NEXTera ENERGY DUANE ARNOLD

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U.S. Nuclear Regulatory Commission
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Washington, DC 20555-0001

Duane Arnold Energy Center
Docket 50-331
License No. DPR-49

Response to Request for Additional Information Regarding the Review of the License Renewal Application for Duane Arnold Energy Center

References:

1. Letter, Richard L. Anderson (FPL Energy Duane Arnold, LLC) to Document Control Desk (USNRC), "Duane Arnold Energy Center Application for Renewed Operating License (TSCR-109)," dated September 30, 2008, NG-08-0713 (ML082980623)

2. Letter, Richard L. Anderson (FPL Energy Duane Arnold, LLC) to Document Control Desk (USNRC), "License Renewal Application, Supplement 1: Changes Resulting from Issues Raised in the Review Status of the License Renewal Application for the Duane Arnold Energy Center," dated January 23, 2009, NG-09-0059 (ML090280418)

3. Letter, Brian Harris (USNRC) to Christopher Costanzo (Florida Power & Light Company), "Request for Additional Information for the Review of the Duane Arnold Energy Center License Renewal Application (TAC No. MD9769)," dated September 14, 2009 (ML092310358)

By Reference 1, FPL Energy Duane Arnold, LLC submitted an application for a renewed Operating License, including an Environmental Report. A supplement to the application was submitted by Reference 2. By Reference 3, the U.S. Nuclear Regulatory Commission (NRC) Staff requested additional information regarding the License Renewal Application for the Duane Arnold Energy Center. The enclosures to this letter contain the NextEra Energy Duane Arnold, LLC, (f/k/a FPL Energy Duane Arnold, LLC) responses to the Staff's requests for additional information.

Enclosure 1 provides responses to the Requests for Additional Information (RAIs) of Reference 3. An index of the RAIs addressed in the enclosure is provided for ease of retrieval.

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Enclosure 2 provides a revised LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, updated to reflect the commitment changes made in DAEC correspondence to date.

This letter contains five new license renewal commitments and changes to nineteen existing license renewal commitments, as noted in the RAI responses and Enclosure 2.

If you have any questions or require additional information, please contact Mr. Kenneth Putnam at (319) 851-7238.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 13, 2009.

Christopher R. Costanzo
Vice President, Duane Arnold Energy Center
NextEra Energy Duane Arnold, LLC

Enclosures:
1. Responses to Requests for Additional Information
2. Updated Table A-1 Duane Arnold License Renewal Commitments

cc: Administrator, Region III, USNRC
Project Manager, DAEC, USNRC
Senior Resident Inspector, DAEC, USNRC
License Renewal Project Manager, USNRC
License Renewal Inspection Team Lead, Region III, USNRC
M. Rasmusson (State of Iowa)

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RAI LRA Table 3.4.2-4

Background

Accurate identification of material and environment combinations, as described in the GALL report (NUREG-1801), is necessary to support AMRs.

Issue

LRA Table 3.4.2-4 "Summary of Aging Management Review Results Main Steam Isolation and Automatic Depressurization System" describes stainless steel Pipe, pipe fittings, hoses, tubes, rupture disk with an internal steam environment. During the material/environment verification audit walkdown, the NRC staff requested that the applicant show examples of component(s) that included tubing with steam environment, hoses with steam environment and rupture disk with steam environment. The applicant showed an example of an instrument tube line that was not thermally insulated (lagged) and would appear, based on a dead leg tap from a steam line, to contain condensate rather than steam. In addition when asked to follow up on examples for hose material in a steam environment, the applicant referred to a valve stem leak off pipe indicated on the drawing as flexible, but was not considered a "hose," either on the drawing or in the applicant's equipment data base. Lastly, the applicant referred to a rupture disk, a device "in scope", but in discussions, confirmed that these components were screened out as short lived components not requiring an AMR and therefore should not have been included in Table 3.4.2-4.

Request

Provide the documentation to show that there are specific examples of these component types with material/environment described, or correct the material environment description in Table 3.4.2-4. In addition, describe how the generic component and environment types were verified to ensure specific plant components are accurately represented in the Summary of AMR Results submitted in the DAEC license renewal application.

DAEC Response to RAI B.3.4.2-4

The general component type description, "Pipe, pipe fittings, hoses, tubes, rupture disk," that is used for certain piping assets in most of the LRA 3.x.2 tables, is a generic grouping that represents many specific components, including, potentially, some in addition to the ones listed. This grouping of components in the DAEC LRA is similar to the NUREG-1801 component grouping "Piping, piping components, and piping elements." NUREG-1801 Table IX.B, "Selected Definitions & Use of Terms for Describing and Standardizing STRUCTURES AND COMPONENTS," defines its grouping, "Piping, piping components, and piping elements," as follows:

> This general category includes various features of the piping system that are within the scope of license renewal. Examples include piping, fittings, tubing, flow

elements/indicators, demineralizer, nozzles, orifices, flex hoses, pump casing and bowl, safe ends, sight glasses, spray head, strainers, thermowells, and valve body and bonnet. For reactor coolant pressure boundary components in Chapter IV that are subject to cumulative fatigue damage, this can also include flanges, nozzles and safe ends, penetrations, vessel head, shell, welds, stub tubes and miscellaneous Class 1 components, such as pressure housings.

In a manner similar to NUREG-1801, the DAEC grouping, "Pipe, pipe fittings, hoses, tubes, rupture disk," represents many specific components or features of a piping system. When this general component type description is used in a 3.x.2 table, it does not suggest that every specific item in the group name is in the particular 3.x.2 table line item of interest. It only indicates that the table line item addresses at least one item that falls within the group. Accordingly, every specific item in the group "Pipe, pipe fittings, hoses, tubes, rupture disk" will not be present in every 3.x.2 table line item that uses this group name. Similarly, there will often be many more specific components represented by the table line item in addition to the five example items that comprise the group name.

At DAEC, scoping and screening were performed on an individual component basis. Components in scope for license renewal were then consolidated into groups such as "Pipe, pipe fittings, hoses, tubes, rupture disk" for aging management review and reporting at a summary grouping level in the 3.x.2 tables of the LRA. This approach to reporting the results of the aging management review is consistent with the guidelines of NEI 95-10.

With respect to the specific concern regarding the assignment of steam or treated water as the applicable environment for a certain Main Steam System component, the terms are equivalent in practice and the result of the aging management review would be the same. For the DAEC aging management reviews, treated water and steam environments were given a common environment name, "Treated Water and/or Steam" and a common definition, as follows:

> Treated Water is demineralized water or chemically purified water and is the base water for all clean systems. Depending on the system, treated water may require further processing. Treated water can be de-aerated, can include corrosion inhibitors, biocides, or sodium pentaborate, or can include a combination of treatments. Steam generated from treated water is included in this category.

A common environment definition for treated water and steam for the Main Steam and Feedwater Systems, among others, is reasonable because the aging effects applicable to these treated water and steam environments are the same.

A review of Table 3.4-1, Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL Report, in both NUREG-1800 and the DAEC LRA, revealed that the identified aging effects and aging management programs are the same for steel in treated water and steam and for stainless steel in treated water and steam. The following table illustrates how the aging management results are identical in Table 3.4-1 of both the SRP and the DAEC LRA treatment of steam and treated water environments for steel and stainless steel in the Main Steam, Feedwater, and other Chapter VIII Systems. Therefore, for the example cited, an instrument line that could have condensate as well as steam, it makes no difference whether steam or treated water is listed as the environment in Table 3.4.2-4, because the aging management review would define the same aging effects requiring management and the same aging management programs for either steam or treated water.

Material	Environment	Applicable Table 3.4-1 Line Items	Aging Effect / Mechanism	Aging Management Program
Steel	Treated Water or Steam	3.4.1-1	Cumulative fatigue damage	TLAA
Steel	Treated Water or Steam	3.4.1-29	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion
Steel	Treated Water	3.4.1-4	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time inspection
	Steam	3.4.1-2	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time inspection
Stainless Steel	Treated Water >140 degF	3.4.1-14	Cracking due to stress-corrosion cracking	Water Chemistry and One-Time inspection
	Steam	3.4.1-13	Cracking due to stress-corrosion cracking	Water Chemistry and One-Time inspection
Stainless Steel	Treated Water	3.4.1-16	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time inspection
	Steam	3.4.1-37	Loss of material due to pitting and crevice corrosion	Water Chemistry

RAI 4.3.1-1

Background

LRA Section 4.3.1 states that in 1998 DAEC performed re-assessment of DAEC RPV to remove excess conservatism from the existing fatigue calculations for all RPV components, and to incorporate transient cycles projected to occur at 40 years based on actual plant operation as of that time.

Issue

It is not clear to the staff what difference was between the cumulative usage factor (CUF) of the original design values and the reassessed values. The staff was unable to find CUF results reported in the UFSAR.

Request

1. Provide a side-by-side comparison of the CUF of the original design values and the reassessed values for the components identified in LRA Table 4.3-2.
2. Describe the conservatisms that were removed for the 1998 reevaluation.
3. Provide justification that some locations in LRA Table 4.3-2 are exempted for fatigue evaluations.
4. Confirm that the CUF values shown in LRA Table have accounted for the extended power uprate (EPU) operating conditions.

DAEC Response to RAI 4.3.1-1

Part 1
The comparison of original design (Chicago Bridge & Iron - CB&I) CUF values with the 1998 reassessment is provided in the Table below.

Location	**CB&I 40 year CUF**	**1998 Reassessment 40 year CUF**	**Comments**
Main Closure Studs	0.834	0.882	
Main Closure Flanges	Exempted	Exempted	
Skirt to Head Junction	0.0267	0.0337	
Shroud Support Pt. 21 Pt. 19 Pt. 42 Pt. 44	 0.97 0.086 0.316 0.33	 0.773 0.090 0.320 0.336	

Location	**CB&I 40 year CUF**	**1998 Reassessment 40 year CUF**	**Comments**
<u>Feedwater Nozzle</u> Forging Safe End Pts 1-6,10-16 Thermal Sleeve Pt. 7 Thermal Sleeve Pt. 8 Safe End Pt. 9	 Exempted 0.898 0.847 0.754 0.539	 Exempted 0.578 0.639 0.506 0.778	
<u>CRD Penetration</u> Housing Stub Tube Vessel Wall Stub tube-to-RPV Weld RPV Wall Contour Grinding	 Exempted Exempted Exempted 0.066* 0.147**	 Exempted Exempted Exempted 0.106 N/A	*The original CB & I report misread a fatigue curve and incorrectly reported CUF as 0.66. **1998 reassessment did not evaluate contour grinding location (appears to have been "missed.")
<u>CRD-HSR Nozzle</u> Safe End Forging	 0.825 Exempted	 1.0 Exempted	
CS Nozzle (Cladding)	0.592	0.735	
Recirc Inlet Forging Safe End	 Exempted 0.150***	 Exempted 0.438	***Original CB & I reported CUF of 0.515. Replacement Safe End Stress Report value is 0.150.
Recirc Outlet	0.705	0.975	
Steam outlet	Exempted	Exempted	
Misc nozzles	Exempted	Exempted	
Refueling Bellows Support	0.280	0.580	

<u>Part 2</u>

As seen in the Table, the CUFs determined for certain locations in the 1998 reassessment are less than the CUFs reported in the original CB & I report; for example, Shroud Support Pt 21 and certain Feedwater Nozzle locations. Further discussion regarding these reductions in conservatism follows.

For Shroud Support Pt 21, the original CB & I analysis assumed that the transient event which produces the largest alternating stress range (loss of feedwater transient) was applicable to all cycles (including hydrotest, startup/shutdown, etc.) whose alternating stress intensity range was less). The 1998 reassessment determined the alternating stress intensity for the hydrotest and used it to determine the usage factor for the hydrotest cycles. The alternating stress intensity for the loss of feedwater transient was applied to the remaining cycles (including startup/shutdown, etc.), and the fatigue usage was found by using Miner's Rule. Note that although conservatism was reduced, the evaluation still contained added conservatism, as the larger alternating stress intensity was still applied to more cycles than just the loss of feedwater.

For the Feedwater Nozzle, the 1998 reassessment reduced conservatism in the calculation of skin stress. In the original fatigue analysis of the feedwater nozzle, the peak skin stress was calculated from the following equation:

$$\sigma = S_1(E\alpha\Delta T)/(1-\nu).$$

The value used for S_1 was 0.7. The 1998 reassessment determined a more realistic estimate of S_1 by using the Biot modulus. This resulted in a value of S_1 of 0.5, which resulted in a lower stress range and lower CUF.

Part 3

Section III of the ASME Code allows that a fatigue analysis is not required if all of the requirements of Par. N-415.1 are satisfied. The requirements are outlined below. Those locations that are listed as "Exempted" in LRA Table 4.3-2 meet these requirements.

Pressure Cycles

Subparagraph (a) of N-415.1 requires that the number of times that the pressure will be cycled from atmospheric pressure to operating pressure and back to atmospheric pressure does not exceed the number of cycles on the fatigue curve corresponding to an S_a value of 3 times the S_m value for the material at operating temperature.

Pressure Fluctuations

Subparagraph (b) of N-415.1 requires that the full range of pressure fluctuations during normal operation does not exceed the quantity (1/3) x design pressure x (S_a/ S_m) where S_a is the value obtained from the applicable design fatigue curve for the total specified number of significant pressure fluctuations. Significant pressure fluctuations are those for which the total deviation from "normal" operating pressure exceeds the quantity (design pressure) x 1/3 x (S/S_m), where S equals the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

Temperature Differences

Subparagraph (c) of N-415.1 requires that the temperature difference in °F between any two adjacent points on the vessel during normal operation and during startup and shutdown does not exceed $S_a/(2E\alpha)$, where S_a is the value obtained from the applicable design fatigue curve for the total number of startup-shutdown cycles.

Temperature Difference Fluctuations

Subparagraph (d) of N-415.1 requires that the temperature difference in °F between any two adjacent points of the vessel does not change during normal operation by more than the quantity $S_a/(2E\alpha)$, where S_a is the value obtained for the total specified number of significant temperature-difference fluctuations. A temperature difference fluctuation shall be considered to be significant if its total range exceeds the quantity $S/2E\alpha$, where S is the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

Temperature Fluctuations

Subparagraph (e) of N-415.1 requires that for components fabricated from materials of differing moduli of elasticity and/or coefficients of thermal expansion, the total algebraic range of temperature fluctuation experienced during normal operation does not exceed the quantity $S_a/2(E_1\alpha_1 - E_2\alpha_2)$, where S_a is the value obtained from the applicable design fatigue curve for the total specified number of significant temperature fluctuations. A temperature fluctuation shall be considered to be significant if its total excursion exceeds the quantity $S/2(E_1\alpha_1 - E_2\alpha_2)$, where S is the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

Mechanical Loads

Subparagraph (f) of N-415.1 requires that the specified full range of mechanical loads, excluding pressure but including pipe reactions, does not result in load stresses whose range exceeds the S_a value obtained from the applicable design fatigue curve for the total specified number of significant load fluctuations. A load fluctuation shall be considered to be significant if the total excursion of load stress exceeds the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

<u>Part 4</u>

The 60 year CUFs provided in LRA Table 4.3-2 include the effects of EPU. As discussed in the response to RAI B.4.2-2, the evaluation of 60 year CUFs took into account the 1998 reassessment and power uprate evaluations, as well as the impact of other evaluations, such as the revised fatigue evaluation for the main closure region referenced in LRA Section 4.3.1.

RAI 4.3.1-2

Background

LRA Section 4.3.1 states that the transient cycle projections were made using forward projection methodology that uses trending from 1998 through 2005 time period of plan operation. Furthermore, the applicant indicates that for selected events, additional conservatism was added beyond the mathematically projected number of cycles to accommodate potential variation in plant performance late in plant life, as well as to allow for additional events where the projected number of cycles was very low and the likelihood of additional events could not be ruled out.

Issue

Seven-year as basis for making long-term transient cycle projection does not seem sufficient. In addition, it is not clear what conservatism has been used in the cycle projections.

Request

1. Provide justification that cycle projections based on the most recent 7 years of plant data is adequate.
2. Describe the conservatism exercised in the cycle projections and quantify as much as possible.

DAEC Response to RAI 4.3.1-2

Part 1

The cycle projections were based on trending from the 1998 through 2005 time period of plant operation. This time period corresponds to the time during which data were available from the surveillance/test procedure (STP). (Note that the evaluation was started prior to completion of the STP during the 2007 refueling outage (RFO); therefore, the data from the 2005 STP performance were used to develop the trend.) As shown in the example provided in the response to Part 2 below, the projections were not based solely on this trending. Industry and plant experience were also taken into consideration to ensure that the numbers of cycles used in the 60-year evaluations were appropriate.

Part 2

To determine the number of transient cycles that should be assumed in the 60 year fatigue calculations, projections were based on a forward projection methodology using trending from the 1998 through 2005 time period of plant operation. This time period corresponds to the time during which data were available from the STP. (Note that the evaluation was started prior to completion of the STP during the 2007 RFO; therefore, the data from the 2005 STP performance were used to develop the trend.)

Transient counts were projected forward to 60 years of plant operation, using the following relationship:

$N_{60} = N_{2005} + [(N_{2005} - N_{1998}) / Time_{1998\ to\ 2005}] * Time_{2005\ to\ 2034}$

where:

N_{60} = the projected number of cycles for 60 years of operation.
N_{1998} = the number of cycles experienced as of RFO 15 (assumed to be 4/1/1998).
N_{2005} = the number of cycles experienced as of RFO 19 (4/25/2005), which was the latest cycle count information at the time the evaluation was started.
$Time_{1998\ to\ 2005}$ = elapsed time from RFO 15 cycle counts (4/1/1998) to the date of the most recent cycle counts (4/25/2005).
$Time_{2005\ to\ 2034}$ = elapsed time from most recent cycle counts (4/25/2005) to the end of 60-year operating period (2/22/2034).

Substituting the pertinent information regarding scrams results in:

$N_{60} = N_{2005} + [(N_{2005} - N_{1998}) / Time_{1998\ to\ 2005}] * Time_{2005\ to\ 2034}$
$N_{60} = 110 + [(110-108) / 7.07] * 28.83 = 119$ (rounded up)

Additional conservatism is provided by increasing the number of scram cycles for 60 years from 119 cycles calculated above to 150 cycles.

Conservatism was also applied with regard to those transients for which the methodology discussed above would have yielded zero cycles (for example, the "sudden start of pump in cold recirc loop"). No cycles of this transient have been recorded, so the use of the above methodology would result in a 60-year number of zero; a conservative assumption of 2 cycles was used for the 60-year evaluation instead.

RAI 4.3.1-3

Background

LRA Table 4.3.1 shows the transients and cycles used for the CUF calculation as well as the cycles accrued over the past 30 some years, and 60-year cycle projections.

Issue

The transients shown in LRA Table 4.3-1 are not the same as those shown in UFSAR Table 5.3-7.

Request

1. Provide justification that the transients and number of cycles defined in LRA Table 4.3-1 is acceptable when it is distinct from those defined in the UFSAR.
2. Provide justification that the CUF of the original design analyses can be used as the basis for making CUF projections now since the transients used for license renewal are different from those constitute the current licensing basis.

DAEC Response to RAI 4.3.1-3

Part 1

Table 5.3-7 was revised in UFSAR Revision 20 (2009), as part of the corrective actions taken to resolve discrepancies between the 1998 fatigue reassessment and the power uprate fatigue evaluation discussed in LRA Section 4.3.1. The 40-year cycle numbers in LRA Table 4.3-1 and UFSAR Table 5.3-7 are now in agreement, with one exception. Table 4.3-1 lists 3 cycles for hydrostatic test (125% design hydro pressure test), while UFSAR Table 5.3-7 lists 2 cycles, with a note that one of the design documents lists 3 cycles. This difference is inconsequential, since only one test has been performed and the 125% test is no longer done.

The transients listed in LRA Table 4.3.1 agree with UFSAR Table 5.3-7 with the exception of "CRD isolation" and "Single CRD scram." While these two transients are not listed in Table 4.3.1, they are used in the determination of the fatigue results for 40 and 60 years that are listed in Table 4.3-2. Note that these transients apply to the evaluations for the CRD penetration (Housing, Stub Tube, Vessel Wall, Stub tube-to-RPV Weld, and RPV Wall Grinding) locations.

Part 2

The CUFs from the original design analyses were not the sole basis for making the 60-year CUF determinations. Pertinent input from later fatigue evaluations, including the 1998 fatigue reassessment and power uprate, were taken into account in the evaluation of fatigue for 60 years.

Also, as discussed above, the transients used in the determination of fatigue for 60 years are consistent with those contained in the revised UFSAR Table 5.3-7. Therefore, the 60 year CUFs have been evaluated using appropriate bases.

RAI 4.3.2-1

Background

LRA (Supplement 1) Section 4.3.2 states that no fatigue analysis of the entire reactor vessel internals (RVI) was performed because the DAEC RVI is not Class 1 pressure boundary components, except for the shroud support, which is considered part of the vessel.

Issue

Even though being non-pressure boundary components, Class 1 components are subject to fatigue requirements. For old vintage plants, there may be cases where explicit fatigue usage evaluation are not required, Reactor Vessel Internals were implicitly designed for low cycle fatigue based upon the reactor coolant system design transient projections for 40 years.

Request

Provide basis to justify why fatigue requirements are not addressed for the RVI components except for the shroud support.

DAEC Response to RAI 4.3.2-1

10 CFR 54.3 defines TLAAs as those licensee calculations and analyses that (1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a); (2) Consider the effects of aging; (3) Involve time-limited assumptions defined by the current operating term, for example, 40 years; (4) Were determined to be relevant by the licensee in making a safety determination; (5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and (6) Are contained or incorporated by reference in the CLB. Therefore, to be considered a TLAA, the analysis must be contained in the current licensing basis (CLB).

A review of the DAEC CLB did not identify a fatigue evaluation performed for the RPV internals. As stated in LRA Section 4.3.2, the shroud support is considered part of the vessel; fatigue was, therefore, evaluated for the shroud support as a TLAA.

