as the inspection initiating activity when opportunities for inspection due to routine maintenance were identified. Where no such inspection opportunity was presented, the One-Time Inspection Program was credited.

F-RAI B2.1.23 -6

The LRA states that the inspection intervals are established to provide timely detection of degradation and are based on service environment as well as industry and plant-specific operating experience and manufacturers recommendations. In order to evaluate the acceptability of this program, the staff requires additional information on the frequency of inspections for the various AERMs covered by this program. Explain how the frequency of inspection was derived for the various AERMs covered by this program.

Response

The periodicity of many surveillance and preventive maintenance activities that were credited for license renewal was initially driven by considerations other than aging.

If a component in scope to license renewal was already included in the PSPM program due to industry or plant specific operating experience, the PSPM program was credited for aging management. A tracking mechanism was put in place to revise specific instructions in appropriate implementing procedures to include inspections for aging effects for each PSPM program activity. Based on the results of these aging management activities, inspection frequencies may be adjusted.

For components in chemistry-controlled or air/gas environments the effects of aging typically occur slowly over time. For example, an internal inspection of a check valve in the CCW system is more likely to be driven by seat/disc/hinge pin wear than by erosion or corrosion of the valve body. For components exposed to raw water environments, the periodicity of inspections is determined by trending data based on wall thickness measurements, corrosion product accumulation, fouling/biofouling build-up, etc. For heat exchangers, inspection frequencies are established by trending of tube wall degradation data. These trending evaluations have been effective in establishing frequencies which ensure that the effects of aging are managed such that intended functions of SSCs are maintained and will be maintained during the period of extended operation.

F-RAI B2.1.23 -7

The LRA states that acceptance criteria for this program "will be developed." Discuss how the criteria will be developed for each applicable AERM, and how this criteria, coupled with the inspection frequency, will ensure that the components continue to meet their LR intended function.

Response

Explicit guidance for detection of aging effects will be incorporated into all appropriate plant procedures that implement the Periodic Surveillance and Preventive Maintenance program for aging management purposes during the period of extended operation. This guidance will be developed using published technical reference and industry source material. Acceptance criteria for any degraded condition that is detected during inspections will be established by engineering evaluation of the degraded condition in accordance with the Ginna Station Corrective Action program. This evaluation will address the need for additional non-destructive inspections, changes in inspection frequency, as well as design Code requirements and margins.

F-RAI B2.1.23 -8

LRA Table 3.4-1, line number (2), indicates that the Periodic Surveillance and Preventive Maintenance Program will be used to address hardening, cracking, and loss of strength due to elastomer degradation for elastomers in the ventilation system. The LRA is unclear about how these items will be inspected. Describe the inspections that will be performed on the elastomers in the ventilation systems.

Response

As discussed in RAIs 2.1.23-1 and 2.1.23-4, change in material properties of elastomeric components in ventilation systems is evaluated by visual examination for evidence of cracking and crazing, evidence of swelling, tackiness, evaluation of resilience and indentation recovery, etc. Explicit guidance for detection of aging effects will be provided in the appropriate plant implementing procedures that govern these inspections.

F-RAI B2.1.23 -9

a) LRA Table 3.4-1, line number (9), states that Periodic Surveillance and Preventive Maintenance Program will be used to monitor for loss of neutron absorbing capacity and loss of material in neutron absorbing sheets in the spent fuel pool. The LRA is not clear how these items will be inspected. Describe the inspections that will be performed on the neutron absorbing sheets.

b) The existing evidence of the resistance of the neutron absorbing panels to degradation in the spent fuel pool environment is based on the results of one examination of a single coupon. Explain how these results are used for predicting capability of the neutron absorbers for performing their functions over the remaining life of the racks?