RAI 4.3.3-1

Background

LRA (Supplement 1) Section 4.3.3 states, "A fatigue analysis exemption evaluates an envelope of material, temperature, pressure and mechanical load parameters (relative to the instrument piping design data) against the conditions stipulated in the Code to demonstrate that analysis for cyclic operation is not required".

Issue

Clarification is necessary to enable the staff to make its review.

Request

Describe the criteria used by the "fatigue analysis exemption evaluation" to exempt locations from fatigue analysis.

DAEC Response to RAI 4.3.3-1

Section III of the ASME Code contains a provision whereby the determination of cumulative usage factor (CUF) values for piping components is not required. Piping components may not require analysis for cyclic operation if the piping component meets the requirements of Subparagraph NB-3222.4(d). The criteria to be applied in determining whether a fatigue analysis is required are as follows:

Atmospheric-to-Operating Pressure Cycles

The specified number of times (including startup-shutdown) that the pressure will be cycled from atmospheric pressure to operating pressure and back to atmospheric pressure during normal operation does not exceed the number of cycles on the applicable fatigue curve of Figs. I-9.0 of the Code corresponding to an S_a value of 3 times the S_m value for the material at operating temperature.

Normal Operation Pressure Fluctuations

The specified full range of pressure fluctuations during normal operation does not exceed (1/3) x design pressure x (S_a/ S_m) where S_a is the value obtained from the applicable design fatigue curve for the total specified number of significant pressure fluctuations, and S_m is the allowable stress intensity for the material at operating temperature. If the total specified number of significant pressure fluctuations exceeds 10^6, the S_a value at 10^6 cycles may be used. Significant pressure fluctuations are those for which the total excursion exceeds (1/3) x design pressure x (S/S_m) where S is the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

Startup-Shutdown Temperature Differences

The temperature difference in deg. F between any two adjacent points of the component during normal operation does not exceed $S_a/(2E\alpha)$, where S_a is the value obtained from the applicable design fatigue curves for the specified number of startup-shutdown cycles, α is the value of the instantaneous coefficient of thermal expansion at the mean value of the temperatures at the two points as given by Table I-5.0 of the Code, and E is taken from Table I-6.0 of the Code at the mean value of the temperature at the two points.

Normal Operation Temperature Differences

The temperature difference in deg. F between any two adjacent points does not change during normal operation by more than the quantity $S_a/(2E\alpha)$, where S_a is the value obtained from the applicable design fatigue curve of Fig. I-9.0 of the Code for the total specified number of significant temperature-difference fluctuations. A temperature difference fluctuation shall be considered to be significant if its total algebraic range exceeds the quantity $S/2E\alpha$, where S is the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

Dissimilar Materials Temperature Differences

For components fabricated from materials of differing moduli of elasticity and/or coefficients of thermal expansion, the total algebraic range of temperature fluctuation in deg. F experienced by the component during normal operation does not exceed the magnitude $S_a/2(E_1\alpha_1 - E_2\alpha_2)$, where S_a is the value obtained from the applicable design fatigue curve for the total specified number of significant temperature fluctuations, E_1 and E_2 are the moduli of elasticity, and α_1 and α_2 are the values of the instantaneous coefficients of thermal expansion at the mean temperature value involved for the two materials of construction. (See Tables I-5.0 and I-6.0 of the Code). A temperature fluctuation shall be considered to be significant if its total excursion exceeds the quantity $S/2(E_1\alpha_1 - E_2\alpha_2)$, where S is the value of S_a obtained from the applicable design fatigue curve of Figs. I-9.0 of the Code for 10^6 cycles. If the two materials used have different applicable design fatigue curves, the lower value of S_a shall be used in applying the rules of this paragraph.

Mechanical Loads

The specified full range of mechanical loads, excluding pressure but including pipe reactions, does not result in load stresses whose ranges exceeds the S_a value obtained from the applicable design fatigue curve of Figs. I-9.0 of the Code for the total specified number of significant load fluctuations. If the total specified number of significant load fluctuations exceeds 10^6, the S_a value at 10^6 cycles may be used. A load fluctuation shall be considered to be significant if the total excursion of load stress exceeds the value of S_a obtained from the applicable design fatigue curve for 10^6 cycles.

RAI 4.3.3-2

Background

In LRA (Supplement 1) Section 4.3.1.4, the applicant disposes the TLAA for Class 1, 2 and 3 piping components in accordance with both 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(ii).

Issue

The regulatory disposition statements should be part specific if not all parts of the analysis group consistently fall in the same disposition class.

Request

In the regulatory disposition statement, identify which parts of the piping components are managed in accordance with 10 CFR 54.21(c)(1)(i) and which are managed in accordance with 10 CFR 54.21(c)(1)(ii).

DAEC Response to RAI 4.3.3-2

Section 4.3.1.4 cited in the Background section should reference Section 4.3.3.

In LRA Section 4.3.3 on page 4.3-6, the regulatory disposition statement is revised to read as follows:

Disposition: 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(ii) as shown below:

(i) The analyses remain valid for the period of extended operation:

- Class 1 piping systems designed in accordance with B31.1 methodology
- Fatigue-exempt Class 1 piping systems
- Class 2 and 3 piping systems designed in accordance with B31.1 or B31.7

(ii) The analyses have been projected to the end of the period of extended operation:

- Class 1 piping systems designed in accordance with B31.7

RAI 4.3.4-1

Background

The opening sentence of LRA (Supplement 1) Section 4.3.4 states that Generic Safety Issue GSI-166 was later renumbered as GSI-190.

Issue

It should be noted that GSI-190 was established to address the residual concerns of GSI-78 and GSI-166 regarding the environmental effects of fatigue on pressure boundary components for 60-years of plant operation. Clearly, GSI-190 is not a renumbered document of GSI-166.

Request

Please correct the affected statement of LRA appropriately.

DAEC Response to RAI 4.3.4-1

In LRA Section 4.3.4, Effects of Reactor Coolant Environment (GSI 190), on page 4.3-7, replace the first sentence under Description with the following:

> Generic Safety Issue (GSI) 190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," was identified by the NRC because of concerns about the effects of reactor water environments on the fatigue life of components and piping during the period of extended operation.

RAI 4.3.4-2

Background

LRA (Supplement 1) Section 4.3.4 describes the environmental fatigue evaluation and the results are presented in LRA Table 4.3.4-1, including the Fen values determined for each component or location evaluated.

At some point in LRA (Supplement 1) Section 4.3.4, the applicant states, "Bounding Fen values are determined, or Fen values are computed for each load pair in the detailed fatigue calculation for each component". The applicant also states, "HWC conditions were assumed to exist for 72.4% of the time, and NWC conditions to exist 27.6% of the time".

Issue

It is known that F_{en} depends on material, strain rates, sulphur content, temperature and the dissolved oxygen (DO) concentration of the reactor water. However, this information is not provided in the LRA.

Request

1. Summarize DAEC's experience in control of DO level in the reactor water since the plant startup. Describe all water chemistry programs DAEC has used, including procedures and requirements used for managing DO concentration as well as the inception date of each water chemistry program.
2. Provide a historic summary of the DO level since plant startup. Estimate the fraction of time of the DAEC operating history thus far that the DO level exceeded 0.05 ppm.
3. Describe how reactor water samples were taken, including the sampling locations. If samples were taken from a single location, justify that the DO data discussed in Part (b) are applicable to all NUREG/CR-6260 locations in DAEC for the Fen calculations.
4. Specify the data of dissolved oxygen (DO), strain rate, sulphur content, and temperature used for each load pair in the calculation of Fen.
5. Provide basis that supports the use of the condition that, "72.4% of the time the plant is under HWC chemistry condition and 27.6% of the time the plant is under the NWC chemistry condition".
6. Explain how Fen is evaluated when the component has experienced different levels of DO concentration levels.
7. Provide the reference document that was used for calculating Fen of Nickel alloys.

DAEC Response to RAI 4.3.4-2

Part 1

A historical summary of water chemistry regimes used at DAEC is as follows:

Date	Activity	Duration
Feb. 1974 – July 1987	Pre-HWC (Hydrogen Water Chemistry)	13.5 years
Aug. 1987 – Sept. 1996	Post-HWC/Pre-NMCA (Noble Metals Chemical Addition)(6 scfm)	9.0 years
Oct. 1994 – Apr. 1996	Increased HWC to 9 scfm	1.5 years
Apr. 1996 – Oct. 1996	Temporary Increase HWC Injection Rate To 15 scfm	0.5 years
Oct. 1996 – Present	Post-NMCA (6 scfm)	13.0 years
Present – Feb. 2034	Future (Post-HWC & Post-NMCA)(6 scfm)	29.4 years

From initial plant startup in February 1974 to July 1987, the period prior to hydrogen injection, dissolved oxygen levels in the feedwater were lower than current values, and much higher in the reactor recirculation lines. Samples were obtained then by grab sample, and these values were confirmed by the HWC mini-test data taken in 1987.

Chemistry programs used:

PCP 1.9 - Water Chemistry Guidelines	Inception: 2/25/2000
PCP 1.16 - Chemistry BWRVIP Program	Inception: 5/16/2007
PCP 2.1 - Plant Chemistry Sampling Program Guidelines	Inception: 2/25/2000
PCP 2.13 - Reactor Water Sampling	Inception: 2/25/2000
PCP 2.18 - Reactor Recirc Hydrogen and Oxygen Monitoring	Inception: 2/25/2000
PCP 4.10 - Dissolved Oxygen – Chemet Method	Inception: 4/17/2003
DAEC Strategic Chemistry Plan	Inception: 4/20/2004

Part 2

From February 1974 thru July 1987 was the pre-HWC (Hydrogen Water Chemistry) period (13.5 years). DO was 200 ppb in the reactor.

From August 1987 thru September 1996 was the Post-HWC/Pre-NMCA (Noble Metals Chemical Addition) period during which H2 was added @ 6.0 scfm (9.0 years). DO was 0.2 ppb in the reactor.

From April 1996 thru October 1996, the HWC Injection Rate was temporarily increased to 15 scfm (0.5 years). DO was 0.2 ppb in the reactor.

From October 1996 thru Present was the Post-NMCA (6 scfm) period (13.0 years). DO was 0.2 ppb in the reactor.

Therefore, DAEC has been operating since February 1974 through October 1, 2009 or approximately 35.67 years including refueling outages. The 13.5 years at greater than 0.05 ppm out of 35.67 total years is 37.8% of the time. However, since 1987, HWC system availability has exceeded 95% and DO has been less than 0.05 ppm.

Part 3

Dissolved Oxygen Measurement Locations are as follows:

	Measurement Location	**Frequency of Measurement**	**Achievable Value**
Feedwater line DO2	HP FW htrs outlet (upstream of MO1636 & MO1592) TB Sample Sink – Digital meter	Continuous	30-100 ppb (40 ppb typical)
Rx Recirc line DO2	B Recirc riser hdr (¾" sample line off B Recirc Riser header) 2nd floor Rx Bldg. (AE8912A & AI8912)	Continuous	$\leq$1 ppb (0.2 ppb typical)

Reactor Recirculation line oxygen is typically 0.2 ppb; it should be maintained less than 1 ppb in accordance with EPRI BWR Water Chemistry Guidelines.

The Reactor Recirculation dissolved oxygen measurement is taken from a ¾" line tapped off of the "B" Reactor recirculation riser header. One line supplies the Crack Arrest Verification System (CAVS) where reactor recirculation dissolved oxygen is continuously monitored. Dissolved oxygen analyzer AE-8912A monitors dissolved oxygen in the reactor recirculation water. Both dissolved hydrogen and oxygen concentration are recorded on Panel 1C22 (AR-8900), and output signals are provided to the CAVS computer from local rack 1C703. Recirculation water dissolved oxygen is indicated on Panel 1C22 by AI-8912 (0-10 ppb) or at 1C503 in the plant. Annunciator 1C22 (B-6) RECIRC HI DISSOLVED O_2 will be received at concentrations >5 ppb, increasing. Both analyzers are designed to operate continuously.

The Upper RPV area, RPV Beltline and RPV Bottom Head Region DO levels were calculated using the BWRVIA model. The BWRVIA Radiolysis model is a software tool developed by EPRI to predict ECP and H_2/O_2 molar ratio values for various reactor coolant components. Because DAEC has been treated with Noble Metals, H_2/O_2 molar ratio is the parameter of interest. An H_2/O_2 Molar ratio $\geq$2 demonstrates the plant is mitigated. An H_2/O_2 Molar ratio of $\geq$3 is required by EPRI to provide sufficient margin to demonstrate mitigation. DAEC typically maintains a molar ratio of at least 4. The Recirculation O_2 monitor analyzes the Recirculation piping coolant for dissolved oxygen. The dissolved oxygen meter is then used to validate oxidants are suppressed in the Recirculation piping or calculate the Recirculation piping H_2/O_2 Molar Ratio.

The BWRVIA model uses feedwater hydrogen concentration to perform calculations. The model contains physical plant data and typical plant operational data per PCP 1.16, Chemistry BWRVIP Program. DAEC has version 2 of the model.

Part 4

The equations used to calculate F_{en} are:

For Carbon Steel:

$$F_{en} = \exp(0.585 - 0.00124T' - 0.101S^*T^*O^*\dot{\varepsilon}^*)$$

Substituting T' = 25°C in the above expression to relate room temperature air data to service temperature data in water, the following is obtained:

$$F_{en} = \exp(0.585 - 0.00124(25°C) - 0.101\ S^*\ T^*\ O^*\ \dot{\varepsilon}^*)$$
$$= \exp(0.554 - 0.101\ S^*\ T^*\ O^*\ \dot{\varepsilon}^*)$$

For Low Alloy Steel:

$$F_{en} = \exp(0.929 - 0.00124T' - 0.101S^*T^*O^*\dot{\varepsilon}^*)$$

Substituting T' = 25°C in the above expression to relate room temperature air data to service temperature data in water, the following is obtained:

$$F_{en} = \exp(0.929 - 0.00124(25°C) - 0.101\ S^*\ T^*\ O^*\dot{\varepsilon}^*)$$
$$= \exp(0.898 - 0.101\ S^*\ T^*\ O^*\dot{\varepsilon}^*)$$

Where:

F_{en} = fatigue life correction factor

S^* = S for 0 < sulfur content, S ≤ 0.015 wt. %
= 0.015 for S > 0.015 wt. %

T^* = 0 for T < 150°C
= (T - 150) for 150 ≤ T ≤ 350°C

T = fluid service temperature (°C)

O^* = 0 for dissolved oxygen, DO < 0.05 parts per million (ppm)
= ln(DO/0.04) for 0.05 ppm ≤ DO ≤ 0.5 ppm
= ln(12.5) for DO > 0.5 ppm

$\dot{\varepsilon}^*$ = 0 for strain rate, $\dot{\varepsilon}^* > 1\%/\text{sec}$
= $\ln(\dot{\varepsilon}^*)$ for $0.001 \le \dot{\varepsilon}^* \le 1\%/\text{sec}$
= ln(0.001) for $\dot{\varepsilon}^* < 0.001\%/\text{sec}$

<u>For Types 304 and 316 Stainless Steel:</u>

$F_{en} = \exp(0.935 - T^* \dot{\varepsilon}^* O^*)$

Where:

F_{en} = fatigue life correction factor

T^* = 0 for T < 200°C
= 1 for T ≥ 200°C

T = fluid service temperature (°C)

$\dot{\varepsilon}^*$ = 0 for strain rate, $\dot{\varepsilon} > 0.4\%/\text{sec}$
= $\ln(\dot{\varepsilon}/0.4)$ for $0.0004 \le \dot{\varepsilon} \le 0.4\%/\text{sec}$
= ln(0.0004/0.4) for $\dot{\varepsilon} < 0.0004\%/\text{sec}$

O^* = 0.260 for dissolved oxygen, DO < 0.05 parts per million (ppm)
= 0.172 for DO ≥ 0.05 ppm

As seen in the above equations, the values of F_{en} for carbon steel, low alloy steel and Types 304 and 316 stainless steel are affected by dissolved oxygen (DO) concentration. The value of DO varies with location (reactor vessel, recirculation line, etc) and whether or not HWC is utilized. HWC was implemented at DAEC in 1987. The average availability since implementation exceeds 90%, and projected future availability of the HWC system is greater than 95%.

The following values are used for DO:

Feedwater line DO is 20 ppb for pre-HWC and 60 ppb for post-HWC conditions.

Recirculation line DO is 200 ppb pre-HWC and 0.2 ppb post-HWC.

RPV Upper Region DO is 90 ppb pre-HWC and 66 ppb post-HWC.

RPV Beltline DO is 200 ppb pre-HWC and 0 ppb post-HWC.

RPV Bottom Head Region DO is 134 ppb pre-HWC and 0.3 ppb post-HWC.

RPV Lower Head

The material for the limiting location is low alloy steel.

$F_{en} = \exp(0.898 - 0.101\ S^*\ T^*\ O^*\dot{\varepsilon}^*)$
Assuming S* = 0.015 (maximum) and ε* = ln(0.001) = -6.908 (minimum)

<u>Post-HWC implementation F_{en} is determined as follows</u>:
DO = 0.3 ppb (which is less than 0.050 ppm, so O* = 0,
$F_{en} = \exp(0.898 - 0.101S^*T^*O^*\varepsilon^*)$
$F_{en} = \exp(0.898 - 0.0) = \exp(0.898)$
= 2.45

<u>Pre-HWC implementation F_{en} is determined as follows</u>:
DO = 134 ppb = 0.134 ppm, so O* = ln(0.134/.04) = ln(3.35) = 1.2090
$F_{en} = \exp(0.898 - 0.101S^*T^*O^*\varepsilon^*)=$
$F_{en} = \exp(0.898 - (0.101)(0.015)(T^*)(1.2090)(-6.908))$
$F_{en} = \exp(0.898 + (0.012652)(T^*))$

For T = 0 °C
$F_{en} = \exp(0.898 + (0.012652)(0))$
= 2.45 for T = 0°C

For T = 288 °C (where T*=(T-150)
$F_{en} = \exp(0.898 + (0.012652)(288-150))$
$F_{en} = \exp(0.898 + (0.012652)(138))$
$F_{en} = \exp(0.898 + 1.7461)$
$F_{en} = \exp(2.6441)$
= 14.07 for T = 288°C

As shown in the response to (5), Overall HWC Availability = 0.72425. Therefore,

Overall $F_{en} = 0.72425^*F_{en\ HWC} + (1-0.7245)^*F_{en\ NWC}$
Overall $F_{en} = 0.72425^*2.45 + (1-0.7245)^*14.07$
Overall $F_{en} = 5.66$

Recirculation inlet nozzle safe end

The material for the limiting location is SB-166 (Alloy 600).

As shown in the response to (7), F_{en} = 1.49.

Recirculation Outlet Nozzle:

Load-pair environmentally-assisted fatigue (EAF) calculations were performed for the recirculation outlet nozzle safe end location and nozzle corner location. For the recirculation outlet nozzle safe end location the overall environmental multiplier is 13.42. For the nozzle corner location the overall environmental multiplier is 7.02.

For details of the load-pair calculations, see Table 7 and Table 8, respectively, of calculation DAEC-20Q-304 provided at the end of this RAI response.

Core Spray Nozzle:

For the SB166 (Alloy 600) safe end location, F_{en} = 1.49.

A load-pair EAF calculation was performed for the nozzle corner location using temperature-dependent F_{en} multipliers for each load pair. The overall F_{en} is 5.00.

For details of the load-pair calculation, see Table 8 of calculation DAEC-20Q-320 provided at the end of this RAI response.

Feedwater Nozzle:

For the SB166 safe end location, F_{en} = 1.49.

A load-pair basis EAF calculation for the nozzle corner was performed. The overall environmental multiplier is 3.19.

A load-pair basis EAF calculation for the carbon steel safe end was performed. The overall environmental multiplier is 1.74.

For details of the load-pair calculations, see Table 16 and Table 18, respectively, of calculation DAEC-20Q-307, provided at the end of this RAI response.

B RHR Return Tee

For stainless steel,

$$F_{en} = \exp(0.935 - T^* \dot{\varepsilon}^* O^*)$$

For $\dot{\varepsilon} > 0.4\%/\text{sec}$, $\dot{\varepsilon}^* = 0$

For $0.0004 \le \dot{\varepsilon} \le 0.4\%/\text{sec}$, $\dot{\varepsilon}^* = \ln(\dot{\varepsilon}/0.4)$ = ranges from -6.908 to 0

For $\dot{\varepsilon} < 0.0004\%/\text{sec}$, $\dot{\varepsilon}^* = \ln(0.0004/0.4) = -6.908$

For DO < 0.05 ppm, $O^* = 0.260$
For DO ≥ 0.05 ppm, $O^* = 0.172$

For $T < 200°C$, $T^* = 0$
For $T \geq 200°C$, $T^* = 1$

Post-HWC implementation F_{en} is determined as follows:
DO = 0.2 ppb (= 0.0002 ppm, which is less than 0.050 ppm), so $O^* = 0.260$)
Conservatively use $T^* = 1$ for T>200°C

$F_{en} = \exp(0.935 - T^* \dot{\varepsilon}^* O^*) = \exp(0.935 - (1)(\dot{\varepsilon}^*)(0.260))$

For $\dot{\varepsilon} > 0.4\%/\text{sec}$, $\dot{\varepsilon}^* = 0$, so $F_{en} = \exp(0.935) = 2.55$

For $\dot{\varepsilon} < 0.0004\%/\text{sec}$, $\dot{\varepsilon}^* = -6.908$, so $F_{en} = \exp(0.935 - (0.260)(-6.908)) = 15.35$

Pre-HWC implementation F_{en} is determined as follows:
DO = 200 ppb (= 0.200 ppm, which is greater than 0.050 ppm), so $O^* = 0.172$
Conservatively use $T^* = 1$ for T>200°C

$F_{en} = \exp(0.935 - T^* \dot{\varepsilon}^* O^*) = \exp(0.935 - (1)(\dot{\varepsilon}^*)(0.172))$

for $\dot{\varepsilon} > 0.4\%/\text{sec}$, $\dot{\varepsilon}^* = 0$, so $F_{en} = \exp(0.935) = 2.55$

For $\dot{\varepsilon} < 0.0004\ \%/\text{sec}$, $\dot{\varepsilon}^* = -6.908$, so $F_{en} = \exp(0.935 - (-6.908)(0.172)) = 8.36$

Overall HWC Availability = 0.72425, therefore,
Overall $F_{en} = 0.72425 * F_{en\ HWC} + (1-0.7245) * F_{en\ NWC}$
Overall $F_{en} = 13.42$

Feedwater/RCIC Piping Connection

For carbon steel,

$F_{en} = \exp(0.554 - 0.101\ S^*\ T^*\ O^*\ \dot{\varepsilon}^*)$

Assuming $S^* = 0.015$ (maximum) and $\varepsilon^* = \ln(0.001) = -6.908$ (minimum),
Post-HWC implementation F_{en} is determined as follows:
DO = 60 ppb (= 0.060 ppm, so $O^* = \ln(0.060/0.04) = \ln(1.5) = 0.405$
$F_{en} = \exp(0.554 - (0.101)(0.015)(T^*)(0.405)(-6.908)) = \exp(0.554 + 0.004238T^*)$
for T= 0 C
$F_{en} = \exp(0.554) = 1.74$
For T = 288 C ($T^* = T-150 = 288-150 = 138$ C)
$F_{en} = \exp(0.554 + 0.004238(138)) = 3.13$

Pre-HWC implementation F_{en} is determined as follows:
DO = 20 ppb = 0.020 ppm, (less than 0.050 ppm) so $O^* = 0$
$F_{en} = \exp(0.554 - 0.101\ S^*\ T^*\ O8\ \varepsilon^*)$
$F_{en} = \exp(0.554 - 0) =$
$F_{en} = \exp(0.554)$
$F_{en} = 1.74$

Overall HWC Availability = 0.72425, therefore,
Overall F_{en} = 0.72425*$F_{en\ HWC}$ + (1-0.7245)*$F_{en\ NWC}$
Overall F_{en} = 0.72425*3.13+ (1-0.7245)*1.74
Overall F_{en} = 2.27 + .47
Overall F_{en} = 2.74

RHR-Recirc Piping

For carbon steel:

$F_{en} = \exp(0.554 - 0.101\ S^*\ T^*\ O^*\ \dot{\varepsilon}^*)$

Assuming S* = 0.015 (maximum) and ε* = ln(0.001) = -6.908 (minimum),
<u>Post-HWC implementation F_{en} is determined as follows:</u>
DO = 0.2 ppb (= 0.0002 ppm, which is less than 0.050 ppm, so O* = 0)
F_{en} = exp(0.554 – 0) = exp(0.554) = 1.74

<u>Pre-HWC implementation F_{en} is determined as follows:</u>
DO = 200 ppb = 0.200 ppm, so O* = ln(0.200/0.04) = 1.60944
F_{en} = exp (0.554 - 0.101 S* T* O* ε*)
F_{en} =exp(0.554 - (0.101)(0.015)(T*)(1.60944)(-6.908)) =
F_{en} =exp(0.554 + 0.016844T*) where T*=(T-150) for T >150 C

For T=0 C
F_{en} =exp(0.554)
F_{en} =1.74

For T=288 °C, T*= 288 °C -150 °C = 138 °C
F_{en} =exp(0.554 + 0.016844T*)
F_{en} =exp(0.554 + 0.016844(138)T*)
F_{en} =exp(2.87792)
F_{en} = 17.79

Overall HWC Availability = 0.72425, therefore,
Overall F_{en} = 0.72425*$F_{en\ HWC}$ + (1-0.7245)*$F_{en\ NWC}$
Overall F_{en} = 0.72425*1.74+ (1-0.7245)*17.79 = Overall F_{en} = 1.26 + 4.90
Overall F_{en} = 6.17

<u>Part 5</u>

To perform the environmental fatigue evaluations, HWC conditions were assumed to exist for 72.4% of the time, and normal water chemistry (NWC) conditions to exist for 27.6% of the time, as shown below:

Overall HWC Availability = [(T1 * 0) + (T2 * A1) + (T3 * A2)]/(T1 + T2 + T3), where

A1 = 90% (HWC availability since HWC implementation)
A2 = 95% (HWC availability for future operation)
T1 is time at pre-HWC conditions = 13.35 years

T2 is time since HWC implementation = 17.25 years
T3 is future time for HWC operation = 29.40 years

Overall HWC Availability = ((13.35*0)+(17.25*0.90)+(29.40*0.95))/(13.35+17.25+29.40) = 0.72425.

Part 6

As shown in the response to (4), the calculation of F_{en} included effects of DO concentration.

Part 7

The value for F_{en} of nickel alloys is determined based on the Alloy 600 methodology documented in "Status of Fatigue Issues at Argonne National Laboratory," presented at EPRI Conference on Operating Nuclear Power Plant Fatigue Issues & Resolutions, O. Chopra, Snowbird, UT, August 22-23, 1996. This is supported by Section 3.3 of EPRI Report No. TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Fatigue Evaluations," Palo Alto, CA, December 1995.

The following F_{en} value is determined based on the Alloy 600 methodology:

In air, $T < 150°C$: $\ln(N_{air}) = 6.940 - 1.776 \ln(\varepsilon_a - 0.12)$
In air, $T \geq 150°C$: $\ln(N_{air}) = 7.438 - 1.776 \ln(\varepsilon_a - 0.12)$
In water, $T < 150°C$: $\ln(N_{water}) = 6.539 - 1.776 \ln(\varepsilon_a - 0.12)$
In water, $T \geq 150°C$: $\ln(N_{water}) = 7.037 - 1.776 \ln(\varepsilon_a - 0.12)$

where: ε_a = strain amplitude (%)
N = fatigue life (cycles to form a 3-mm deep crack)
T = temperature (°C)

Note that the expressions for Alloy 600 are only dependent upon strain amplitude and temperature (i.e., they are independent of dissolved oxygen). In addition, the above determination of F_{en} yields a constant value for all temperatures that is also independent of strain amplitude. Thus, a constant F_{en} value of 1.49 is obtained for all operating conditions for Alloy 600 material, regardless of temperature, dissolved oxygen content, and strain amplitude.

For $T < 150°C$:

$$
\begin{aligned}
F_{en} &= N_{air}/N_{water} \\
\ln(F_{en}) &= \ln(N_{air}/N_{water}) \\
&= \ln(N_{air}) - \ln(N_{water}) \\
&= 6.940 - 1.776 \ln(\varepsilon_a - 0.12) - [\,6.539 - 1.776 \ln(\varepsilon_a - 0.12)\,] \\
&= 6.940 - 6.539 \\
&= 0.401
\end{aligned}
$$

So, F_{en} = exp(0.401) = 1.49.

A similar process results in the same value of F_{en} for T ≥ 150°C. Thus, a constant F_{en} value of 1.49 is obtained for all temperatures for Alloy 600 material.

Table 7: EAF Fatigue Usage Calculation for the Safe End Location

DAEC RO Safe End Environmental Fatigue Calculation
CUF Calculation from file VFAT-1i.fat:

Transient Maximum Temperatures:

EAF Calculations:

	HWC DO	NWC DO	
(DO and HWC/NWC Inputs from Table 2 of Reference [7])	0	200	ppb
% HWC =	72.4%	27.6%	= % NWC

From "VFAT-1i.ALL":

Index	Load #1	Description #1	Load #2	Description #2	Line #	T1 (4)	s1 (4)	T2 (4)	s2 (4)	S_a (psi)	T (°F) (1)	T_{MAX} (°F) (1)	T_{MAX} (°C)	HWC F_{en} (2)	NWC F_{en} (2)	U_{env} (3)
1	51	17_ImpSt2	52	17_ImpSt3	458602	51	53	52	6	88,108	515	516.0	268.3	15.348	8.357	0.19566
2	17	11_LOFP2	53	17_ImpSt4	235309	17	6	53	1	26,211	530	530.0	276.7	15.348	8.357	0.00002
3	17	11_LOFP2	45	15_SCRAM2	234134	17	6	45	10	25,954	557	557.0	291.7	15.348	8.357	0.00001
4	19	11_LOFP4	45	15_SCRAM2	264444	19	5	45	10	24,045	557	557.0	291.7	15.348	8.357	0.00002
5	21	11_LOFP6	45	15_SCRAM2	299311	21	3	45	10	21,950	557	557.0	291.7	15.348	8.357	0.00001
6	20	11_LOFP5	45	15_SCRAM2	282701	20	43	45	10	20,382	557	557.0	291.7	15.348	8.357	0.00000

Total, U_{60-env} =	0.19572
Overall F_{en} =	13.42

Notes:
1. T_{MAX} is the maximum temperature of the two paired load states, and represents the metal (nodal) temperature at the location being analyzed. This is determined from the VESLFAT output, which is included as "T" in the "Transient Maximum Temperatures" table above.
2. F_{en} values computed using the stainless steel equation from Section 2.0 of Reference [7], with the transformed strain rate conservatively set to a minimum value of ln (0.0004/0.4) = -6.908 for all load pairs.
3. U_{env} = [U x HWC F_{en} x % HWC] + [U x NWC F_{en} x % NWC].
4. T1 and T2 represent the load number for Load #1 and Load #2, respectively, and s1 and s2 represent the state number for each of those loads.

Table 8: EAF Fatigue Usage Calculation for the Nozzle Corner Location

DAEC RO Nozzle Corner Environmental Fatigue Calculation

Transient Maximum Temperatures:

From "VFAT-2i.ALL":

Index	Load #1	Description #1	Load #2	Description #2	Line #	T1 [4]	s1 [4]	T2 [4]	s2 [4]	S_a (psi)	T (°F) [1]
1	1	2_Dhydro1	16	11_LOFP2	289	1	1	16	8	66,362	369
2	1	2_Dhydro1	43	17_ImpSt2	862	1	1	43	54	52,049	381
3	1	2_Dhydro1	44	17_ImpSt3	864	1	1	44	1	52,189	390
4	1	2_Dhydro1	17	11_LOFP3	291	1	1	17	1	66,079	360
5	1	2_Dhydro1	31	13_OverPres2	576	1	1	31	1	57,663	533
6	1	2_Dhydro1	50	24_Hydro2	987	1	1	50	1	61,905	100
7	1	2_Dhydro1	18	11_LOFP4	335	1	1	18	8	48,737	349
8	1	2_Dhydro1	15	11_LOFP1	281	1	1	15	19	50,493	499
9	1	2_Dhydro1	20	11_LOFP6	387	1	1	20	8	45,134	329
10	20	11_LOFP6	37	14_SRVBdn3	299573	20	8	37	33	43,564	329
11	5	3_Startup2	20	11_LOFP6	22958	5	12	20	8	43,216	329
12	5	3_Startup2	19	11_LOFP5	21366	5	12	19	1	47,233	338
13	5	3_Startup2	25	12_TurbTrip2	27795	5	12	25	1	6,750	533
14	5	3_Startup2	8	4_Turb2	10995	5	12	8	20	43,151	536
15	8	4_Turb2	48	21_ShtDn4	107485	8	20	48	33	43,373	536
16	2	2_Dhydro2	48	21_ShtDn4	1968	2	1	48	33	47,834	100
17	9	4_Turb3	48	21_ShtDn4	113382	9	1	48	33	43,550	535
18	9	4_Turb3	49	24_Hydro1	113581	9	1	49	1	43,550	535
19	9	4_Turb3	51	24_Hydro3	113595	9	1	51	1	43,550	535
20	3	2_Dhydro3	9	4_Turb3	2087	3	1	9	1	43,550	535
21	3	2_Dhydro3	12	9_LOFH3	2154	3	1	12	8	42,917	535
22	3	2_Dhydro3	40	15_SCRAM3	2759	3	1	40	41	42,530	536
23	4	3_Startup1	40	15_SCRAM3	7440	4	1	40	41	42,530	536
24	4	3_Startup1	33	13_OverPres4	6659	4	1	33	22	42,524	536
25	4	3_Startup1	28	12_TurbTrip5	6082	4	1	28	39	6,324	536
26	4	3_Startup1	29	12_TurbTrip6	6278	4	1	29	1	6,358	535
27	4	3_Startup1	34	13_OverPres5	6776	4	1	34	1	42,783	535
28	4	3_Startup1	22	11_LOFP8	5594	4	1	22	43	42,138	535
29	4	3_Startup1	13	9_LOFH4	4028	4	1	13	1	42,744	534
30	4	3_Startup1	7	4_Turb1	3390	4	1	7	17	42,297	551
31	41	15_SCRAM4	47	21_ShtDn3	454812	41	1	47	19	38,231	534
32	7	4_Turb1	47	21_ShtDn3	88707	7	17	47	19	37,929	551
33	7	4_Turb1	21	11_LOFP7	79526	7	17	21	20	35,285	551
34	7	4_Turb1	46	21_ShtDn2	88358	7	17	46	8	37,258	551
35	14	9_LOFH5	46	21_ShtDn2	216346	14	9	46	6	37,469	534
36	23	11_LOFP9	46	21_ShtDn2	355018	23	1	46	6	37,378	533
37	11	9_LOFH2	46	21_ShtDn2	155463	11	29	46	7	37,068	546
38	45	21_ShtDn1	46	21_ShtDn2	465011	45	1	46	7	37,055	557
39	6	3_Startup3	45	21_ShtDn1	71446	6	27	45	35	24,224	557
40	6	3_Startup3	36	14_SRVBdn2	65286	6	27	36	12	29,467	557
41	6	3_Startup3	42	17_ImpSt1	68374	6	1	42	6	18,623	533

EAF Calculations:

(DO and HWC/NWC inputs from Table 2 of Reference [7])	HWC DO	NWC DO	
	0	200	ppb
% HWC =	72.4%	27.6%	= % NWC

T_{MAX} (°F) [1]	T_{MAX} (°C)	HWC F_{en} [2]	NWC F_{en} [2]	U_{env} [3]
369.0	187.2	2.455	4.595	0.00387
381.0	193.9	2.455	5.141	0.00191
390.0	198.9	2.455	5.593	0.00190
360.0	182.2	2.455	4.224	0.00259
533.0	278.3	2.455	21.318	0.00052
100.0	37.8	2.455	2.455	0.00017
349.0	176.1	2.455	3.811	0.00134
499.0	259.4	2.455	16.509	0.00276
329.0	165.0	2.455	3.160	0.00054
329.0	165.0	2.455	3.160	0.00019
329.0	165.0	2.455	3.160	0.00010
338.0	170.0	2.455	3.438	0.00079
533.0	278.3	2.455	21.318	0.00800
536.0	280.0	2.455	21.925	0.04109
536.0	280.0	2.455	21.925	0.00071
100.0	37.8	2.455	2.455	0.00360
535.0	279.4	2.455	21.720	0.03683
535.0	279.4	2.455	21.720	0.00023
535.0	279.4	2.455	21.720	0.00023
535.0	279.4	2.455	21.720	0.00322
535.0	279.4	2.455	21.720	0.00132
536.0	280.0	2.455	21.925	0.00837
536.0	280.0	2.455	21.925	0.01778
536.0	280.0	2.455	21.925	0.00022
536.0	280.0	2.455	21.925	0.00658
535.0	279.4	2.455	21.720	0.00653
535.0	279.4	2.455	21.720	0.00022
535.0	279.4	2.455	21.720	0.00168
534.0	278.9	2.455	21.518	0.00124
551.0	288.3	2.455	25.228	0.01290
534.0	278.9	2.455	21.518	0.01299
551.0	288.3	2.455	25.228	0.01360
551.0	288.3	2.455	25.228	0.00105
551.0	288.3	2.455	25.228	0.00134
534.0	278.9	2.455	21.518	0.00064
533.0	278.3	2.455	21.318	0.00081
546.0	285.6	2.455	24.075	0.00065
557.0	291.7	2.455	26.685	0.02031
557.0	291.7	2.455	26.685	0.00047
557.0	291.7	2.455	26.685	0.00003
533.0	278.3	2.455	21.318	0.00000
			Total, $U_{60\text{-}env}$ =	0.21731
			Overall F_{en} =	7.02

Notes:
1. T_{MAX} is the maximum temperature of the two paired load states, and represents the metal (nodal) temperature at the location being analyzed. This is determined from the VESLFAT output, which is included as "T" in the "Transient Maximum Temperatures" table above.
2. F_{en} values computed using the low alloy steel equation from Section 2.0 of Reference [7], with S* conservatively set to a maximum value of 0.015, and the transformed strain rate conservatively set to a minimum value of ln (0.001) = -6.908 for all load pairs.
3. U_{env} = [U x HWC F_{en} x % HWC] + [U x NWC F_{en} x % NWC].
4. T1 and T2 represent the load number for Load #1 and Load #2, respectively, and s1 and s2 represent the state number for each of those loads.

Table 8: EAF Fatigue Usage Calculation for the Nozzle Corner Location

DAEC CS Nozzle Corner Environmental Fatigue Calculation
CUF Calculation from file VFAT-2i.fat:

Index	Load #1	Description #1	n_1 (cycles) (5)	Load #2	Description #2	n_2 (cycles) (5)	n (cycles) (5)	S_n (psi)	K_e	S_{alt} (psi)	N_{allow}	U
1	12	LFWP4_	8	36	EStdn	10	8	70,662	1.000	47,197	5,256.52	0.00152
2	13	LFWP5_	8	36	EStdn	2	2	71,009	1.000	45,888	5,714.09	0.00035
3	1	DePreT1_	49	13	LFWP5_	6	6	70,879	1.000	45,808	5,743.86	0.00104
4	1	DePreT1_	43	23	OvPre1_	1	1	65,502	1.000	41,213	7,859.76	0.00013
5	1	DePreT1_	42	34	HydTs2_	1	1	70,447	1.000	41,103	7,922.17	0.00013
6	1	DePreT1_	41	24	OvPre2_	1	1	61,715	1.000	38,827	9,381	0.00011
7	1	DePreT1_	40	11	LFWP3_	8	8	56,841	1.000	37,264	10,688	0.00075
8	1	DePreT1_	32	10	LFWP2_	8	8	57,874	1.000	36,412	11,564	0.00069
9	1	DePreT1_	24	14	LFWP6_	8	8	53,173	1.000	35,018	13,208	0.00061
10	1	DePreT1_	16	20	TbTp1_	30	16	55,395	1.000	34,851	13,425	0.00119
11	20	TbTp1_	14	27	SRVB2_	2	2	53,540	1.000	33,690	15,066	0.00013
12	3	DePreT3_	49	20	TbTp1_	12	12	53,142	1.000	33,431	15,466	0.00078
13	3	DePreT3_	37	15	LFWP7_	8	8	50,399	1.000	31,906	18,131	0.00044
14	2	DePreT2_	49	33	HydTs1_	1	1	54,087	1.000	31,557	18,823	0.00005
15	2	DePreT2_	48	3	DePreT3_	29	29	54,087	1.000	31,557	18,823	0.00154
16	2	DePreT2_	19	35	HydTs3_	1	1	54,087	1.000	31,557	18,823	0.00005
17	2	DePreT2_	18	32	Stdn2_	212	18	54,087	1.000	31,557	18,823	0.00096
18	4	Startup	212	5	TBRL1_	176	176	48,699	1.000	31,214	19,537	0.00901
19	25	OvPre3_	1	32	Stdn2_	194	1	48,409	1.000	30,841	20,319	0.00005
20	4	Startup	36	29	OSCRM2_	110	36	48,224	1.000	30,802	20,398	0.00176
21	22	TbTp3_	30	32	Stdn2_	193	30	48,224	1.000	30,802	20,398	0.00147
22	29	OSCRM2_	74	32	Stdn2_	163	74	48,224	1.000	30,802	20,398	0.00363
23	7	LFWH2_	6	32	Stdn2_	89	6	48,216	1.000	30,669	20,670	0.00029
24	19	LFWP11_	8	32	Stdn2_	83	8	48,020	1.000	30,418	21,198	0.00038
25	8	LFWH3_	6	32	Stdn2_	75	6	48,042	1.000	30,397	21,242	0.00028
26	31	Stdn1_	212	32	Stdn2_	69	69	47,692	1.000	30,143	21,798	0.00317
27	30	RDCPW	212	31	Stdn1_	143	143	43,010	1.000	26,432	32,625	0.00438
28	26	SRVB1_	2	30	RDCPW	69	2	29,229	1.000	17,077	176,706	0.00001
											Total, U =	0.03490

Table 8 (Continued): EAF Fatigue Usage Calculation for the Nozzle Corner Location

Transient Maximum Temperatures:

From "VFAT-2LALL":