Response

a) The Periodic Surveillance and Preventive Maintenance Program directs the scheduling of activities to perform the testing needed to ensure the neutron absorber panels, constructed of borated stainless steel, maintain their safety function. The testing, performed as part of the Spent Fuel Neutron Absorber Monitoring Program, is described in Section B2.1.30 of the LRA.

b) The "Surveillance Program for Borated Stainless Steel Absorber Plates for the R.E.Ginna Spent Fuel Racks", procedure RE-8.4, uses a coupon tree consisting of thirty-six coupons, not a single coupon. The testing methodology was submitted to the NRC by letter dated October 10, 1997 for review as part of proposed License Amendment 72 (see particularly response to question 4), and was accepted per section 2.5.3 of the NRC's July 30, 1998 SER.

F-RAI B2.1.24 -1

The LRA indicates that the Protective Coatings Monitoring and Maintenance Program is not credited as a license renewal AMP, but has included a discussion of the 10 elements of an AMP "to demonstrate compliance with the resolution of generic safety issue (GSI) 191". After discussing the 10 elements the applicant concludes their Coatings Program is consistent with the GALL, but states the program is not credited for LR. GSI 191 is related to PWR sump clogging. Failed coatings are only one potential source of debris that could clog the sump. License Renewal is not the correct forum for resolving GSIs.

The staff requests that the applicant clarify the intent of providing the discussion on the Protective Coatings Monitoring and Maintenance Program and GSI 191 in the LRA.

Response

The purpose of the discussion in Section B2.1.24 was to show that even though Ginna Station does not credit external protective coatings for the purposes of aging management, the controls on coatings used inside containment are comparable to those described in the 10 program elements in NUREG-1801. This coatings maintenance program was described in our response to GL 98-04, dated 12/1/98, and accepted by the NRC in a letter dated 11/19/99.

Since GSI-191 is an unresolved issue, we agree that our current program's intent is not to demonstrate compliance with the resolution of that issue. That will be done within the current licensing basis arena.

F-RAI B2.1.25 -2

The LRA contains only a program description and Appendix A; the UFSAR does discuss this program. The applicant must identify whether all 10 elements of the program are in accordance with GALL Program XI.M.3 and whether the applicant's program contains any exceptions or enhancements to the 10 elements in GALL Program XI.M.3. The applicant is requested to describe this program in the UFSAR.

Response

As discussed in Section B2.1.25, "Reactor Head Closure Studs" is not a unique Ginna program, but the program elements are implemented by the programs described in B2.1.2, "ASME Section IWB,IWC,IWD Inservice Inspection" and B2.1.5, "Bolting Integrity". Within those descriptions, it is concluded that those programs are consistent with the attributes described in NUREG-1801 (and therefore the 10 elements are not discussed).

F-RAI B2.1.28 -1

Section B2.1.28 of the LRA indicates that an additional capsule will be withdrawn at a neutron fluence equivalent to approximately 52 EFPY of exposure. Items 5 through 7 in GALL XI.M31 provide recommendation for withdrawal of capsules during the period of LR.

a) Identify how the Ginna capsule withdrawal schedule for the period of LR complies with Items 5 through 7 in GALL XI.M31.

b) Provide the neutron fluence to be received by this capsule when it is removed from the vessel at a neutron fluence equivalent to approximately 52 EFPY.

c) Provide the calendar date at which time the capsule with be withdrawn.

Response

a) Ginna has surveillance capsules that have a projected fluence exceeding the 60 year fluence at the end of 40 years - thus, only item 6 applies.

b) Ginna has two surveillance capsules left in the core. Our current plan is to withdraw one of the capsules during the 2003 refueling outage. At that time, the capsule will have received a fast neutron fluence of 5.05E19, more than the projected dose at 60 years of 4.85E19. Since Ginna has performed, and submitted to the NRC, a reactor vessel equivalent margins analysis, we do not plan on testing that capsule (no need for Upper Shelf Energy values when an EMA has been performed).

c) Our current plan is to leave one capsule in the reactor vessel until about 2009, at which point it will have received a fast neutron fluence equivalent to 80 years of operation.