Index	Load #1	escription	(cycles)	Load #2	escription	Line #	T1 (4)	s1 (4)	T2 (4)	s2 (4)	Sn (psi)	T (°F) (1)
1	12	LFWP4_	8	36	EStdn	218741	12	14	36	142	70,662	310
2	13	LFWP5_	8	36	EStdn	239191	13	1	36	142	71,009	327
3	1	DePreT1_	49	13	LFWP5_	239	1	1	13	1	70,879	327
4	1	DePreT1_	43	23	OvPre1_	512	1	1	23	3	65,502	533
5	1	DePreT1_	42	34	HydTs2_	932	1	1	34	1	70,447	100
6	1	DePreT1_	41	24	OvPre2_	514	1	1	24	1	61,715	533
7	1	DePreT1_	40	11	LFWP3_	217	1	1	11	7	56,841	440
8	1	DePreT1_	32	10	LFWP2_	210	1	1	10	1	57,874	533
9	1	DePreT1_	24	14	LFWP6_	280	1	1	14	13	53,173	307
10	1	DePreT1_	16	20	TbTp1_	434	1	1	20	2	55,395	533
11	20	TbTp1_	14	27	SRVB2_	359757	20	2	27	2	53,540	533
12	3	DePreT3_	49	20	TbTp1_	2573	3	1	20	2	53,142	533
13	3	DePreT3_	37	15	LFWP7_	2428	3	1	15	1	50,399	321
14	2	DePreT2_	49	33	HydTs1_	2001	2	1	33	1	54,087	100
15	2	DePreT2_	48	3	DePreT3_	1076	2	1	3	1	54,087	100
16	2	DePreT2_	19	35	HydTs3_	2003	2	1	35	1	54,087	100
17	2	DePreT2_	18	32	Stdn2_	2000	2	1	32	40	54,087	100
18	4	Startup	212	5	TBRL1_	3251	4	1	5	37	48,699	533
19	25	OvPre3_	1	32	Stdn2_	461015	25	43	32	30	48,409	533
20	4	Startup	36	29	OSCRM2_	38926	4	1	29	40	48,224	533
21	22	TbTp3_	30	32	Stdn2_	396453	22	40	32	40	48,224	533
22	29	OSCRM2_	74	32	Stdn2_	508173	29	40	32	40	48,224	533
23	7	LFWH2_	6	32	Stdn2_	147500	7	20	32	40	48,216	533
24	19	LFWP11_	8	32	Stdn2_	345681	19	79	32	40	48,020	533
25	8	LFWH3_	6	32	Stdn2_	187061	8	38	32	40	48,042	533
26	31	Stdn1_	212	32	Stdn2_	529696	31	1	32	40	47,692	557
27	30	RDCPW	212	31	Stdn1_	517180	30	58	31	31	43,010	557
28	26	SRVB1_	2	30	RDCPW	476940	26	25	30	61	29,229	557

EAF Calculations: HWC DO NWC DO
(per Reference [7, Table 2]) 66 90 ppb
% HWC = 72% 28% = % NWC

T_{MAX} (°F) (1)	T_{MAX} (°C)	HWC F_{en} (2)	NWC F_{en} (2)	U_{env} (3)
310.0	154.4	2.513	2.549	0.00384
327.0	163.9	2.640	2.762	0.00094
327.0	163.9	2.640	2.762	0.00279
533.0	278.3	4.809	7.294	0.00070
100.0	37.8	2.455	2.455	0.00031
533.0	278.3	4.809	7.294	0.00059
440.0	226.7	3.669	4.705	0.00296
533.0	278.3	4.809	7.294	0.00380
307.0	152.8	2.491	2.513	0.00151
533.0	278.3	4.809	7.294	0.00655
533.0	278.3	4.809	7.294	0.00073
533.0	278.3	4.809	7.294	0.00426
321.0	160.6	2.594	2.685	0.00116
100.0	37.8	2.455	2.455	0.00013
100.0	37.8	2.455	2.455	0.00378
100.0	37.8	2.455	2.455	0.00013
100.0	37.8	2.455	2.455	0.00235
533.0	278.3	4.809	7.294	0.04950
533.0	278.3	4.809	7.294	0.00027
533.0	278.3	4.809	7.294	0.00970
533.0	278.3	4.809	7.294	0.00808
533.0	278.3	4.809	7.294	0.01994
533.0	278.3	4.809	7.294	0.00160
533.0	278.3	4.809	7.294	0.00207
533.0	278.3	4.809	7.294	0.00155
557.0	291.7	5.157	8.168	0.01896
557.0	291.7	5.157	8.168	0.02625
557.0	291.7	5.157	8.168	0.00007
			Total, U =	0.17451
			Overall F_{en} =	5.00

Notes:
1. TMAX is the maximum temperature of the two paired load states, and represents the metal (nodal) temperature at the location being analyzed. This is determined from the VESLFAT output, which is included as "T" in the "Transient Maximum Temperatures" table above.
2. Fen values computed using the low alloy steel equation from Section 2.0 of Reference [7], with S* conservatively set to a maximum value of 0.015, and the transformed strain rate conservatively set to a minimum value of ln (0.001) = -6.908 for all load pairs.
3. Uenv = [U x HWC Fen x % HWC] + [U x NWC Fen x % NWC].
4. T1 and T2 represent the load number for Load #1 and Load #2, respectively, and s1 and s2 represent the state number for each of those loads.
5. For each load pair, n1 is the number of available cycles for Load #1, n2 is the number of available cycles for Load #2, and n is the available number of cycles for the load pair (i.e., the minimum of n1 and n2).

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Table 16: EAF Fatigue Usage Calculation for the Nozzle Corner

CUF Calculation from file br.fat:

Index	Load #1	Description #1	n_1 (cycles) [5]	Load #2	Description #2	n_2 (cycles) [5]	n (cycles) [5]	S_n (psi)	K_e	S_{alt} (psi)	N_{allow}	U
1	2	HYD-2	49	24	LOFP-2	8	8	77908	1.000	51,913	3,895.60	0.0020536
2	2	HYD-2	41	26	LOFP-4	8	8	68040	1.000	50,763	4,183.73	0.0019122
3	2	HYD-2	33	28	LOFP-6	8	8	63795	1.000	48,782	4,749.27	0.0016845
4	2	HYD-2	25	9	TR-2	176	25	75333	1.000	48,512	4,833.82	0.0051719
5	1	HYD-1	49	9	TR-2	151	49	74161	1.000	47,430	5,180.37	0.0094588
6	9	TR-2	102	53	UB-2	49	49	74161	1.000	47,430	5,180	0.0094588
7	5	SU-1	212	9	TR-2	53	53	71628	1.000	45,841	5,731	0.0092472
8	5	SU-1	159	18	TT-2	6	6	71636	1.000	45,834	5,734	0.0010464
9	5	SU-1	153	38	RO-4	1	1	71045	1.000	45,503	5,859	0.0001707
10	5	SU-1	152	41	oSCRAM-2	110	110	71034	1.000	45,502	5,859	0.0187734
11	5	SU-1	42	33	TGT-2	30	30	71026	1.000	45,498	5,861	0.0051188
12	5	SU-1	12	30	LOFP-8	8	8	71024	1.000	45,498	5,861	0.0013650
13	5	SU-1	4	36	RO-2	1	1	66539	1.000	42,901	6,977	0.0001433
14	5	SU-1	3	44	Red-2	212	3	61427	1.000	39,682	8,794	0.0003411
15	44	Red-2	209	48	SD-2	212	209	61427	1.000	39,682	8,794	0.0237667
16	48	SD-2	3	57	20A-2	2298	3	56141	1.000	38,445	9,660	0.0003106
17	49	HT24-1	1	57	20A-2	2293	1	56141	1.000	38,445	9,660	0.0001035
18	51	HT24-3	1	57	20A-2	2292	1	56141	1.000	38,445	9,660	0.0001035
19	55	SRV-2	2	57	20A-2	2291	2	56141	1.000	38,445	9,660	0.0002070
20	29	LOFP-7	8	50	HT24-2	1	1	48214	1.000	30,584	20,846	0.0000480
21	29	LOFP-7	7	57	20A-2	2289	7	40716	1.000	29,600	23,049	0.0003037
											Total, U =	0.0907887

EAF Calculations: (per Reference [7, Table 2])

	HWC DO	NWC DO	
(per Reference [7, Table 2])	66	90	ppb
% HWC =	72.4%	27.6%	= % NWC

T_{MAX} (°F) [1]	T_{MAX} (°C)	HWC F_{en} [2]	NWC F_{en} [2]	U_{env} [3]
360.0	182.2	2.906	3.227	0.00615
391.0	199.4	3.181	3.735	0.00637
398.0	203.3	3.246	3.860	0.00575
354.0	178.9	2.856	3.137	0.01517
354.0	178.9	2.856	3.137	0.02775
354.0	178.9	2.856	3.137	0.02775
354.0	178.9	2.856	3.137	0.02713
354.0	178.9	2.856	3.137	0.00307
358.0	181.1	2.889	3.196	0.00051
358.0	181.1	2.889	3.196	0.05583
358.0	181.1	2.889	3.196	0.01522
358.0	181.1	2.889	3.196	0.00406
499.0	259.4	4.356	6.214	0.00070
428.0	220.0	3.543	4.446	0.00129
428.0	220.0	3.543	4.446	0.09012
317.0	158.3	2.564	2.635	0.00080
317.0	158.3	2.564	2.635	0.00027
317.0	158.3	2.564	2.635	0.00027
317.0	158.3	2.564	2.635	0.00053
410.0	210.0	3.362	4.084	0.00017
410.0	210.0	3.362	4.084	0.00108
			Total, U =	0.29000
			Overall F_{en} =	3.19

Transient Maximum Temperatures:

From "br.ALL":

Index	Load #1	Description #1	n_1 (cycles) [5]	Load #2	Description #2	Line #	T1 [4]	s1 [4]	T2 [4]	s2 [4]	S_n (psi)	T (°F) [1]
1	2	HYD-2	49	24	LOFP-2	1451	2	5	24	5	77,908	360.0000000
2	2	HYD-2	41	26	LOFP-4	1543	2	5	26	1	68,040	391.0000000
3	2	HYD-2	33	28	LOFP-6	1721	2	5	28	3	63,795	398.0000000
4	2	HYD-2	25	9	TR-2	677	2	5	9	11	75,333	354.0000000
5	1	HYD-1	49	9	TR-2	37	1	1	9	11	74,161	354.0000000
6	9	TR-2	102	53	UB-2	16500	9	11	53	1	74,161	354.0000000
7	5	SU-1	212	9	TR-2	4937	5	1	9	11	71,628	354.0000000
8	5	SU-1	159	18	TT-2	4995	5	1	18	6	71,636	354.0000000
9	5	SU-1	153	38	RO-4	5154	5	1	38	14	71,045	358.0000000
10	5	SU-1	152	41	oSCRAM-2	5191	5	1	41	8	71,034	358.0000000
11	5	SU-1	42	33	TGT-2	5121	5	1	33	14	71,026	358.0000000
12	5	SU-1	12	30	LOFP-8	5101	5	1	30	12	71,024	358.0000000
13	5	SU-1	4	36	RO-2	5131	5	1	36	4	66,539	499.0000000
14	5	SU-1	3	44	Red-2	5202	5	1	44	2	61,427	428.0000000
15	44	Red-2	209	48	SD-2	89056	44	2	48	6	61,427	428.0000000
16	48	SD-2	3	57	20A-2	90428	48	6	57	13	56,141	317.0000000
17	49	HT24-1	1	57	20A-2	90789	49	1	57	13	56,141	317.0000000
18	51	HT24-3	1	57	20A-2	91078	51	1	57	13	56,141	317.0000000
19	55	SRV-2	2	57	20A-2	96579	55	6	57	13	56,141	317.0000000
20	29	LOFP-7	8	50	HT24-2	63758	29	11	50	1	48,214	410.0000000
21	29	LOFP-7	7	57	20A-2	65283	29	11	57	14	40,716	410.0000000

Notes:
1. T_{MAX} is the maximum temperature of the two paired load states, and represents the metal (nodal) temperature at the location being analyzed. This is determined from the VESLFAT output, which is included as "T" in the"Transient Maximum Temperatures" table above.
2. F_{en} values computed using the low alloy steel equation from Section 2.0 of Reference [7], with S* conservatively set to a maximum value of 0.015, and the transformed strain rate conservatively set to a minimum value of ln (0.001) = -6.908 for all load pairs.
3. U_{env} = [U x HWC F_{en} x % HWC] + [U x NWC F_{en} x % NWC].
4. T1 and T2 represent the load number for Load #1 and Load #2, respectively, and s1 and s2 represent the state number for each of those loads.
5. For each load pair, n_1 is the number of available cycles for Load #1, n_2 is the number of available cycles for Load #2, and n is the available number of cycles for the load pair (i.e., the *minimum* of n_1 and n_2).

Table 18: EAF Fatigue Usage Calculation for the Carbon Steel Safe End

CUF Calculation from file csse.fat:

Index	Load #1	Description #1	n_1 (cycles) [5]	Load #2	Description #2	n_2 (cycles) [5]	n (cycles) [5]	S_n (psi)	K_e	S_{alt} (psi)	N_{allow}	U
1	36	LOFP-7	8	49	RO-3	1	1	72692	1.220	63,274	2,074.01	0.0004822
2	36	LOFP-7	7	53	oSCRAM-3	110	7	72650	1.217	63,203	2,081.45	0.0033630
3	34	LOFP-5	8	53	oSCRAM-3	103	8	72595	1.215	63,075	2,094.95	0.0038187
4	7	TR-2	176	53	oSCRAM-3	95	95	67578	1.071	51,120	4,091.20	0.0232206
5	7	TR-2	81	45	TGT-3	30	30	67401	1.066	50,828	4,166.51	0.0072003
6	7	TR-2	51	8	TR-3	176	51	66195	1.029	48,405	4,867.90	0.0104768
7	8	TR-3	125	40	LOFP-11	8	8	53812	1.000	38,644	9,513.66	0.0008409
8	8	TR-3	117	73	20A-2	2298	117	48669	1.000	36,971	10,980	0.0106562
9	41	LOFP-12	8	73	20A-2	2179	8	47164	1.000	35,246	12,920	0.0006192
10	73	20A-2	2171	74	20A-3	2296	2171	46514	1.000	34,206	14,307	0.1517491
11	32	LOFP-3	8	74	20A-3	125	8	25062	1.000	29,441	23,432	0.0003414
12	74	20A-3	117	77	20B-2	2376	117	40047	1.000	29,188	24,061	0.0048627
13	77	20B-2	2259	78	20B-3	2376	2259	37635	1.000	27,451	29,048	0.0777650
14	78	20B-3	117	81	20C-2	2544	117	30326	1.000	21,857	64,381	0.0018173
15	31	LOFP-2	8	81	20C-2	2427	8	24688	1.000	21,124	76,243	0.0001049
16	33	LOFP-4	8	81	20C-2	2419	8	26817	1.000	20,385	91,425	0.0000875
17	35	LOFP-6	8	81	20C-2	2411	8	26680	1.000	20,226	94,580	0.0000848
18	59	HSBHU-2	212	81	20C-2	2403	212	26821	1.000	19,940	101,085	0.0020972
19	81	20C-2	2191	82	20C-3	2544	2191	27551	1.000	19,925	101,363	0.0216154
20	44	TGT-2	30	82	20C-3	353	30	19093	1.000	12,797	809,206	0.0000371
21	52	oSCRAM-2	110	82	20C-3	323	110	19072	1.000	12,781	818,606	0.0001344
22	48	RO-2	1	82	20C-3	213	1	19050	1.000	12,784	828,361	0.0000012
23	70	SRV-2	2	82	20C-3	212	2	18463	1.000	12,455	infinite	0.0000000
											Total, U =	0.3213756

EAF Calculations:

(per Reference [7, Table 7])	HWC DO	NWC DO	
	60	20	ppb
% HWC =	72.4%	27.6%	= % NWC

T_{MAX} (°F) [1]	T_{MAX} (°C)	HWC F_{en} [2]	NWC F_{en} [2]	U_{env} [3]
221.0	105.0	1.740	1.740	0.00084
219.0	103.9	1.740	1.740	0.00585
219.0	103.9	1.740	1.740	0.00665
231.0	110.6	1.740	1.740	0.04041
231.0	110.6	1.740	1.740	0.01253
231.0	110.6	1.740	1.740	0.01823
208.0	97.8	1.740	1.740	0.00146
216.0	102.2	1.740	1.740	0.01854
216.0	102.2	1.740	1.740	0.00108
283.0	139.4	1.740	1.740	0.26407
305.0	151.7	1.753	1.740	0.00060
283.0	139.4	1.740	1.740	0.00846
250.0	121.1	1.740	1.740	0.13533
248.0	120.0	1.740	1.740	0.00316
468.0	242.2	2.574	1.740	0.00025
468.0	242.2	2.574	1.740	0.00021
476.0	246.7	2.623	1.740	0.00020
359.0	181.7	1.990	1.740	0.00403
210.0	98.9	1.740	1.740	0.03762
283.0	139.4	1.740	1.740	0.00006
283.0	139.4	1.740	1.740	0.00023
283.0	139.4	1.740	1.740	0.00000
283.0	139.4	1.740	1.740	0.00000
			Total, U =	0.55981
			Overall F_{en} =	1.74

Transient Maximum Temperatures:

From "csse.ALL":

Index	Load #1	Description #1	n_1 (cycles) [5]	Load #2	Description #2	Line #	T1 [4]	s1 [4]	T2 [4]	s2 [4]	S_n (psi)	T (°F) [1]
1	36	LOFP-7	8	49	RO-3	85628	36	4	49	10	72,692	221.0000000
2	36	LOFP-7	7	53	oSCRAM-3	85774	36	4	53	8	72,650	219.0000000
3	34	LOFP-5	8	53	oSCRAM-3	82012	34	3	53	8	72,595	219.0000000
4	7	TR-2	176	53	oSCRAM-3	5171	7	6	53	8	67,578	231.0000000
5	7	TR-2	81	45	TGT-3	4877	7	6	45	6	67,401	231.0000000
6	7	TR-2	51	8	TR-3	3207	7	6	8	4	66,195	231.0000000
7	8	TR-3	125	40	LOFP-11	8469	8	3	40	3	53,812	208.0000000
8	8	TR-3	117	73	20A-2	10343	8	3	73	3	48,669	216.0000000
9	41	LOFP-12	8	73	20A-2	96827	41	2	73	3	47,164	216.0000000
10	73	20A-2	2171	74	20A-3	131421	73	3	74	11	46,514	283.0000000
11	32	LOFP-3	8	74	20A-3	78871	32	3	74	10	25,062	305.0000000
12	74	20A-3	117	77	20B-2	131887	74	11	77	4	40,047	283.0000000
13	77	20B-2	2259	78	20B-3	132657	77	4	78	5	37,635	250.0000000
14	78	20B-3	117	81	20C-2	132859	78	4	81	4	30,326	248.0000000
15	31	LOFP-2	8	81	20C-2	77255	31	5	81	4	24,688	468.0000000
16	33	LOFP-4	8	81	20C-2	81369	33	2	81	4	26,817	468.0000000
17	35	LOFP-6	8	81	20C-2	85036	35	2	81	4	26,680	476.0000000
18	59	HSBHU-2	212	81	20C-2	116375	59	3	81	4	28,921	359.0000000
19	81	20C-2	2191	82	20C-3	133104	81	4	82	2	27,551	210.0000000
20	44	TGT-2	30	82	20C-3	100411	44	6	82	1	19,093	283.0000000
21	52	oSCRAM-2	110	82	20C-3	110817	52	7	82	1	19,072	283.0000000
22	48	RO-2	1	82	20C-3	105439	48	6	82	1	19,050	283.0000000
23	70	SRV-2	2	82	20C-3	130663	70	5	82	1	18,463	283.0000000

Notes:
1. T_{MAX} is the maximum temperature of the two paired load states, and represents the metal (nodal) temperature at the location being analyzed. This is determined from the VESLFAT output, which is included as "T" in the "Transient Maximum Temperatures" table above.
2. F_{en} values computed using the low alloy steel equation from Section 2.0 of Reference [7], with S* conservatively set to a maximum value of 0.015, and the transformed strain rate conservatively set to a minimum value of ln (0.001) = -6.908 for all load pairs.
3. U_{env} = [U x HWC F_{en} x % HWC] + [U x NWC F_{en} x % NWC].
4. T1 and T2 represent the load number for Load #1 and Load #2, respectively, and s1 and s2 represent the state number for each of those loads.
5. For each load pair, n_1 is the number of available cycles for Load #1, n_2 is the number of available cycles for Load #2, and n is the available number of cycles for the load pair (i.e., the minimum of n_1 and n_2).

RAI B.3.2-1

Background

The Acceptance Criteria section of the Aboveground Steel Tank Program in NUREG-1801, Rev. 1, Section XI.M29 recommends that any degradation of steel tank paint, coating, sealant, and chalking will require further evaluation. The degradation of aboveground steel tank is detected by (1) periodic system walkdowns to monitor the degradation of the protective coating and sealant at the metal-concrete interface and (2) thickness measurement of the tank bottom to assess the underground surface conditions in contact with soil or concrete.

Issue

In the DAEC LRA, Appendix B, Section B.3.2 indicates that the applicant's Aboveground Steel Tanks Program is consistent with the NUREG-1801, Rev. 1 Section XI.M29 and does not take any exceptions. It was indicated in the applicant's basis document LRAP-M029 Revision 2, Aboveground Steel Tanks, that the protective coating is visually inspected. Material degradation may also occur in inaccessible locations, such as the tank bottom. These areas are monitored by ultrasonic thickness measurements from inside the tank. It is not clear the techniques used or the monitoring frequency will adequately manage the aging effects of the tank bottoms to ensure their intended function will be maintained during the extended period of operation. In the DAEC operating experience, pitting corrosion was reported for both Condensation Storage Tank IT-5A, and IT-5B during an inspection in 1992. The maximum pit depths were 0.080" and 0.066" for IT-5A and IT-5B, respectively. It is not clear what the acceptance criteria are.

Request

The applicant is requested to:

1. Clarify how visual inspection is adequate to exclude corrosion of aboveground steel tank wall surfaces if no additional thickness measurements are made.
2. Clarify and justify how the frequency of tank bottom thickness measurement to be performed under the preventive maintenance program is sufficient to detect and monitor the effects of corrosion on the tank bottom surfaces.
3. Clarify and justify how the acceptance criteria are determined.

DAEC Response to RAI B.3.2-1

Part 1

NUREG-1801 XI.M29 element Detection of Aging Effects states, "Degradation of exterior carbon steel surfaces cannot occur without degradation of paint or coatings on the outer surface and of sealant and caulking at the interface between the component and concrete. Periodic system walkdowns to confirm that the paint, coating, sealant, and caulking are intact is an effective method to manage the effects of corrosion on the external surface of the component."

As discussed in the DAEC program basis document for the Aboveground Steel Tanks Program, DAEC concurs with this position. The protective coating applied to the exterior surfaces of the Condensate Storage Tanks will inhibit environmental factors from causing corrosion and subsequent loss of material of the tank shell. Therefore, DAEC will use visual inspections of the tank coating to determine the presence of aging effects. The exterior surfaces of the Condensate Storage Tanks walls are fully accessible for these inspections. Maintaining the coatings of the exterior surfaces precludes the need for additional thickness measurements of the tank walls.

This DAEC program attribute is consistent with NUREG-1801.

Part 2

NUREG-1801 XI.M29 element "Detection of Aging Effects" states that "thickness measurement of the tank bottom is to be taken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation."

DAEC has periodically performed UT measurements on the in-scope tank bottoms. Thickness measurements of the tank bottoms were performed in 1995, 1998, 2001 and 2009. The conclusion from the measurements is that no significant degradation or corrosion has occurred. The tank bottom average measured thickness was at or above the specified design nominal thickness of 0.3125 inches, and the tanks have a corrosion allowance of .0625 inches. It has been concluded that the frequency of the periodic inspection is acceptable based on plant specific operating experience.

This DAEC program attribute is consistent with NUREG-1801.

Part 3

NUREG-1801 XI.M29, element "Acceptance Criteria," states, "Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance." DAEC concurs with the GALL that the thickness measurement should be evaluated against the design thickness and corrosion allowance.

The DAEC program basis document for the Aboveground Steel Tanks Program states that thickness measurements from ultrasonic testing are reported to the Protective Coatings Program Owner, who evaluates the results against the tank bottom's design thickness and the corresponding corrosion allowance to determine acceptability. Tank bottom measurements to date indicate that the tank bottom average measured thickness were at or above the specified design nominal thickness of 0.3125 inches. The tanks have a corrosion allowance of .0625 inches.

Inspection of areas of the tank interior surfaces have documented a few areas with localized coating blistering and cracking that led to minor pitting corrosion cells. All areas with identified coating defects were repaired.

This DAEC program attribute is consistent with NUREG-1801.

RAI B.3.3-1

Background

In the DAEC LRA Section B.3.3, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program," the applicant stated that the AMP is "consistent with the ten elements of NUREG-1801, Section XI.M1."

NUREG-1801 Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" recommends the use of ASME Section XI Table IWB-2500-1 to determine the examination of category B-F and B-J welds. DAEC is currently using examination category R-A in accordance with risk-informed methodology approved by the NRC under 10 CFR Part 50, for use during the current ten-year interval for examination of Table IWB-2500-1 category B-F and B-J welds.

Issue

The approval of the risk-informed methodology can not be assumed for the subsequent intervals.

Request

Clarify how the inspection of Categories B-F and B-J will be implemented during the extended period of operation.

DAEC Response to RAI B.3.3-1

During the period of extended operation, the inspection of Categories B-F and B-J welds will be performed in accordance with 10 CFR 50.55a and ASME Code requirements, unless approval has been received from the NRC for relief or use of alternatives.

RAI B.3.3.2

Background

In the DAEC LRA Section B.3.3, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program," the applicant stated that the AMP is "consistent with the ten elements of NUREG-1801, Section XI.M1."

Operating experience and AMP audit discussion with the applicant indicated that DAEC had experienced significant aging effect of stress corrosion cracking (SCC) in its Code Class 1 piping including small bore piping. NUREG-1801, Section XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping," states that "Should evidence of significant aging be revealed by a one-time inspection or previous operating experience, periodic inspection will be proposed, as managed by a plant-specific AMP."

Issue

No specific program was provided to manage the aging effects in small bore piping.

Request

Please provide a plant-specific AMP to address the aging effects of SCC and fatigue in Code Class 1 small bore piping including socket welds.

DAEC Response to RAI B.3.3-2

A plant-specific ASME Code Class 1 Small-bore Piping Inspection Program is provided as new LRA Section, B.3.40, to read as follows:

B.3.40 ASME CODE CLASS 1 SMALL-BORE PIPING INSPECTION

B.3.40.1 PROGRAM DESCRIPTION

Since DAEC has previous operating experience related to degradation in small bore piping, this is a plant specific aging management program. DAEC inspects small bore butt welds less than NPS 4 inch as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program. Five out of a total population of fifty-six ASME Code Class 1 Small Bore butt welds less than 4 inch NPS will receive a volumetric examination prior to the period of extended operation. During each inspection interval during the period of extended operation, a minimum of ten percent of the ASME Code Class 1 Small Bore butt welds less than 4 inch NPS will receive a volumetric examination.

ASME Code Class 1 Small Bore socket welds presently receive a VT-2 visual inspection during system leakage tests each refueling outage per the requirements of IWB-2500-1, Examination Category B-P. DAEC will continue to perform these inspections per the ASME Section XI requirements during the period of extended operation. In addition, if an acceptable nuclear industry methodology for performing volumetric examinations of socket weld fittings is developed, DAEC will perform volumetric examination of a minimum of ten percent of the ASME Code Class 1 small bore socket welds each inspection interval. If the acceptable methodology is developed in the middle of an inspection interval, the number of socket welds to be inspected will be prorated. If volumetric examination of small bore class 1 socket welds becomes a requirement of ASME Section XI, DAEC will perform examinations per the applicable code requirement.

B.3.40.2 NUREG-1801 CONSISTENCY

This is a plant specific program.

B.3.40.3 EXCEPTIONS TO NUREG-1801

This is a plant specific program.

B.3.40.4 ENHANCEMENTS TO DUANE ARNOLD PROGRAM

This is a plant specific program.

B.3.40.5 SCOPE OF PROGRAM

Since DAEC has previous operating experience related to degradation in small bore piping, this is a plant specific aging management program. DAEC inspects small bore butt welds less than NPS 4 inch as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program. Five out of a total population of fifty-six ASME Code Class 1 Small Bore butt welds less than 4 inch NPS will receive a volumetric examination prior to the period of extended operation. During each inspection interval during the period of extended operation a minimum of ten percent of the ASME Code Class 1 Small Bore butt welds less than 4 inch NPS will receive a volumetric examination.

All ASME Code Class 1 small bore socket welds presently receive a VT-2 visual inspection during system leakage tests each refueling outage per the requirements of IWB-2500-1, Examination Category B-P. DAEC will continue to perform these inspections per the ASME Section XI requirements during the period of extended operation. In addition, if a nuclear industry acceptable methodology for performing volumetric examinations of socket weld fittings is developed, DAEC will perform volumetric examination of a minimum of ten percent of the ASME Code Class 1 small bore socket welds each inspection interval.

B.3.40.6 PREVENTIVE ACTIONS

This program is an inspection activity independent of methods to mitigate or prevent degradation.

B.3.40.7 PARAMETERS MONITORED OR INSPECTED

The DAEC ASME Code Class 1 Small-Bore Inspection Program uses volumetric examinations to detect cracking in ASME Code Class 1 small-bore piping butt welds. The program uses VT-2 visual examinations during pressure tests to detect cracks in small bore socket welds.

B.3.40.8 DETECTION OF AGING EFFECTS

Five out of a total population of fifty-six of the ASME Code Class 1 Small Bore butt welds less that 4 inch NPS will receive a volumetric examination prior to the period of extended operation. During each inspection interval during the period of extended operation a minimum of ten percent of the ASME Code Class 1 Small Bore butt welds less that 4 inch NPS will receive a volumetric examination.

All ASME Code Class 1 Small Bore socket welds presently receive a VT-2 visual inspection during system leakage tests each refueling outage per the requirements of IWB-2500-1, Examination Category B-P. DAEC will continue to perform these inspections per the ASME Section XI requirements during the period of extended operation. In addition, if a nuclear industry acceptable methodology for performing volumetric examinations of socket weld fittings is developed, DAEC will perform volumetric examination of a minimum of ten percent of the ASME Code Class 1 small bore socket welds each inspection interval.

B.3.40.9 MONITORING AND TRENDING

The inspection is performed at a sufficient number of locations to assure an adequate sample. The number and sample size will be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations.

Since the inspections are performed as part of the ASME Section XI Program, monitoring and trending is performed to meet code requirements.

B.3.40.10 ACCEPTANCE CRITERIA

If flaws or indications exceed the acceptance criteria of ASME Code, Section XI, Paragraph IWB-3400, they will be evaluated in accordance with ASME Code, Section XI, Paragraph IWB-3131, and additional examinations are performed in accordance with ASME Code, Section XI, Paragraph, IWB-2430.

B.3.40.11 CORRECTIVE ACTIONS

The FPL Quality Assurance Program as described in FPL-1 Quality Assurance Topical Report will be utilized to meet Element 7, Corrective Actions. As discussed in the appendix to NUREG-1801, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

B.3.40.12 CONFIRMATION PROCESS

The FPL Quality Assurance Program as described in FPL-1 Quality Assurance Topical Report will be utilized to meet Element 8 Confirmation Process. As discussed in the appendix to NUREG-1801, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

B.3.40.13 ADMINISTRATIVE CONTROLS

The FPL Quality Assurance Program as described in FPL-1 Quality Assurance Topical Report will be utilized to meet Element 9 Administrative Controls. As discussed in the appendix to NUREG-1801, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

B.3.40.14 OPERATING EXPERIENCE

<u>Recirculation Pump Suction 2-inch diameter Drain Line</u>

Corrective Maintenance Action Request, MAR # 092226 was written to repair a pin hole leak in the 2-inch diameter "B" Recirculation Pump Suction Drain Line. The leak was determined to be from weld number 12 (pipe to elbow) on the 2-inch diameter recirculation drain line. The apparent cause was fatigue failure with the exact cause to be determined by testing of the removed section of piping. In conclusion, it appears that by evidence drawn by the metallurgical test and stress analysis that the fatigue crack was an isolated cracking phenomena in which other forces, i.e., improper fit up at construction together with the natural vibration frequency of the pump, could have induced the stress in the weld to contribute to the fatigue cracking. Since the replacement of the Recirculation Pump Suction Drain Line in 1989, no further cracking of Small Bore Class 1 pipe has been observed.

CRD withdrawal and insertion lines leak discovered on November 20. 1988.

Deviation Report 88-282 describes the failure of CRD withdrawal and insertion lines. The root cause was determined to be TGSCC due to the lines being contaminated with chlorides leached from insulation material in the vicinity with high free chloride content. The leaking CRD piping was repaired and the other piping in the bundle was inspected.

CRD withdrawal and insertion lines leak discovered on May 19, 1990

NG-90-2135, Engineering Evaluation of Potentially Degraded CRD Piping, states that on 5/19/90, leaks were detected from the SW quadrant Control Rod Drive (CRD) insert and withdraw lines. The cracking resulted in all lines in the SW quadrant being replaced. The striations seen during the metallurgical analysis are indicative of high cycle fatigue.

Although the Control Rod Drive insert and withdraw lines discussed above are not ASME Code Class 1 piping, they are small bore stainless steel lines with a reactor coolant environment. Therefore, DAEC feels that this plant specific operating experience would be applicable to ASME Code Class 1 Small Bore Piping.

B.3.40.15 CONCLUSION

The DAEC ASME Code Class 1 Small-Bore Piping Inspection Program provides reasonable assurance that the components managed by this program will continue to meet their current licensing basis requirements during the period of extended operation.

To reflect the addition of this new program into the LRA, additional LRA changes are required, as follows:

LRA Appendix A Changes

In LRA Appendix A, a new Section 18.1.40, ASME Code Class 1 Small-bore Piping Inspection Program, is being added to read as follows:

18.1.40 ASME CODE CLASS 1 SMALL-BORE PIPING INSPECTION PROGRAM

The ASME Code Class 1 Small-Bore Piping Inspection Program is a plant-specific program that manages cracking of small-bore class 1 piping. Ten percent of Class 1 butt welds in piping of less than four inch NPS receive a volumetric examination each interval. Socket welds less than four inch NPS receive a VT-2 visual examination during pressure testing during each refueling outage.

In LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, a new commitment 45 is added as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
45.	ASME Class 1 Small-bore Piping Inspection Program	Implement an ASME Code Class 1 Small-bore Piping Inspection Program	18.1.40	Prior to the period of extended operation

In LRA Appendix A, Section 18.1.3, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program, on page A-4, the third paragraph, "NRC Generic Letter 88-01 required ... ASME Section XI Inservice Inspection Program." is deleted in its entirety.

LRA Appendix B Changes

In LRA Table B.2.2-1, Aging Management Program Correlation, on page B-10, the line item for XI.M35 - One-Time Inspection of ASME Code Class 1 Small Bore Piping is revised to appear as follows:

NUREG-1801 AGING MANAGEMENT PROGRAM	DUANE ARNOLD AGING MANAGEMENT PROGRAM	NUREG=1801 COMPARISON	NEW/ EXISTING PROGRAM
XI.M35 - One-Time Inspection of ASME Code Class 1 Small Bore Piping	Not credited for license renewal at Duane Arnold	Not Applicable	Not Applicable

In LRA Table B.2.2-1, Aging Management Program Correlation, on page B-11, add a new plant-specific program as follows:

NUREG-1801 AGING MANAGEMENT PROGRAM	DUANE ARNOLD AGING MANAGEMENT PROGRAM	NUREG=1801 COMPARISON	NEW/ EXISTING PROGRAM
Plant-Specific Program	ASME Code Class 1 Small-bore Piping Inspection Program	Not Applicable	New

In LRA Section B.3.3, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, Subsection B.3.3.1, Program Description, on page B-15, the last paragraph is revised in its entirety to read as follows:

This program manages the aging effect of cracking which includes stress corrosion cracking, intergranular stress corrosion cracking, and irradiation assisted stress corrosion cracking. DAEC has identified cracking in ASME Class 1 large bore piping.

In LRA Section B.3.12, BWR Stress Corrosion Cracking Program, Subsection B.3.12.1, Program Description, on page B-29, the last paragraph is revised in its entirety to read as follows:

DAEC has identified cracking in ASME Class 1 large bore piping.

<u>LRA Section 3.1 Changes</u>

In LRA Section 3.1.1.1, Nuclear Boiler, on page 3.1-2, under Aging Management Programs, a new bullet is added to read as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Section 3.1.1.2, Reactor Vessel Recirculation System, on page 3.1-4, under Aging Management Programs, a new bullet is added to read as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Table 3.1-1, Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 Reactor Coolant System, on page 3.1-19, in line item 3.1.1-48, the Discussion entry is revised to read as follows;

Consistent with NUREG-1801. At Duane Arnold, cracking in stainless steel components of the reactor coolant pressure boundary exposed to reactor coolant is managed by the ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program, Water Chemistry Program, and plant-specific program, ASME Code Class 1 Small-bore Piping Inspection Program.

In LRA Table 3.1.2-1, Summary of Aging Management Review Results Nuclear Boiler, on page 3.1-34, line item Flow orifice Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Flow orifice Class 1	Pressure boundary Throttle	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.1.2-1, Summary of Aging Management Review Results Nuclear Boiler, on page 3.1-48, line item Pipe Class 1, pipe fittings, tubing, with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.1.2-1, Summary of Aging Management Review Results Nuclear Boiler, on page 3.1-65, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.1.2-2, Summary of Aging Management Review Results Reactor Vessel Recirculation System, on page 3.1-70, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD and the Water Chemistry Programs, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary Throttle	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.1.2-2, Summary of Aging Management Review Results Reactor Vessel Recirculation System, on page 3.1-73, line item Valve Class 1 with Aging Effect Requiring Management of Cracking managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD and Water Chemistry Programs, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Cast Austenitic stainless steel	Reactor Coolant >250 °C (>482 °F) (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.1.2-2, Summary of Aging Management Review Results Reactor Vessel Recirculation System, on page 3.1-74, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In the Notes for Tables 3.1.2-1 Through 3.1.2-2, in the Plant-Specific Notes listing on page 3.1-78, note 237 is revised to read as follows:

237 DAEC has plant specific OE for cracking of small bore piping. Therefore, Program XI.M35 is not applicable to DAEC. At DAEC small bore piping is managed with a plant-specific program.

<u>LRA Section 3.2 Changes</u>

In LRA Section 3.2.1.1, Core Spray System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Section 3.2.1.2, High Pressure Coolant Injection System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Section 3.2.1.4, Reactor Core Isolation Cooling System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Section 3.2.1.5, Residual Heat Removal System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Table 3.2.2-1, Summary of Aging Management Review Results Core Spray System, on page 3.2-25, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking managed by the ASME Section XI, Subsection IWB, IWC and IWD and Water Chemistry Programs, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary Throttle	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-1, Summary of Aging Management Review Results Core Spray System, on page 3.2-28, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-2, Summary of Aging Management Review Results High Pressure Coolant Injection System, on page 3.2-33, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary Throttle	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-2, Summary of Aging Management Review Results High Pressure Coolant Injection System, on page 3.2-38, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-4, Summary of Aging Management Review Results Reactor Core Isolation Cooling System, on page 3.2-49, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary Throttle	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-4, Summary of Aging Management Review Results Reactor Core Isolation Cooling System, on page 3.2-53, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-5, Summary of Aging Management Review Results Residual Heat Removal System, on page 3.2-61, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Cast austenitic stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.2.2-5, Summary of Aging Management Review Residual Heat Removal System, on page 3.2-62, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In the Notes for Tables 3.2.2-1 Through 3.2.2-6, in the Plant-Specific Notes listing on page 3.2-72, note 237 is revised to read as follows:

237 DAEC has plant specific OE for cracking of small bore piping. Therefore, Program XI.M35 is not applicable to DAEC. At DAEC small bore piping is managed with a plant-specific program.

LRA Section 3.3 Changes

In LRA Section 3.3.1.19, Post-Accident Sampling System, on page 3.3-22 under Aging Management Programs, two new bullets are added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program
- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program

In LRA Section 3.3.1.24, Reactor Water Cleanup System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Section 3.3.1.30, Standby Liquid Control System, on page 3.3-33 under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Table 3.3.2-19, Summary of Aging Management Review Results Post Accident Sampling System, on page 3.3-176, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.3.2-19, Summary of Aging Management Review Results Post Accident Sampling System, on page 3.3-178, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.3.2-24, Summary of Aging Management Review Results Reactor Water Cleanup System, on page 3.3-204, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking managed by the ASME Section XI, Subsections IWB, IWC and IWD Programs, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.3.2-24, Summary of Aging Management Review Results Reactor Water Cleanup System, on page 3.3-207, line item Valve Class 1 with Aging Effect Requiring Management of Cracking managed by the ASME Section XI, Subsection IWB, IWC and IWD and Water Chemistry Programs, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.3.2-30, Summary of Aging Management Review Results Standby Liquid Control System, on page 3.3-251, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.3.2-30, Summary of Aging Management Review Standby Liquid Control System, on page 3.3-252, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In the Notes for Tables 3.3.2-1 Through 3.3.2-33, in the Plant-Specific Notes listing on page 3.3-268, note 237 is revised to read as follows:

237 DAEC has plant specific OE for cracking of small bore piping. Therefore, Program XI.M35 is not applicable to DAEC. At DAEC small bore piping is managed with a plant-specific program.

<u>LRA Section 3.4 Changes</u>

In LRA Section 3.4.1.4, Main Steam Isolation and Automatic Depressurization System, under Aging Management Programs, a new bullet is added as follows:

- ASME Code Class 1 Small-Bore Piping Inspection Program

In LRA Table 3.4.2-4, Summary of Aging Management Review Results Main Steam Isolation and Automatic Depressurization System, on page 3.4-52, line item Flow orifice Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Flow orifice Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.4.2-4, Summary of Aging Management Review Results Main Steam Isolation and Automatic Depressurization System, on page 3.4-53, line item Pipe Class 1, pipe fittings, tubing with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Pipe Class 1, pipe fittings, tubing	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In LRA Table 3.4.2-4, Summary of Aging Management Review Results Main Steam Isolation and Automatic Depressurization System, on page 3.4-55, line item Valve Class 1 with Aging Effect Requiring Management of Cracking, is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Valve Class 1	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-1 (R-03)	3.1.1-48	A
					ASME Code Class 1 Small-bore Piping Inspection Program	IV.C1-1 (R-03)	3.1.1-48	237, E

In the Notes for Tables 3.4.2-1 Through 3.4.2-5, in the Plant-Specific Notes listing on page 3.4-74, note 237 is revised to read as follows:

237 DAEC has plant specific OE for cracking of small bore piping. Therefore, Program XI.M35 is not applicable to DAEC. At DAEC small bore piping is managed with a plant-specific program.

RAI B.3.3-3

Background

In the DAEC LRA Section B.3.3, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program," the applicant stated that the AMP is "consistent with the ten elements of NUREG-1801, Section XI.M1."

Issue

The program documents submitted do not include operating experience. The staff finds it difficult to evaluate the sufficiency of the AMP in the absence of operating experience.

Request

Please provide DAEC plant-specific operating experience related to the Section XI, IWB, IWC, and IWD Program. Please also provide operating experience related to Code Class 1 small bore piping.

DAEC Response to RAI B.3.3-3

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program inspects numerous components each refueling outage. Reports are filed with the NRC to document the inspections. Generally, because of the high quality of nuclear materials and construction, these inspections do not find large numbers of indications of significant defects. Examples of typical inspection results include the following:

Refueling Outage 18 Inspection Results
The Refueling Outage (RFO) 18 Inservice Inspection Summary Reports, submitted to the NRC on July 18, 2003, indicated that 23 examinations were performed for the second inspection period. All of the examinations results were acceptable. There were also approximately 37 examinations performed for the third inspection interval. All of the examination results were acceptable.

Refueling Outage 19 Inspection Results
Refueling Outage (RFO) 19 Inservice Inspection Summary Reports submitted to the NRC on July 29, 2005, indicated that approximately 125 examinations were performed. Of these examinations, all were acceptable except one which was accepted by replacement. CAP 036901 was written for deformed threads on one (1) bolt removed from CRD 1R215 (34-07). Of the eight bolts removed from CRD 1R215, one bolt was found to have deformed threads. It was determined that the deformed threads most likely occurred during disassembly. All eight bolts were replaced and the removed bolts were disposed of.