F-RAI B2.1.31 -2

Appendix "A" of the LRA contains a Supplement for the Ginna UFSAR. Supplement A2.1.22 describes the Steam Generator Tube Integrity AMP. This description did not indicate that the applicant has included (in the Steam Generator Tube Integrity AMP) aging management activities to address additional components, beyond those discussed in GALL, which are identified in Tables 3.2-1 and 3.2-2 of the LRA. In addition, the UFSAR Supplement did not identify any program specific details (i.e., inspection method, acceptance criteria, etc.) related to the additional components identified in Tables 3.2-1 and 3.2-2 of the LRA. This information must be added to the USAR Supplement in order to resolve this issue.

Response

As noted in response to RAI B2.1.31-1, this program should have been called the Steam Generator Integrity Program, since it manages more than the tubes, but also includes plugs, sleeves, and secondary side components.

Information regarding program details are provided in RAI reponse B2.1.31-1. The UFSAR Supplement is being modified to incorporate additional detail , as follows :

A2.1.22 Steam Generator Integrity

The program incorporates the guidance of NEI 97-06 and EPRI TR-107569 for maintaining the integrity of steam generator components, including tubes, sleeves, repair plugs, and secondary side components. Controlling primary and secondary water chemistry is the principal preventive action taken to prevent degradation. The effects of aging are managed by a balance of prevention, inspection, assessment, repair, and leakage monitoring measures. Eddy current testing performed in accordance with plant Technical Specifications detectsSG tube flaws caused by wall thinning, cracking, and mechanical damage or deformation. Secondary side visual inspections are performed to identify aging effects such as loss of material due to general, pitting and crevice corrosion, and fouling. Plant Technical Specifications assure timely assessment of tube integrity and compliance with primary - to- secondary leakage limits.

F-RAI B2.1.33 -1

The LRA states that the acceptance criteria for external corrosion will consider the design margin of the component being inspected. The staff notes that this program covers a wide variety of components, including metal expansion joints and pump bodies, that may have a wide range of design margin with respect to allowable corrosion. Provide additional information related to the acceptance criteria for the visual inspections with respect to how the design margin will be considered.

Response

The engineering guideline documents which implement the Systems Monitoring Program will be enhanced to provide specific guidance for detection of aging effects. This guidance will be developed using published technical reference and industry source material. Acceptance criteria for any degraded condition that is detected during inspections will be established by engineering evaluation of the degraded condition in accordance with the Ginna Station Corrective Action Program. This evaluation will address the need for additional non-destructive inspections, as well as design Code requirements and margins.