<u>Refueling Outage 20 Inspection Results</u>

Refueling Outage (RFO) 20 Inservice Inspection Summary Reports submitted to the NRC on June 12, 2007, indicated that approximately 75 examinations were accepted with no evaluations required. Nozzle to Safe End welds RRC-F002 and RRF-F002 were rejected and were repaired by weld overlay. This was reported to the NRC by Licensee Event Report (LER #2007-03-00) submitted in accordance with 10 CFR 50.73.

<u>Refueling Outage 21 Inspection Results</u>

The summary report for Duane Arnold Energy Center during Cycle 21 operations and Refueling Outage (RFO) No. 21 was submitted to the NRC on May 29, 2009. This report states that no indications were found that required evaluation for continued service.

For operating experience associated with Small-Bore Code Class 1 Piping, see the response to RAI B.3.3-2.

RAI B.3.4-1

Background

GALL Report (NUREG-1801), Element 5 of the AMP X1.S1, "ASME Section XI, Subsection IWE," require that areas containing flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

Issue

LRA Section B.3.4, "ASME Section XI Inservice Inspection, Subsection IWE Program," states that this program is consistent with NUREG-1801 (GALL) AMP XI.S1. Section 3.5 of the DAEC program basis document (LRAP-S001, Rev. 2) further states that Monitoring and Trending element for LRAP-0001 is consistent with 2001 Edition, including the 2002 and 2003 Addenda, of ASME Section XI, Subsection IWE which fulfills the requirements of NUREG-1801 XI.S1, Element 5, "Monitoring and Trending." However, Section 3.5.2 of LRAP-S001 states that:

"When the reexaminations required by IWE-2420(b) reveal that the flaws or areas of degradation remain essentially unchanged for the next inspection period, these areas no longer require augmented examination in accordance with Table IWE-2500-1, Examination Category E-C."

Request

Explain how Section 3.5 of the LRAP-S001, Rev. 2 and the LRA Section B.3.4 are consistent with the GALL AMP XI.S1, Element 5.

DAEC Response to RAI B.3.4-1

Section 3.5 of the program basis document and LRA Section B.3.4 are consistent with the NUREG-1801 XI.S1 because they are consistent with the requirements of ASME Code Section XI, 2001 edition including the 2002 and 2003 Addenda as approved in 10CFR 50.55a. This is the version of the code endorsed by NUREG-1801, Rev 1 for XI.S1 ASME Section XI, Subsection IWE. In the ASME Section XI, 2001 edition including the 2002 and 2003 Addenda, Section IWE-2420 "Successive Inspection" paragraph (c) states:

> "When the reexaminations required by IWE-2420(b) reveal that the flaws or areas of degradation remain essentially unchanged for the next inspection period, these areas no longer require augmented examination in accordance with Table IWE-2500-1, Examination Category E-C."

The statement in question in NUREG-1801 Rev 1 is clearly in error as it is inconsistent with the endorsed ASME Code edition and addenda. The statement appears to be an artifact of program XI.S1 in NUREG-1801 Rev 0 which only endorsed the ASME Code, Section XI, 1992 edition with the 1992 Addenda and the 1995 Edition with the 1996 Addenda. The 1995 IWE -2420 "Successive Inspection" paragraph (c) states;

> "When the reexaminations required by IWE-2420(b) reveal that the flaws or areas of degradation or areas subjected to a repair/replacement activity, remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Table IWE-2500-1, Examination category E-C."

The program XI.S1 description in NUREG-1801 Rev 0, Monitoring and Trending, reflected this code criterion by stating the following.

> "When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C".

Since the NUREG-1801 Rev 1 program XI.S1 now endorses the 2001 Edition including the 2002 and 2003 Addenda without exception, the correct standard is that augmented examinations may be discontinued if the flaws or areas of degradation remain essentially unchanged for the next inspection period. Having the statement from the earlier code edition in element 5 is viewed as an oversight that is superseded by the actual language of the endorsed code. The statement is not viewed as supplementary guidance that takes exception to the language of Section IWE-2420 as approved by 10 CFR 50.55a and endorsed elsewhere in the program description of NUREG 1801 program XI.S1 ASME Section XI, Subsection IWE.

RAI [B.]3.4-2

Background

GALL Report (NUREG-1801), Element 5 of the AMP X1.S1, "ASME Section XI, Subsection IWE," require that areas containing flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

Issue

DAEC document LRAP-S001, Rev. 2, "ASME Section XI Inservice Inspection Subsection IWE," references DAEC Station 2nd Interval Containment Inspection Plan. This inspection plan contains Relief Request No. MC-R001 which has different requirements for augmented examinations (twice during 10 year interval) than GALL report AMP XI.S1. Relief Request MCR001 has been approved by the NRC for the period between May 2008 and February 2014.

Request

Explain how the relief request MC-R001 is consistent with GALL Element 5. In addition, provide documentation that this relief request has been approved by the USNRC for the period of extended operation.

DAEC Response to RAI [B.]3.4-2

The current DAEC Station Containment Inspection Plan will be effective through and including February 21, 2014, which corresponds with the end of the current license period. The ASME Section XI, IWE Program is in its second interval. The relief request MC-R001 is only approved for the second interval. During the period of extended operation, the inspection requirements for Category E-C will be performed, unless approval has been granted by the NRC for relief or use of alternatives, in accordance with 10 CFR 50.55a.

RAI [B.]3.4-3

Background

ASME Subsection IWE, Subarticle IWE-5240 requires that during the pressure test required by IWE-5220, a detailed visual examination (IWE-2310) shall be performed on areas affected by repair/replacement activities.

Issue

DAEC Station 2nd Interval Containment Inspection Plan contains a copy of the relief request MC-P001 which requests relief from performing detailed VT-1 examination for minor repairs prior to performing pneumatic tests conducted in accordance with 10 CFR 50, Appendix J in lieu of IWE 5420. Relief Request MC-P001 has been approved by the NRC for the period between May 2008 and February 2014.

Request

Explain how relief request MC-P001 for not performing VT1 examination is consistent with GALL AMP XI S.1. In addition, provide documentation that this relief request has been approved by the USNRC for the period of extended operation.

DAEC Response to RAI [B.]3.4-3

The DAEC Station 2nd Interval Containment Inspection Plan will be effective through and including February 21, 2014 and corresponds with the end of the current license period. The relief request MC-P001 is only approved for the second interval. During the period of extended operation, the detailed visual examination of IWE-5240 will be performed following all repairs, replacements or modifications, unless approval has been granted by the NRC for relief or use of alternatives, in accordance with 10 CFR 50.55a.

RAI [B.]3.4-4

Background

GALL Report (NUREG-1801), Element 5 of the AMP X1 S.1, "ASME Section XI, Subsection IWE," require all accessible surfaces be monitored by virtue of examination on a scheduled basis.

Issue

A review of various Corrective Action Program (CAP) Reports, including CAP 0611106, and RFP No. 20 inspection report of the torus indicate that DAEC does not maintain a database of the all degradations observed over the life of the plant.

Request

Explain how DAEC maintain the records of degradations and repairs of the torus internal surface to ensure that the effects of aging on the torus will be adequately managed for the period of extended operation.

DAEC Response to RAI [B.]3.4-4

DAEC maintains relevant documentation for torus inspections which include photographs, inspection reports and completed checklists, records of corrective actions and other follow-up information as Quality Assurance Records. These records are available to support aging management of the torus during the period of extended operation. The following examples of procedural requirements illustrate the documentation resulting from torus inspections.

The surveillance test procedure for Suppression Chamber and Drywell visual inspection implements the drywell and torus surface inspection requirements. Torus Interior inspection checklists provide the scope of the visual inspections for all 16 bays, defines inspection criteria, requires a review of previously performed inspection results and requires documentation of current inspection results, including observed suspect areas. The procedure specifies that documentation should include photographs with noted deficiencies tracked by appropriate documentation (Work Orders, Action Requests) to track resolution.

The surveillance test procedure for visual examination of submerged areas of the Suppression Chamber implements requirements for performing and documenting visual examinations of the submerged portions of the suppression chamber (torus and downcomers) for evidence of deterioration. Torus underwater inspections are performed by specialty contractors. The inspections and repairs are documented in the contractor report and in the procedure. Additionally, the contractor videotapes the initial and final inspections. Historical reports and videotapes are available for review during the inspections and repairs.

RAI [B.]3.4-5

Background

GALL report AMP XI S8, Element 1 requires proper maintenance of protective coatings inside containment (defined as Service Level I in Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev. 1) in order to ensure operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of strainers, which reduces flow through the sump/drain system. Maintenance of Service Level I coatings applied to carbon steel surfaces inside containment (e.g., steel liner, steel containment shell, penetrations, hatches) also serves to prevent or minimize loss of material due to corrosion.

Issue

DAEC document, "ASME Section XI, Subsection IWE, LRAP-S001, Rev. 2" references DAEC procedure STP 3.6.1.1-01, "Surveillance Test Procedure, Suppression Chamber and Drywell Inspection," for inspection of the ASME Subsection IWE inspection. DAEC document STP 3.6.1.1-01 states that the design basis for inspection and repair of the coatings in the Drywell and Suppression Pool is described in ACP 1601 and ACP 1603. According to ACP 1601, all exposed coatings within containment that in the event of a DBA-LOCA could dislodge and be carried down to the torus where it could block essential ECCS suction strainers are considered safety-related, Service Level I, with regards to DAEC Protective Coating Program (PCP), both in the vapor area and those in immersion service. In addition, according to the DAEC PCP, coatings in the torus area are used to prevent corrosion.

Request

Explain why there is no AMP for safety-related, Service Level 1 coatings applied to the torus area. In addition, justify why NUREG-1801 AMP XI S.8 does not apply to DAEC.

DAEC Response to RAI [B.]3.4-5

While the presence of coatings can prevent corrosion, the DAEC License Renewal evaluations do not credit coatings for the function of preventing corrosion. The inspection and assessment of the condition of coatings inside containment and the torus are performed to confirm that the potential volume of debris would remain within design assumptions, and are not for the management of aging in coatings. These activities do not prevent coating failures, and are used only to minimize debris that could be generated during a LOCA to mitigate the potential for ECCS strainer clogging. Therefore, NUREG-1801 AMP XI.S8 is not applicable as an aging management program for DAEC.

RAI B.3.6-01

Background

For DAEC AMP B.3.6, the FSAR Supplement in LRA Appendix A.18.1.6 states, in part, "The Bolting Integrity Program credits three separate AMPs for the inspection of bolting. The four AMPs are: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program, (2) ASME Section XI Inservice Inspection Subsection IWF, (3) External Surface Monitoring Program, and (4) Structural Monitoring Program."

The DAEC program basis document for the Bolting Integrity Program states that five (5) programs are credited and lists the following programs: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program, (2) ASME Section XI Inservice Inspection Subsection IWF, (3) External Surface Monitoring Program, (4) Structural Monitoring Program, and (5) Buried Piping and Tanks Inspection Program.

In addition, LRA Section B.3.6, Bolting Integrity Program, does not list the Buried Piping and Tanks Inspection Program as an AMP where inspection of bolting is also credited in the Bolting Integrity Program.

Issue

The list of credited programs in the FSAR Supplement and in LRA Section B.3.6 does not match the list of credited programs in the program basis document for the DAEC Bolting Integrity Program. Additionally the number of programs stated at one place in the FSAR Supplement is not the same as listed at another place in the FSAR Supplement.

Request

Revise the documentation discrepancy.

DAEC Response to RAI B.3.6-01

In LRA Appendix A, Section 18.1.6, on page A-5, the last two sentences of the first paragraph are revised to read as follows:

> The Bolting Integrity Program credits five separate aging management programs for the inspection of bolting. The five aging management programs are: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, (2) ASME Section XI Inservice Inspection, Subsection IWF Program, (3) External Surfaces Monitoring Program, (4) Structural Monitoring Program, and (5) Buried Piping and Tanks Program.

In LRA Section B.3.6.1 on pages B-19 and B-20, the third paragraph is revised in its entirety to read as follows:

The Bolting Integrity Program credits the following aging management programs for the inspection of bolting: (1) ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program, (2) ASME Section XI Inservice Inspection Subsection IWF Program, (3) External Surfaces Monitoring Program, (4) Structural Monitoring Program, and (5) Buried Piping and Tanks Program. The scopes of the credited programs for bolting are summarized below:

- The DAEC ASME Section XI Inservice Inspection Program provides the requirements for inservice inspection of ASME Class 1, 2, and 3 piping and their integral attachments, which includes pressure retaining bolting.
- The DAEC ASME Section XI Subsection IWF Program provides the requirements for inspection of ASME Class 1, 2, and 3 support bolting.
- The DAEC External Surfaces Monitoring Program provides the requirements for the inspection of bolting for steel components such as piping, piping components, ducting and other components within the scope of license renewal.
- The DAEC Structural Monitoring Program provides the requirements for the inspection of all structural support bolting within the scope of license renewal. Other bolting and fasteners are also included within the scope of this program, such as those used in supports for cable trays, conduits, and cabinet supports.
- The DAEC Buried Piping and Tanks Program provides the requirements for inspection of bolting and fasteners in buried piping and tanks.

RAI B.3.6-02

Background:

LRA Section B.3.6 states that the Bolting Integrity Program credits inspections of fasteners, bolting, washers and nuts performed under other AMPs. The DAEC Program Basis Document states that the following five (5) AMPs are credited for inspection of fasteners, bolting, washers and nuts: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program, (2) ASME Section XI Inservice Inspection Subsection IWF, (3) External Surface Monitoring Program, (4) Structural Monitoring Program, and (5) Buried Piping and Tanks Inspection Program.

Issue

The staff does not have sufficient information, nor a commitment, to ensure that inspections of fasteners, bolting, washers and nuts performed under the five (5) listed AMPs are equivalent to the bolting inspections recommended in the GALL Report for AMP XI.M18, "Bolting Integrity."

Request

1. Provide a commitment to include inspection of fasteners, bolting, washers and nuts as a specific activity in each of the five (5) listed AMPs.
2. Provide justification that the inspection of fasteners, bolting, washers and nuts performed under the five (5) listed AMPs are equivalent to the inspection of fasteners, bolting, washers and nuts recommended in GALL AMP XI.M18 with regard to program element 3, "Parameters Monitored/Inspected," and element 4, "Detection of Aging Effects."

DAEC Response to RAI B.3.6-02

Part 1

LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is hereby revised to incorporate the following new commitment:

Item No.	System, Component or Program	Commitment	Section	Schedule
41.	Bolting Integrity Program	Revise the implementing procedures for the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program; ASME Section XI Inservice Inspection, Subsection IWF Program; External Surfaces Monitoring Program; Structural Monitoring	18.1.6	Prior to the period of extended

		Program; and Buried Piping and Tanks Program such that they specifically address the inspection of fasteners (bolting, washers, nuts, etc.) for signs of leakage, corrosion/loss of material, cracking, and loss of preload/loss of prestress, as applicable.		operation

Part 2

The language used in the commitment is equivalent to the wording in NUREG-1801.

RAI B.3.6-03

Background

LRA Section B.3.6 states that the Bolting Integrity Program credits inspections of bolting performed under other AMPs. The DAEC Program Basis Document states that the following five (5) AMPs are credited for inspection of bolting: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program, (2) ASME Section XI Inservice Inspection Subsection IWF, (3) External Surface Monitoring Program, (4) Structural Monitoring Program, and (5) Buried Piping and Tanks Inspection Program.

For the Emergency Service Water System (LRA Table 3.3.2-10), the Fire Protection System (LRA Table 3.3.2-11), the Intake and Traveling Screens (LRA Table 3.3.2-16), the RHR Service Water System (LRA Table 3.3.2-25), and the River Water Supply System (LRA Table 3.3.2-26), the LRA includes aging management review (AMR) result lines in which the Bolting Integrity Program is credited with managing the aging effect of loss of material in carbon steel and stainless steel fasteners, bolting, washers and nuts where the environment is raw water (external).

Issue

The staff does not have sufficient information to determine which of the five AMPs listed in the DAEC Program Basis Document for the Bolting Integrity Program is credited for performing inspections of fasteners, bolting, washers and nuts in a raw water environment.

Request

1) For each system in which the LRA credits the Bolting Integrity Program to manage loss of material in carbon steel or stainless steel fasteners, bolting, washers and nuts in a raw water environment, identify the AMP under which the inspection for loss of material in fasteners, bolting, washers and nuts is actually performed.

2) Provide justification that the inspection of fasteners, bolting, washers and nuts performed under the identified AMP(s) is equivalent to the inspection of fasteners, bolting, washers and nuts recommended for these components in GALL AMP XI.M18, "Bolting Integrity."

DAEC Response to RAI B.3.6-03

Part 1

The aging management program under which the inspection for loss of material in fasteners, bolting, washers and nuts in a raw water environment for the Emergency Service Water System (ASME Class 3) and the RHR Service Water System (ASME Class 3) is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

The Balance-of-Plant Systems, Fire Protection System (National Fire Protection Code), the River Water Supply System (B31.1.0), and the Intake and Traveling Screens, are inspected in accordance with NUREG -1801-XI.M18, Detection of Aging Effects, "For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before leakage becomes excessive." These inspections are conducted under the External Surfaces Monitoring Program.

Part 2

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program is an existing program that performs inspections to identify and correct degradation in Class 1, 2, and 3 piping, components, their supports and integral attachments. The program includes periodic visual, surface and/or volumetric examinations of all Class 1, 2 and 3 pressure-retaining components, their supports and integral attachments, including welds, pump casings, valve bodies, pressure-retaining bolting, and piping/component supports and leakage tests of pressure retaining components. NUREG-1801 XI.M18 explicitly recognizes the validity of ASME Code inspection requirements for fasteners.

The Duane Arnold Energy Center (DAEC) External Surfaces Monitoring program is an existing program that manages aging effects through visual inspection of external surfaces for evidence of material loss. The program consists of periodic inspections of components such as piping, piping components, ducting, pipe supports and other components within the scope of license renewal and subject to AMR in order to manage aging effects.

The External Surfaces Monitoring Program utilizes periodic plant system inspections and walkdowns to monitor for material degradation and leakage. This program inspects components such as piping, piping components, ducting and other components. Examples of inspection parameters identified in the program basis document include:

- corrosion and material wastage (loss of material);
- loss of support bolts
- flange leaks, loose bolting
- leakage from or onto external surfaces;
- worn, flaking, or oxide-coated surfaces;
- corrosion stains on thermal insulation;
- protective coating degradation (cracking and flaking)

These inspections satisfy the wording in the GALL that states periodic system walkdowns assure detection of leakage before leakage becomes excessive.

RAI B.3.7-1

Background

The applicant states that its LRA AMP Buried Piping and Tanks Inspection (B.3.7) is consistent with the GALL Report AMP, Buried Piping and Tanks Inspection (XI.M34). In its audit of program element 1 (scope), the staff identified a potential inconsistency between the LRA AMP and the GALL Report AMP.

Issue

Program element 1 of the GALL Report AMP, scope, states that the scope of the AMP includes buried steel piping and tanks. Chapter IX of Volume 2 of the GALL report states that the term "steel" includes carbon steel, low alloy steel and cast iron. The term "steel" does not include stainless steel. Program element 1 of the LRA AMP states that the scope of the program includes carbon steel, low alloy steel, and stainless steel. The scope of the LRA AMP does not appear to include cast iron although cast iron components appear to be present in systems addressed by this AMP. Given that the corrosion characteristics of stainless steel are different than steel (as defined in the GALL Report) and that the procedures for adequately managing aging may, therefore, be different, the inclusion of stainless steel in this AMP must be considered an exception to the GALL AMP.

Request

Please commit to revise the LRA AMP to show the inclusion of stainless steel buried piping as an exception. Additionally please justify why the proposed program is sufficient to manage the aging of stainless steel pipe. Also, please modify the scope of the LRA AMP to specifically include cast iron.

DAEC Response to RAI B.3.7-1

LRA Section B.3.7, Buried Piping and Tanks Inspection Program, on pages B-20 and B-21, is revised in its entirety to read as follows:

B.3.7 BURIED PIPING AND TANKS INSPECTION PROGRAM

B.3.7.1 PROGRAM DESCRIPTION

The DAEC Buried Piping and Tanks Inspection Program is a new program. The program manages the aging effects of corrosion on the pressure-retaining capacity of buried piping and tanks.

In-scope buried carbon and low-alloy steel piping and tanks have external coatings and wrappings. In-scope buried cast iron and stainless steel piping does not have external coatings and wrappings.

The program includes provisions for visual inspections of the protective wraps and coatings on buried carbon, and low-alloy steel, piping and tanks in-scope for license renewal. The program also includes provisions for inspections for loss of material on buried uncoated cast iron and stainless steel piping in-scope for license renewal. The inspections for damage and loss of material are performed when the carbon, low alloy, uncoated cast iron and uncoated stainless steel pipes and tanks are excavated and exposed for any reason.

If damage to the protective wraps and coatings of carbon and low-alloy steel is found, the outer surface of the pipe or tank is inspected for loss of material due to general corrosion, pitting, and crevice corrosion, and Microbiologically-Influenced Corrosion (MIC). Buried stainless steel will be inspected for loss of material due to pitting, crevice corrosion, and MIC. Buried cast iron pipe will be evaluated for general, pitting, crevice corrosion, and MIC.

At DAEC buried pipes and tanks are not routinely uncovered during maintenance activities. However, the program requires that at least one opportunistic or focused inspection be performed prior to entering the period of extended operation. Inspections will be performed at least once every 10 years thereafter.

B.3.7.2 NUREG-1801 CONSISTENCY

This program is consistent with nine of the ten elements of NUREG-1801 XI.M34. One exception is taken that affects "Scope of Program." The exception is described below.

B.3.7.3 EXCEPTIONS TO NUREG-1801

The DAEC program takes one exception to the guidance as stated in NUREG-1801 XI.M34. This exception affects the following elements of NUREG-1801 XI.M34.