Attachment 3: FRAI 4.7.5-1 response

# Containment Overhead Handling Systems Data for TLAA Evaluation

Attachment to DA-CE-2002-016-03

| No. | Overhead Handling System | Capacity (Tons) | °EIN | Crane Service Classification | Design Loading Cycles | Loads Lifted | Heaviest Load Lifted (lbs) (Approximate) | Frequency Lifted | Year Installed | Estimated Loading Cycles from Installation to 2029 (Note 1) | Basis for Anticipated Cycles and/or Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Containment Jib Crane at Equipment Hatch | 3 | CJCRC04 | B^ | 20,000 to 100,000 | Welding Machines, Ancillary Equip. | 400 | (300) 2 times per Refueling | 1972 | 31,200 | Used extensively for loading and unloading Equipment at start and end of Refueling outages. |
| 2 | Containment Jib Crane over "A" RCP | 1 | CJCRC05 | B^ | 20,000 to 100,000 | Oil Lift Pump, Ancillary Equip. | 325 | (10) 2 times per Refueling | 1972 | 1040 | Procedure Series M-11.8 |
| 3 | Containment Jib Crane over "B" RCP | 1 | CJCRC06 | B^ | 20,000 to 100,000 | Oil Lift Pump, Ancillary Equip. | 325 | (10) 2 times per Refueling | 1972 | 1040 | Procedure Series M-11.8 |
| 4 | Containment Fuel Manipulator Bridge Crane | 3 | CFHRC02 | B^ | 20,000 to 100,000 | Fuel Assemblies | 2000 | (42) 221 per Refueling (Fs) (10) 242 per Fueling (Co) | Original | 11,702 | RF 65.2 Section 1.2.1 Load Cell Overload Set at 2000# |
| 5 | Auxiliary Hoist on Fuel Manipulator Bridge | 1.5 | CRHRC02 | B^ | 20,000 to 100,000 | Hand Tools | 300 | (10) 2 times per Refueling | 1972 | 1040 | |
| 6 | Pressurizer Jib Crane | 10 | CJCRC08 | B^ | 20,000 to 100,000 | Reinforced Concrete Pressurizer Hatchcovers | 9600 | 3 -- 2x's at Refueling | Original | 312 | |
| 7 | Containment Main Overhead Crane | 100/20 | COHRC01 | A* | 20,000 to 100,000 | RCP Parts (Aux Hook) | 4,000 | 2 times per Refueling | Original | 104 | Motor Stand @4000# Procedure Series M-11.8 |
| | | | | | | Upper Internals (Main Hook) | 53,000 | (42) 2 times per Refueling (10) 4 times per Refueling+ | Original | 124 | RF Procedure 65.1 Sections 1.1.2 and 1.2.16 |
| | | | | | | RPV Head (Main Hook) | 188,550 | (42) 2 times per Refueling (10) 4 times per Refueling+ | Original | 104 | RF Procedure 65.1 Section 1.2.13 "R.V. Head Lift Rig Analysis" used for weight, W WCAP-10099 |
| | | | | | | Lower Internals (Main Hook) | 202,000 | 2x's per 10 years | Original | 12 | RF Procedure 65.3 Section 1.21.1 "RV Internals Lift Rig Stress Analysis" used for Weight, W WCAP-10099 |
| | | | | | | Floor Sections (Aux Hook) | 18,000 | 9 -- 2x's at Refueling | Original | 936 | Conservatively includes 3 sets of blocks: Crane Bay, RCP "A", RCP "B" |
| | | | | | | RCP Motor (Main Hook) | 81,000 | 2x's per Every Other Refueling | Original | 52 | Procedure M-11.8 W WCAP-10099 "R.C. Pump Motor Lift Sling" Design Analysis for Weight |
| | | | | | | Misc. Loads to Support Refueling Gang Boxes. Stud Racks, Tools, Equipment Parts | 20,000 Max Most Loads <5000 | (150) 2x's per Refueling | Original | 15,600 | |
| 8 | Containment Jib Crane at Personnel Hatch | 2 | CJCRC07 | B^ | 20,000 to 100,000 | Ancillary Equip. | 4000 Max. | (3) 2x's per Refueling | 1972 | 312 | JIB is seldom used due to its location. |
| 9 | Jib on Overhead Crane (Northeast End) | 0.25 | COHRC01 | B^ | 20,000 to 100,000 | Tools and Equipment for Crane Inspections | 500 Max. | (1) 2x's per Refueling | Original | 104 | Not aware of this ever being used. |
| 10 | 3 Hoists on Reactor Head Monorail | 1 | CMRRC11 | B^ | 20,000 to 100,000 | (48) RPV Head Studs by 3 Hoists | 400 | (16) 2x's per Refueling | Original | 1664 | RF Procedure 65.1 Reactor Vessel Disassembly |
| 11 | Jib on Overhead Crane | 0.5 | COHRC01 | B^ | 20,000 to 100,000 | Crane Parts | 1000 Max. | (1) 2x's per Refueling | Early Plant Mod. | 104 | Used during 1995 SGR (N-1 Outage). Other than that not used. |
| 12 | Containment Enclosure Monorail | 4 | CMRRC09 | B^ | 20,000 to 100,000 | Misc. Tool Boxes and Equipment | 8000 Max. | (10) 2x's per Refueling | Original | 1040 | Monorail is very seldomly used. Ctmt loading and unloading done using fork trucks |
| 52 | Containment Jib Crane on Wall by Charcoal Filter Plenums | 1 | CJCRC09 | B^ | 20,000 to 100,000 | Welding Machines, Ancillary Equip. | 400 | (200) 2x's per Refueling | 2000 | 8,000 | Newly installed in 2000, this crane used extensively to load and unload Ctmt. |

°Crane ID from RG&E Dwg 03021-0395

* Classification taken directly from Requirement Outline.