- Scope of Program

  NUREG-1801 states: The program relies on preventive measures such as coating, wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried steel piping and tanks.

  The DAEC program will expand the NUREG-1801 XI.M34 requirements for inspection of coated pipes to include inspections for loss of material of uncoated cast iron and stainless steel pipes.

B.3.7.4 ENHANCEMENTS TO DUANE ARNOLD PROGRAM

This program does not require any enhancements to be consistent with the ten elements of NUREG-1801 XI.M34.

B.3.7.5 OPERATING EXPERIENCE

The DAEC Buried Piping and Tanks is a new program; therefore, there is no plant specific program operating experience. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. Industry operating experience will be evaluated in the development and implementation of this program. As additional operating experience is obtained, lessons learned will be appropriately incorporated into the program.

B.3.7.6 CONCLUSION

The Buried Piping and Tanks Inspection Program is a new program that provides reasonable assurance that the effects of aging as defined in NUREG-1801 XI.M34 will be managed consistent with the current licensing basis for the period of extended operation.

To reflect this revised program description, the following additional LRA changes are being made.

In LRA Appendix A, Section 18.1.7, Buried Piping and Tanks inspection Program, on page A-5, is revised in its entirety to read as follows:

18.1.7 BURIED PIPING AND TANKS INSPECTION PROGRAM

The Buried Piping and Tanks Inspection Program includes provisions for visual inspections of the protective wraps and coatings on buried carbon and low-alloy steel, piping and tanks and visual inspections of external surfaces of cast iron and stainless steel pipe in-scope for license renewal. The visual inspections for damage are performed when the carbon, low-alloy, cast iron and stainless steel components are excavated during maintenance and when a component is dug up and inspected for any reason. If damage to the protective wraps and coatings of carbon and low-alloy steel is found, the outer surface of the pipe or tank is inspected for loss of material. This DAEC program contains inspections for buried pipe that is not coated. Uncoated cast iron and stainless steel piping will be inspected for loss of material.

The Program is consistent with the ten elements of NUREG-1801 XI.M34 with exceptions. The Program includes inspections for loss of material of uncoated cast iron and stainless steel pipes.

LRA Section 3.2.2.2.9, Loss of Material Due to General, Pitting, Crevice Corrosion, and Microbiologically Influenced Corrosion (MIC), on page 3.2-11, is revised in its entirety to read as follows:

> Loss of material due to general, pitting, crevice corrosion, and Microbiologically Influenced Corrosion (MIC) could occur for steel (with or without coating or wrapping), uncoated cast iron and stainless piping, piping components, and piping elements buried in soil. At Duane Arnold, loss of material for steel, cast iron and stainless components with an external environment of soil is being managed by the Buried Piping and Tanks Inspection Program. The Buried Piping and Tanks Inspection Program will manage the aging effect of loss of material such that the intended function of the components will not be affected.

In LRA Table 3.2-1, Summary of Aging Management Evaluations in Chapter V of NUREG-1801 Engineered Safety Features, in line item 3.2.1-17, the Discussion entry is revised to read, "Consistent with NUREG-1801 with exceptions. Further evaluation is provided in LRA Subsection 3.2.2, NUREG-1800 Section 3.2.2.2.9."

In LRA Table 3.2.2-2, Summary of Aging Management Review Results High Pressure Coolant Injection System, on page 3.2-36, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from 202, A to 202, B.

In LRA Table 3.2.2-6, Summary of Aging Management Review Results Standby Gas Treatment System, on page 3.2-67, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

LRA Section 3.3.2.2.8, Loss of Material Due to General, Pitting, Crevice Corrosion, and Microbiologically-Influenced Corrosion (MIC), on page 3.3-39, is revised in its entirety to read as follows:

> Loss of material due to general, pitting, crevice corrosion, and Microbiologically Influenced Corrosion (MIC) could occur for steel (with or without coating or wrapping), uncoated cast iron and stainless piping, piping components, and piping elements buried in soil. At Duane Arnold, loss of material for steel, cast iron and stainless components with an external environment of soil is being managed by the Buried Piping and Tanks Inspection Program. The Buried Piping and Tanks Inspection Program will manage the aging effect of loss of material such that the intended function of the components will not be affected.

In LRA Table 3.3-1, Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 Auxiliary Systems, in line item 3.3.1-19, the Discussion entry is revised to read, "Consistent with NUREG-1801 with exceptions. Further evaluation is provided in LRA Subsection 3.3.2, NUREG-1800 Section 3.3.2.2.8."

In LRA Table 3.3.2-10, Summary of Aging Management Review Results Emergency Service Water system, on page 3.3-125, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

In LRA Table 3.3.2-11, Summary of Aging Management Review Results Fire Protection System, on pages 3.3-138 and 3.3-139, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B. This change is also made for line item Valve, Damper which cites the Buried Piping and Tanks Inspection Program on page 3.3-143.

In LRA Table 3.3.2-25, Summary of Aging Management Review Results RHR Service Water System, on page 3.3-211, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

In LRA Table 3.3.2-26, Summary of Aging Management Review Results River Water Supply System, on pages 3.3-214, for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

In LRA Table 3.3.2-29, Summary of Aging Management Review Results Standby Diesel Generators, on page 3.3-228 for line item Accumulator, pulsation damper, low pressure tank which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

In LRA Table 3.3.2-29, Summary of Aging Management Review Results Standby Diesel Generators, on page 3.3-238 for line item Pipe, pipe fittings, hoses, tubes, rupture disk which cites the Buried Piping and Tanks Inspection Program, the Notes entry is changed from A to B.

LRA Section 3.4.2.2.5, Loss of Material Due to General, Pitting, Crevice and Microbiologically-Influenced Corrosion, Part 1, on page 3.4-9, is revised in its entirety to read as follows:

1. Loss of material due to general, pitting, crevice corrosion, and Microbiologically Influenced Corrosion (MIC) could occur for steel (with or without coating or wrapping), uncoated cast iron and stainless piping, piping components, and piping elements buried in soil. At Duane Arnold, loss of material for steel, cast iron and stainless components with an external environment of soil is being managed by the Buried Piping and Tanks Inspection Program. The Buried Piping and Tanks Inspection Program will manage the aging effect of loss of material such that the intended function of the components will not be affected.

In LRA Table 3.4-1, Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 Steam and Power Conversion Systems, in line item 3.4.1-11, the Discussion entry is revised to read, "Consistent with NUREG-1801 with exceptions. Further evaluation is provided in LRA Subsection 3.4.2, NUREG-1800 Section 3.4.2.2.5, Item 1."

RAI B.3.7-2

Background

The applicant states that its LRA AMP Buried Piping and Tanks Inspection (B.3.7) is consistent with the GALL Report AMP, Buried Piping and Tanks Inspection (XI.M34). In its audit of program element 2 (preventive actions), the staff identified a potential inconsistency between the LRA AMP and the GALL Report AMP.

Issue

Program element 2 of the GALL Report AMP, preventive actions, states that underground piping and tanks are coated. Program element 2 of the LRA AMP states that carbon and low alloy steel pipes are coated. Elsewhere in the LRA AMP it is stated that stainless steel pipes are not coated. From the LRA AMP, it is not clear whether cast iron pipes are coated. Given that the corrosion rate of uncoated pipe exceeds that of coated pipe and that the GALL report AMP is designed for coated pipe, it is not clear that the LRA AMP, which claims consistency with the GALL AMP, will adequately manage aging. The absence of coatings must, therefore be considered an exception to the GALL AMP.

Request

Please clarify whether buried cast iron pipes are coated. Please commit to revise the LRA AMP to show the inclusion of uncoated buried piping as an exception. Additionally please justify why the proposed program is sufficient to manage the aging of uncoated stainless steel and/or cast iron pipes.

DAEC Response to RAI B.3.7-2

Buried cast iron pipe is not coated. See the response to RAI B.3.7-1 for LRA changes made to the Buried Piping and Tanks Program.

The DAEC Buried Piping and Tanks Program monitors the integrity of coating and wrapping on carbon and low alloy pipes and tanks by requiring an opportunistic visual inspection when they are excavated for any reason. The buried carbon and low alloy pipes and tanks are inspected for evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage when access becomes available. The program recognizes that damage to these protective barriers may be a possible indicator of corrosion to the outer surface of the buried component. For this reason, the program also includes an inspection for loss of material due to general corrosion, pitting, crevice corrosion, and Microbiologically Influenced Corrosion (MIC) in the vicinity of the damaged area. Buried uncoated stainless steel pipe will be inspected for loss of material due to pitting, crevice corrosion, and MIC. Buried uncoated cast iron pipe will be evaluated for general, pitting, crevice corrosion, and MIC.

RAI B.3.7-3

Background

The applicant states that its LRA AMP, Buried Piping and Tanks Inspection (B.3.7) is consistent with the GALL Report AMP, Buried Piping and Tanks Inspection (XI.M34). In its audit of program element 4 (detection of aging effects), the staff identified a potential inconsistency between the LRA AMP and the GALL Report AMP.

Issue

Section A.1.2.3.4 of the SRP-LR states that the program element "detection of aging effects" should contain information concerning the frequency, extent, sample size and methods used to detect aging. The staff notes that much of this information is absent from this section of the LRA AMP. In order for the staff to evaluate the consistency of this LRA program element with the corresponding GALL Report program element, it is necessary that the applicant provide additional information concerning the program for detection of aging effects.

Request

Please provide additional details of the proposed inspection program.

DAEC Response to RAI B.3.7-3

See the response to RAI B.3.7-1 for LRA changes made to the Buried Piping and Tanks Program.

The DAEC Buried Piping and Tanks Program consists of inspection activities that are designed to detect degradation due to aging effects prior to loss of intended function. For carbon and low alloy steel piping and tanks, opportunistic or focused visual inspections are performed to confirm that coating and wrapping are intact. Buried uncoated cast iron and stainless steel pipes will be visually inspected for loss of material. In-scope buried piping and tanks at DAEC will have an opportunistic inspection whenever they are excavated for any reason. The inspections are performed in areas with the highest likelihood of corrosion problems based on plant operating experience, within the areas made accessible to support the maintenance activity. The length of pipe included in the inspection will be based on multiple factors. The excavation site will be in compliance with DAEC safety procedures which invoke OSHA requirements for Trenching and Excavation Safety. Compliance with the safety requirements will ensure that an adequate length of pipe will be exposed to perform the inspection. Additionally the excavation will be of sufficient depth to allow for examination underneath the pipe.

The program requires that at least one opportunistic or focused inspection be performed prior to entering the period of extended operation. Opportunistic and/or focused visual inspections will be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems.

RAI B.3.7-4

Background

The applicant states that its LRA AMP, Buried Piping and Tanks Inspection (B.3.7) is consistent with the GALL Report AMP, Buried Piping and Tanks Inspection (XI.M34). In its audit of program element 6 (acceptance criteria), the staff identified a potential inconsistency between the LRA AMP and the GALL Report AMP.

Issue

Section A.1.2.3.6 of the SRP-LR states that the program element "acceptance criteria" should contain information concerning the acceptance criteria against which the need for corrective action will be measured. This section of the SRP-LR also states that the acceptance criteria should consist of numerical values or methods by which they are determined. The staff notes that this information is absent from this section of the LRA AMP. In order for the staff to evaluate the consistency of this LRA program element with the corresponding GALL Report program element, it is necessary that the applicant provide this information in the LRA AMP.

Request

Please provide acceptance criteria as indicated in the SRP-LR.

DAEC Response to RAI B.3.7-4

See the response to RAI B.3.7-1 for LRA changes made to the Buried Piping and Tanks Program.

Coating and wrapping degradation, or components identified with significant corrosion, will be documented and evaluated under the Corrective Action Program, which includes provisions for a root cause analysis, if appropriate. Evaluations performed as part of the Corrective Action Program may include use of applicable acceptance criteria of existing DAEC procedures such as the Corrosion Monitoring Program Manual for the Service Water and Fire Protection Monitoring Program.

RAI B.3.8-01

Background

GALL AMP XI.M6, BWR Control Rod Drive Return Line Nozzle (CRDRL), endorses the recommendations described in NUREG-0619. In GALL AMP XI.M6, the Preventive Actions program element states that mitigation occurs by system modifications such as rerouting the CRDRL to a system that connects to the reactor vessel and that, for some classes of BWRs, mitigation is accomplished by cutting and capping the CRDRL nozzle without rerouting.

Issue

The DAEC modifications do not appear to be one of the modification options described in NUREG-0619.

Request

Explain why the DAEC modifications, if different from the options described in NUREG-0619, are not considered an exception to the recommendations in GALL AMP XI.M6, Preventive Actions program element.

DAEC Response to RAI B.3.8-01

The mitigation option selected for the control rod drive return line (CRDRL) was to install a blind flange in the line rather than to permanently cut and cap the line as stated in NUREG-1801 XI.M6, BWR Control Rod Drive Return line Nozzle, under Preventive Actions. This mitigation strategy was specifically approved by the NRC in a letter dated December 8, 1981. However, since the NUREG-1801 XI.M6 program description does not explicitly mention blind flanging as a mitigation option, blocking the line with a blind flange instead of a cap can be viewed as an exception to NUREG-1801. Accordingly, the following changes are made to the LRA:

In LRA Appendix A, Section 18.1.8, BWR Control Rod Drive Return Line Nozzle Program, on page A-6, the last sentence is revised to read:

> This program is consistent with the ten elements of NUREG-1801 XI.M6 with two exceptions. The method for blocking the return line uses a blind flange instead of cutting and capping the line. The nozzle inspection frequency is based on ASME Code Section XI instead of NUREG-0619.

In LRA Table 3.1.2-1, Summary of Aging Management Review Results Nuclear Boiler, on page 3.1-43, in line item Nozzle - control rod drive return line with an Environment of Reactor coolant (internal) and an Aging Effect Requiring Management of Cracking, Note A is changed to Note B.

In LRA Table 3.3.2-7, Summary of Aging Management Review Results Control Rod Drive System, on page 3.3-113, in line item Pipe Class 1, pipe fittings, tubing with an environment of Reactor coolant (internal) and an Aging Effect Requiring Management of Cracking, Note C is changed to Note D.

In LRA Table B.2.2-1, Aging Management Program Correlation, on page B-8, the NUREG-1801 Comparison entry for line item XI.M6 - BWR Control Rod Drive Return Line Nozzle is changed to "Consistent with NUREG-1801 with two exceptions."

In LRA Section B.3.8, BWR Control Rod Drive Return Line Nozzle Program, on page B-22, Section B.3.8.2 is revised to read as follows:

> This program is consistent with six of the ten elements of NUREG-1801 XI.M6. Two exceptions are taken that affect Preventive Actions, Parameters Monitored or Inspected, Detection of Aging Effects, and Monitoring and Trending of NUREG-1801 XI.M6.

In LRA Section B.3.8, BWR Control Rod Drive Return Line Nozzle Program, on page B-22, Section B.3.8.3 is revised to read as follows:

> The DAEC program takes two exceptions to the guidance as stated in NUREG-1801 XI.M6.
>
> - DAEC takes exception to the NUREG-1801 description of "cutting and capping the CRDRL Nozzle without rerouting" as a mitigation option specified in NUREG-1801 XI.M6 Element 2, Preventive Actions. DAEC proposed a schedule and modifications to meet the requirements of NUREG-0619 in letters to the NRC dated February 4, 1981, and October 26, 1981. The letters described the modification planned to stop CRD flow by using a blind flange in lieu of a cut and cap method. The NRC approved this approach in a letter dated December 8, 1981. The approach taken is a fully acceptable alternative that is equivalent to cutting and capping the line.
>
> - DAEC takes exception to the NUREG-1801 description of the inspection schedule for the CRDRL nozzle based on NUREG-0619 as specified in NUREG-1801 XI.M6 Elements 3, Parameters Monitored/Inspected; 4, Detection of Aging Effects; and 5, Monitoring and Trending. NUREG-0619 specifies an inspection frequency of each refueling outage. The DAEC inspection frequency is based on ASME Code requirements implemented under 10 CFR 50.55a. The inspection requirements in the DAEC program provide a fully acceptable schedule of inspections commensurate with the NRC endorsed requirements of ASME Code Section XI.

RAI B.3.8-02

Background

GALL AMP XI.M6, BWR Control Rod Drive Return Line Nozzle, in the "Parameters Monitored or Inspected" program element, states that the AMP monitors the effects of cracking on intended function or the CRDRL nozzles by detecting and sizing cracks by in service inspection (ISI) in accordance with Table IWB 2500-1 and NUREG-0619. Program element "Detection of Aging Effects" states that the extent and schedule of inspection, as delineated in NUREG-0619, assures detection of cracks before the loss of intended function of the CRDRL nozzles. Program element "Monitoring and Trending" states that the inspection schedule of NUREG-0619 provides timely detection of cracks. NUREG-0619, Section 8.2(3)(b) states that during each refueling outage, that portion of the CRDRL containing stagnant water must be inspected in accordance with the recommendations in NUREG-0313, and that requirement this does not apply if the piping containing stagnant water is fabricated from carbon steel.

Issue

DAEC's Augmented Inspection Administrative Document, Section 5.4, states that the stainless steel portion of the control rod drive piping containing stagnant flow currently is examined every third refueling outage.

Request

Justify that examination every third refueling outage is adequate, and explain why this examination schedule is not identified as an exception to the recommendations in GALL AMP XI.M6, program elements "Parameters Monitored or Inspected," "Detection of Aging Effects," and "Monitoring and Trending."

DAEC Response to RAI B.3.8-02

As discussed in the response to RAI B.3.8-01, the LRA has been revised to add an exception to the DAEC BWR Control Rod Drive Return Line Nozzle Program to reflect the fact that the inspection frequency is based on ASME Code Section XI rather than NUREG-0619 as specified in NUREG-1801 XI.M6. The exception affects program elements 3, Parameters Monitored/Inspected; 4, Detection of Aging Effects; and 5, Monitoring and Trending.

As currently implemented at DAEC, the Control Rod Drive return line piping containing stagnant water is required to be ultrasonically examined in accordance with the following criteria:

1) Every reactor refueling outage.

2) If (1) above finds the welds free of unacceptable indications for three successive examinations, the examination frequency may be extended to each 36-month period (plus or minus by as much as 12 months) coinciding with a refueling outage. This is defined as every other outage.

3) If (2) above finds the welds free of unacceptable indications for three successive examinations, the frequency of examination may revert to 80-month periods (two-thirds the time prescribed in ASME Code Section XI). This is defined as every third refueling outage.

These inspection frequency criteria are conservative when compared to ASME Code Section XI requirements. Since the actual frequency is directly determined by plant specific inspection results, this approach provides an acceptable frequency to manage the Control Rod Drive return line piping and nozzle.

RAI B.3.10-1

Background

In DAEC LRA Section B3.10, the applicant states that the monitoring and control of reactor coolant water chemistry is in accordance with applicable BWRVIP reports, which are implemented by the DAEC water chemistry program. Furthermore, Section 2.0 of the DAEC Program Basis document for BWR penetrations (LRAP-M008) states that water chemistry is controlled per the EPRI guidelines of BWRVIP-130 BWR water chemistry guidelines – 2004 revision.

Issue

Program XI.M8 for BWR penetrations of the GALL report states that the monitoring and control of reactor coolant water chemistry is made in accordance with the guidelines of BWRVIP-29. The applicant states in Section 2.0 of LRAP-M008 that this is not considered an exception relative to the NUREG-1801 program description of the XI.M2 program. However, the staff considers this is an exception to the GALL XI.M8 program.

This issue also affects Element 2 (preventive actions) of this program. Moreover, in the BWRVIP administrative document, the applicant states that the DAEC implements the water chemistry guidelines per plant chemistry procedure (PCP) 1.9. The applicant referenced another procedure (PCP 1.16) in LRAP-M008.

Request

1. Clarify the BWRVIP used for water chemistry guidelines and justify acceptability if BWRVIP-29 is not used.
2. Clarify which PCP is used to implement the water chemistry guidelines.

DAEC Response to RAI B.3.10-1

Part 1

The NUREG 1801, XI.M2 Water Chemistry, program description states, "The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions."

The program description in the DAEC Water Chemistry Program basis document states, "The NUREG 1801, Section XI.M2 for Water Chemistry states that the water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions. The next revision to this industry guidance was published as

BWRVIP-79, “BWR Water Chemistry Guidelines”, March 2000. The subsequent revision, BWRVIP-130, “BWR Water Chemistry Guidelines”, October 2004 is what DAEC uses as a basis for the plant water chemistry control.” It should also be noted that DAEC is in the process of updating to BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision. The use of either BWRVIP-130 or BWRVIP-190 water chemistry guidelines is fully consistent with NUREG-1801 XI.M2.

The NUREG 1801, XI.M8 BWR Penetrations, Element 2 states “Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, “Water Chemistry.” The water chemistry program for BWR penetrations is the same chemistry program applied to the entire Reactor Coolant system. The last sentence of XI.M8 Element 2 clearly defers to NUREG-1801 XI.M2 for the description, evaluation and technical basis of the BWR water chemistry program, and does not limit the water chemistry program as applied to penetrations to a different standard than found acceptable for the rest of the Reactor Coolant System. Therefore, the use of a BWRVIP water chemistry standard found acceptable in NUREG-1801 XI.M2, even if not explicitly listed by number in XI.M8, is not considered an exception.

<u>Part 2</u>

PCP 1.9, Water Chemistry Guidelines, is used to implement the water chemistry guidelines for the Reactor Coolant System. The BWR Penetrations program basis document should have referenced PCP-1.9 instead of PCP 1.16.

RAI B.3.10-2

Background

In Section 3.4 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that alternatives for categories B-F and B-J have been incorporated into the DAEC BWR penetrations program. These alternatives are based on a risk-informed methodology.

However, the alternatives are approved only for the current ten-year interval.

Issue

Element 4 of program XI.M8 for BWR penetrations of the GALL report states that the evaluation guidelines of BWRVIP-49-A and BWRVIP-27-A recommend that the inspection requirements currently in ASME Section XI continue to be followed.