^ Classification selected from CMAA based on use.

+ Extra movements required for full core offload maintenance activities

FS - Fuel Shuffle

CO - Core Offload

NF - New Fuel

Note 1: Total Refueling Outages through 2000 = 32

Total Anticipated Refueling Outages from 2001 to 2029 = 20

(At 18 Month Cycles)

# Auxiliary Building Overhead Handling Systems Data for TLAA Evaluation

| ° | Overhead Handling System | Capacity (Tons) | EIN | Crane Service Classification | Design Loading Cycles | Loads Lifted | Heaviest Load Lifted (lbs) (Approximate) | Frequency Lifted | Year Installed | Estimated Loading Cycles from Installation to 2029 (Note 1) | Basis for Anticipated Cycles and/or Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | Auxiliary Building Spent Fuel Pool Crane | 2 | CFHAB02 | B^ | 20,000 to 100,000 | Fuel Assemblies | 1500 | 100 per Cycle<br>2 Reracks @1000 Each<br>1 Boraflex Mod @ 1000<br>(10) 242 per Refueling<br>(88) New/Old Assemblies per Cycle | Original | 5200<br>2000<br>1000<br>2420<br>4576<br>Total = 15,196 | |
| | | | | | | BPRA Handling Tool | 800 | (92) Per Refueling | Original | 1840 | 1990 - 1970 = 20 Yr, Not Used Any More |
| | | | | | | Flow Mixing Tool | 300 | (92) Per Refueling | Original | 1840 | 1990 - 1970 = 20 Yr, Not Used Any More |
| 29 | Auxiliary Building Main Overhead Crane | 40/5 | COHAB01 | C* | 100,000 to 500,000 | RHR Pumps (Aux Hook) | 4600 | 2x's per 5 years | Original | 24 | |
| | | | | | | Component Cooling Pumps (Aux Hook) | 2308 | 2x's per 5 years | Original | 24 | |
| | | | | | | RCDT Pumps (Aux Hook) | 300 | 2x's per year | Original | 120 | |
| | | | | | | Removable Floor Section (Aux Hook) | 4800 | 2x's per year | Original | 120 | |
| | | | | | | New Fuel Assemblies (Aux Hook) | 1260 | 120x's per year | Original | 7200 | |
| | | | | | | New Fuel Shipping Cask (Aux Hook) | 6500<br>EW 4000 | 16 per year | Original | 960 | |
| | | | | | | Steam Generator Tools (Aux Hook) | 1250 | 4x's per year | Original | 240 | |
| | | | | | | Transfer Canal Gate (Aux Hook) | 1800 | 2x's per year | Original | 120 | |
| | | | | | | Lead Basket (Aux Hook) | 1500 | 2x's per year | Original | 120 | |
| | | | | | | Miscellaneous Ancillary Equipment | 10,000 Max. Most Loads <1000 | 100 per year | Original | 5200 | |
| | | | | | | Spent Fuel Shipping Cask (Main Hook) | 50,000 | Spent Fuel Sent to West Valley 15 Casks Out, 15 Casks Back | Original | 30 | |

oCrane ID from RG&E Dwg 03021-0395

* Classification taken directly from Requirement Outline.
^ Classification selected from CMAA based on use.
\+ Extra Movements Required for Full Core Offload Maintenance Activities

Note 1: Total Refueling Outages through 2000 = 32
Total Refueling Outages from 2001 to 2029 = 20
(At 18 Month Cycles)

# THIS PAGE IS AN OVERSIZED DRAWING OR FIGURE,

## THAT CAN BE VIEWED AT THE RECORD TITLED: GINNA STATION AC ELECTRICAL SYSTEM, ONE LINE WIRING DIAGRAM, DWG.NO LR33013-2409

## WITHIN THIS PACKAGE...OR, BY SEARCHING USING THE DWG NO:LR33013-2409

**NOTE: Because of this page's large file size, it may be more convenient to copy the file to a local drive and use the Imaging (Wang) viewer, which can be accessed from the Programs/Accessories menu.**

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