Request

Clarify how the inspections described in BWRVIP-27-A and BWRVIP-49-A will be implemented during the period of extended operation and modify your application as necessary.

DAEC Response to RAI B.3.10-2

During the period of extended operation, the inspections described in BWRVIP-27-A and BWRVIP-49-A will be performed in accordance with these BWRVIP reports and Categories B-F and B-J of ASME Code requirements, unless approval has been received from the NRC for relief or use of an alternative in accordance with 10 CFR 50.55a.

RAI B.3.10-3

Background

In Section 3.4.2 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that further details for examination are described in DAEC AMP LRAP-M001, ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD.

Issue

The staff noted that LRAP-M001 document does not refer to the DAEC program basis document dedicated to BWR penetrations, LRAP-M008.

Request

Explain how the requirements of LRAP-M008 are taken into account in LRAP-M001.

DAEC Response to RAI B.3.10-3

In NUREG-1801 XI.M8 BWR Penetrations, the last sentence in element 4, Detection of Aging Effects, states, " Further Details for examination are described in Chapter XI.M1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD, of this report." This statement indicates that program XI.M01, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD is a companion program to XI.M8, BWR Penetrations. This is restated in the DAEC BWR Penetrations program basis document, in section 3.4.2, "DAEC Detection of Aging Effects" to acknowledge that DAEC recognizes the XI.M01 program as a companion program to the XI.M8 program.

The DAEC ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program basis document, in section 3.4.2 "DAEC Detection of Aging Effects", cross-references the DAEC BWR Penetrations program basis document where it states, "DAEC implements the requirements of applicable approved BWRVIPs. The BWRVIPs credited for aging management for license renewal are discussed in LRAP-M004 through LRAP-M009." The program basis document for the BWR Penetrations Program is LRAP-M008.

NUREG-1801 XI.M8 element 4 acknowledges that, "The evaluation guidelines of BWRVIP-49 and BWRVIP-27 recommend that the inspection requirements currently in ASME Section XI continue to be followed." There are no exceptions or augmented requirements related to BWR penetrations that need to be discussed in the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program. Therefore, a general reference to the BWR Penetrations program is sufficient.

RAI B.3.10-4

Background

In Section 3.4.2 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that the guidelines in BWRVIP-03 are also being followed.

Issue

The staff did not find any reference to this BWRVIP report in the implementing documents it reviewed.

Request

Explain how the guidance of this BWRVIP report for detection of aging effects is taken into account in your AMP for BWR penetrations.

DAEC Response to RAI B.3.10-4

TR-105696-R9 (BWRVIP-03) Revision 9: "BWR Vessel Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines", provides guidance on reactor vessel internal inspections. The DAEC BWRVIP Administrative Document provides the program requirements for implementing the Boiling Water Reactor Vessel Internals Project (BWRVIP) Documents. The document also covers individual components for which the inspection requirements have been identified by the BWRVIP Inspection and Evaluation Guidelines.

Attachment 2 to the DAEC BWRVIP Administrative Document identifies that the applicable inspection guideline is BWRVIP-03 for various reactor vessel internal components including instrument and standby liquid control penetrations. This is the mechanism that assures that the guidance of the BWRVIP report for detection of aging effects is taken into account in the DAEC aging management program for BWR penetrations.

RAI B.3.10-5

Background

In Section 3.6.2 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that the evaluation of crack growth is in accordance with article IWB-3000 of ASME XI with guidance from BWRVIP-14, BWRVIP-59 and BWRVIP-60.

Issue

The staff did not find any reference to these three BWRVIP reports in the implementing documents it reviewed.

Request

Explain how the guidance of these BWRVIP reports for acceptance criteria is taken into account in your AMP for BWR penetrations.

DAEC Response to RAI B.3.10-5

LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is hereby revised to incorporate the following new commitment:

Item No.	System, Component or Program	Commitment	Section	Schedule
42.	BWR Penetrations Program	The implementing document for the BWR Penetrations Program will be revised to specify that guidance in BWRVIP-14, -59 and -60 is to be considered in the evaluation of crack growth in stainless steel, nickel alloys and low-alloy steels, respectively, when flaws are identified and evaluation required.	18.1.10	Prior to the period of extended operation

RAI B.3.10-6

Background

In Section 3.10.2 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that DAEC operating experience demonstrates that the current Inservice and Augmented Inspection programs are effective in managing the aging effect of cracking in the BWR penetration nozzles.

Issue

The applicant based its statement especially on the finding of indications in welds not included in the BWR penetrations program.

Request

Explain how the operating experience deducted from these indications can be applied for the BWR penetrations program and identify any operating experience specific to the BWR penetration nozzles.

DAEC Response to RAI B.3.10-6

The intent of the referenced discussion was to show that the DAEC has a robust NDE program which is successful in identifying indications, in general. Inspections of specific welds and penetrations which are included in the BWR Penetrations Program have been performed. These inspections included ultrasonic, surface and visual examinations and showed acceptable results.

RAI B.3.10-7

Background

In Section 2.2 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that the DAEC BWR penetrations program is an existing program and is part of the ASME Section XI Inservice inspection program.

In Section 3.1.2 of LRAP-M008, the applicant does not provide a description of the welds concerned by the BWRVIP-27-A and BWRVIP-49-A and included in its BWR penetrations program.

In attachment 7.1 of LRAP-M008, the applicant provides a list of equipment taken into account in the BWR penetrations program with particular references.

Issue

The staff reviewed the implemented documents such as the BWRVIP and the inservice inspection administrative documents but could not find a clear description of the welds included in the BWR penetrations program for those addressed by BWRVIP-49-A. Moreover, the references for welds concerned by the BWRVIP-27-A do not correspond to those of attachment 7.1 of LRAP-M008.

Request

Clarify which welds addressed by BWRVIP-27-A and BWRVIP-49-A are included in the BWR penetrations program.

DAEC Response to RAI B.3.10-7

The welds that are included in the BWR Penetrations Program are the nozzle-to-safe end welds and nozzle-to-vessel welds for Nozzle N10 (Core differential Pressure and Standby Liquid Control Nozzle) and Nozzles N11A/B, N12A/B, and N16A/B (Instrumentation Nozzles).

The welds associated with the N10 nozzle are covered under the BWRVIP-27-A, "BWR Vessel and Internals Project BWR Standby Liquid Control/Core Plate ΔP Inspection and Flaw Evaluation Guidelines". These welds are included in the components that are identified in Attachment 7 to the aging management program basis document as 1T201-DP/SLC-NOZZLE and 1T201-DP/SLC-SAFEEND.

The welds associated with the N11A/B, N12A/B and N16A/B nozzles are covered under the BWRVIP-49-A, "BWR Vessel and Internals Project, Instrumentation Penetration Inspection and Flaw Evaluation Guidelines." These welds are included in the components that are identified in Attachment 7.1 to the aging management program basis document as 1T201-INST-SAFEEND and 1T201-INST-NOZZLE.

The LRA indicates that the Jet Pump Instrumentation nozzles (N8A & N8B) and the Reactor Vessel Drain Nozzle (N15) are being managed by the BWR Penetrations Program. This is incorrect, as they are actually managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program. Similarly, the Control Rod Drive safe ends are shown as being managed by the BWR Penetrations Program, but are actually being managed by the BWR Control Rod Drive Return Line Nozzle Program. Accordingly, the LRA is being revised to cite the correct programs, as follows:

In LRA Table 3.1-1, line item 3.1.1-40 on page 3.1-16, the last sentence of the Discussion entry is revised to read, "The jet pump instrument nozzle and the drain nozzle are managed by the ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program."

In LRA Table 3.1.2-1 on page 3.1-46, the line item for Nozzle - jet pump instrumentation with the Aging Effect Requiring Management of Cracking is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Nozzle - jet pump instrumentation	Pressure boundary	Carbon steel with stainless steel cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program Water Chemistry Program	IV.C1-4 (R-15)	3.1.1-20	C

In LRA Table 3.1.2-1 on page 3.1-55, the line item for Safe end - control rod drive with the Aging Effect Requiring Management of Cracking is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Safe end - control rod drive	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	BWR Control Rod Drive Return Line Nozzle Program	IV.A1-2 (R-66)	3.1.1-38	C

In LRA Table 3.1.2-1 on page 3.1-56, the line item for Safe end - core differential pressure and standby liquid control with the Aging Effect Requiring Management of Cracking is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Safe end - core differential pressure and standby liquid control	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	BWR Penetrations Program Water Chemistry Program	IV.A1-5 (R-69)	3.1.1-40	C

In LRA Table 3.1.2-1 on page 3.1-58, the line item for Safe end - jet pump instrumentation with the Aging Effect Requiring Management of Cracking is revised to appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 line Item	Table 3.X.1 item	Notes
Safe end - jet pump instrumentation	Pressure boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program Water Chemistry Program	IV.C1-4 (R-15)	3.1.1-20	C

RAI B.3.10-8

Background

In Attachment 7.1 of the DAEC Program Basis document for BWR penetrations (LRAP-M008), the applicant states that the aging effects for the components are SCC/IGA.

Issue

The components concerned by the BWR penetrations program are stainless steel and their environment is reactor coolant. Thus, the aging effect is IGSCC, not IGA.

Request

Discuss your plan to modify your basis document accordingly.

DAEC Response to RAI B.3.10-8

DAEC recognizes that there are different types of stress corrosion cracking (SCC). SCC can be categorized as either intergranular stress corrosion cracking (IGSCC) or transgranular stress corrosion cracking (TGSCC), depending upon the primary crack morphology. In addition, austenitic stainless steels exposed to a neutron fluence (>1 MeV) in excess of 1×10^{21} n/cm^2 may be susceptible to irradiation assisted stress corrosion cracking (IASCC).

Intergranular attack (IGA), also known as intergranular corrosion, is similar in some respects to SCC; however, it is distinguished from SCC in that stress is not necessary for it to proceed. Generally, materials and conditions that are susceptible to intergranular stress corrosion cracking will also be susceptible to IGA.

EPRI TR-1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4" in section 3.2.2 discusses stress corrosion cracking and is the source for the conclusions stated above. These "Mechanical Tools" were used as the basis for determining how aging effects for material and environment conditions should be addressed for license renewal.

For stainless steels and CASS materials, SCC and IGA are grouped together by the Mechanical Tools. They state that, in treated water systems, dissolved oxygen, sulfates, fluorides, and chlorides can provide the necessary environment for SCC or IGA to occur. Therefore, when cracking is discussed for these materials, it is just referred to as stress corrosion cracking, with the understanding that IGA could also occur.

When setting up the software program for license renewal to document the evaluation of material and environment conditions for aging effects, the selection "SCC/IGA" was provided to signify that cracking was an applicable aging effect. Attachment 7.1 of the program basis document just reflects the terminology that was used in the license renewal software program. Since the discussion in the License Renewal Application (LRA) is limited in most cases to discussing the aging effect of cracking, the question of which aging mechanism caused the aging effect of cracking is not usually germane to aging management. Regardless of which aging mechanism was identified that might initiate the cracking, the inspection techniques for identifying cracking are the same.

RAI B.3.11-1

Background

In its review of operating experience, the staff noted that CAP010488 was submitted on June 28, 1994 with the One Line Description of "V27-180 Reactor Cleanup." The Detailed Description section of CAP010488 stated that:

1. Verify CMARS are written & applicable weld are repaired during RFO13
2. Verify that the operations exams welds during class 1 leak test QDR 94007 conversion

Issue

The staff found a need to clarify how the corrective action was closed. As applicable, the staff also needs to clarify how effective the applicant's BWR Reactor Water Cleanup (RCWU) System Program has been in terms of detecting and managing the effects of SCC in the RWCU system.

Request

1. Clarify whether the weld repair is related with the occurrence of SCC in the RWCU system. Describe the location of the weld including the weld was located inboard or outboard of the second isolation valve.
2. If applicable, describe how the weld was repaired and clarify whether an additional SCC indication has been observed in the repaired weld.
3. Describe how effective the BWR Reactor Water Cleanup System Program has been in terms of detecting and managing the SCC in the RWCU system: Please, use the aforementioned and other available operating experience for the response as applicable.

DAEC Response to RAI B.3.11-1

Part 1
The conclusion of the failure analysis was that repeated welding at the same location due to the short length of the pipe nipple created sensitized material which had low resistance to IGSCC. With the high temperature, high pressure and reactor water, the environment was favorable to IGSCC. The leak was located outboard of the second isolation valve. The cause of the failure was most probably due to IGSCC.

Part 2
The leaking 3" long by ¾" type 304 stainless steel pipe nipple was removed and was replaced with a longer, type 304L stainless steel nipple so that the two welds are at least 4" apart. Since replacement, the longer type 304L stainless steel nipple has not failed.

Part 3

DAEC has implemented plant modifications to eliminate IGSCC susceptible material that is exposed to temperatures equal to or greater than 140°F, except for short pieces of vendor supplied pipe and welds between heat exchangers. The short pieces of non-resistant pipe are categorized as IGSCC Category Class D.

Accessible portions of the short pieces of non-resistant pipe between the heat exchangers were inspected and found to be free of IGSCC and SCC. After completing the pipe replacement, the hydrostatic test revealed leakage in the inner radius of a bend in the piping which had been difficult to inspect due to contour and surface condition causing non-optimum contact of the transducer. Analysis showed this indication was not related to IGSCC. The defective pipe was replaced and tested satisfactorily, and additional RWCU pipes of the same configuration were reexamined to assure no other similar defects existed. No additional cracking has been observed.

RAI B.3.11-2

Background

In LRA Section B.3.11, the applicant stated that the BWR Reactor Water Cleanup Program is an existing program with one exception that the applicant's program implements the requirements of NRC Generic Letter (GL) 88-01 as modified by BWRVIP-75 and BWRVIP-75 specifies an inspection frequency that differs from the requirements given in GL 88-01. The applicant also stated that the program includes the RWCU [reactor water cleanup system] stainless steel pipe welds between the reactor and the second containment isolation valve and inspections of the appropriate welds outboard of the second isolation valve.

The staff also noted that the following reference indicates that the applicant's RWCU system had 81 non-safety-related welds under IGSCC Category G: In accordance with GL 88-01, Category G welds are the welds that are made of non-resistant material and not inspected.

> Reference: U.S. NRC Letter to the Iowa Electric Light and Power Company, NRC Generic Letter 88-01 - "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping" (TAC NOS. 69008 and 69123), May 31, 1990, including Enclosure: See pages 7 and 8 of Enclosure

The onsite program document suggested that some of the outboard welds were replaced with SCC-resistant material.

The staff also noted that GALL AMP XI.M25 recommends inspection Schedule A, B or C depending on the applicant's satisfactions of the NRC screening criteria for the RWCU piping outboard of the second isolation valve. The screening criteria include:

(a) Satisfactory completion of all actions requested in NRC GL 89-10
(b) No detection of IGSCC in RWCU welds inboard of the second isolation valves (ongoing inspection in accordance with GL 88-01)
(c) No detection of IGSCC in RWCU welds outboard of the second isolation valves after inspecting a minimum of 10% of the susceptible piping

In relation with the screening criteria, GALL AMP XI.M25 recommends the following inspection schedules:

- Schedule A: No inspection is required for plants that meet all the three criteria set forth above or if they meet only criterion (a) and piping is made of material that is resistant to IGSCC.
- Schedule B: For plants that meet only criterion (a): Inspect at least 2% of the welds or two welds every refueling outage, whichever sample is larger

- Schedule C: For plants that do not meet criterion (a): Inspect at least 10% of the welds every refueling outage

Issue

The LRA or on-site documentation does not clearly describe what inspections are performed on the piping outboard of the second isolation valve in the applicant's program in terms of inspection extent and schedule.

Request

1. Clarify what inspections are performed on the outboard piping in terms of inspection extent and schedule.
2. Clarify whether all IGSCC Category G welds that were described in the foregoing reference were replaced with materials resistant to IGSCC.
3. Describe which screening criteria described in GALL AMP XI.M25 are met by the applicant. Provide the technical basis of the applicant's evaluation.
4. Clarify which Schedule of the GALL AMP XI.M25 (Schedule A, B or C) is relevant for the RWCU piping welds outboard of the second isolation valve.
5. Confirm whether the determination of the inspection schedule is consistent with the operating experience addressed in RAI 3.11-1.

DAEC Response to RAI B.3.11-2

Part 1

DAEC has implemented plant modifications to eliminate IGSCC susceptible material that is exposed to temperatures equal to or greater than 140°F except for short pieces of vendor supplied pipe and welds between heat exchangers. The short pieces of non-resistant pipe are categorized as IGSCC Category Class D. Inspections of RWCU piping welds outboard of the second isolation valve that are made with IGSCC resistant materials are not required and are not performed. The DAEC Chemistry BWRVIP Program manages the effect of stress corrosion (SCC) and IGSCC on all piping in the RWCU system.

Part 2

Piping and welds located outside of the second isolation valve and exposed to temperatures greater than 140°F have been replaced with IGSCC resistant material. All category G welds were replaced as part of this modification.

Part 3

The screening criteria stated in NUREG 1801 are as follows:

Based on the NRC letter (September 15, 1995) on the screening criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 to monitor SCC or IGSCC and its effects on the intended function of austenitic SS piping. The screening criteria include:

a. Satisfactory completion of all actions requested in NRC GL 89-10,

b. No detection of IGSCC in RWCU welds inboard of the second isolation valves (ongoing inspection in accordance with the guidance in NRC GL 88-01), and

c. No detection of IGSCC in RWCU welds outboard of the second isolation valves after inspecting a minimum of 10% of the susceptible piping.

No IGSCC inspection is recommended for plants that meet all the above three criteria or that meet criterion "a," and piping is made of material that is resistant to IGSCC.

DAEC has completed all actions required by GL 89-10. The acceptance of the DAEC actions to meet GL 89-10 is documented in the NRC letter dated January 25, 1996. Accordingly, no IGSCC inspection is required.

<u>Part 4</u>

DAEC is classified as a Schedule A plant as defined in NUREG 1801.

<u>Part 5</u>

NUREG 1801 does not recommend inspections for plants that have satisfactorily completed all actions requested in NRC GL 89-10 and piping is made of material that is resistant to IGSCC.

DAEC has met both of these requirements and does not inspect the piping and welds which are located outside of the second isolation valve and exposed to temperatures greater than 140°F. The description of the weld anomaly noted in RAI 3.11-1 involved repeated welding in the same area and the piping was replaced with a longer nipple to preclude this fabrication problem.

RAI B.3.11-3

Background

In LRA Section B.3.11, the applicant stated that the BWR Reactor Water Cleanup Program is an existing program with one exception that the applicant's program implements the requirements of NRC Generic Letter (GL) 88-01 as modified by BWRVIP-75 and BWRVIP-75 specifies an inspection frequency that differs from the requirements given in GL 88-01. The applicant also stated that the program includes the RWCU [reactor water cleanup system] stainless steel pipe welds between the reactor and the second containment isolation valve and inspections of the appropriate welds outboard of the second isolation valve.

In contrast, LRA Table 3.3.2-24 for the aging management review of the RWCU components indicates that Class 1 components such as flow element, pipe fittings and tubing, and valve in the system credit the BWR Stress Corrosion Cracking Program to manage the effects of stress corrosion cracking.

Issue

The staff noted that the Program Description section of GALL AMP XI.M25, "BWR Reactor Water Cleanup System," stated that based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC Generic Letter (GL) 88-01. In addition, the staff noted that the program element, scope of program, of GALL AMP XI.M25 describes the screening criteria for the determination of the inspection schedule for the RWCU piping outboard of the second isolation valve. In turn, the detailed inspection schedules for the RWCU welds outboard of the second isolation valve are described in the program element, parameter monitored/inspected.

Request

1. Clarify what portions of RWCU piping and piping welds are included in the program scope of the BWR Reactor Water Cleanup System Program to manage the effects of SCC or IGSCC. If applicable, describe what other programs are credited to manage the effects of SCC in the RWCU piping inboard of the second isolation valves.
2. In consideration of the foregoing evaluation related to the program scope and the inspection schedules for the RWCU outboard piping described in GALL AMP XI.M25, clarify whether the exception that the applicant claimed to GL 88-01 for the inspection frequency modified by BWRVIP-75 is still applicable to the BWR Reactor Water Cleanup Program.
3. If applicable, describe how the UFSAR supplement will be revised in accordance with the foregoing evaluation regarding the program exception.

DAEC Response to RAI B.3.11-3

Part 1

DAEC has implemented plant modifications to eliminate IGSCC susceptible material that is exposed to temperatures equal to or greater than 140°F except for short pieces of vendor supplied pipe and welds between heat exchangers. The short pieces of non-resistant pipe are categorized as IGSCC Category Class D. The DAEC Chemistry BWRVIP Program manages the effect of stress corrosion (SCC) and IGSCC on all piping in the RWCU system.

The portion of the RWCU piping extending from the reactor coolant recirculation system up to and including the containment isolation valves are managed consistent with NUREG-1801 Table IV.C1. The programs credited to manage the effects of SCC are the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the Water Chemistry Program, the BWR Stress Corrosion Cracking Program, and the ASME Code Class 1 Small-Bore Piping Inspection Program.

Part 2

DAEC does not perform Augmented ISI inspections on piping outside of the second isolation valve to the inspection frequency as required by GL 88-01 and follows the guidance in BWRVIP-75. Therefore, as noted in LRA Section B.3.11, this is considered an exception to NUREG-1801 XI.M25.

Part 3

DAEC has concluded that the UFSAR description of the program in LRA Appendix A, Section 18.1.11, is correct as written. However, the description of the BWR Reactor Water Cleanup System Program description in LRA Section B.3.11 is being revised to incorporate clarifications, as follows:

In LRA Section B.3.11.1, Program Description, on page B-27, the second sentence, "This program ... isolation valve," is deleted in its entirety.

LRA Section B.3.11.5, Operating Experience, on page B-28, is revised in its entirety to read as follows:

B.3.11.5 OPERATING EXPERIENCE

The DAEC Reactor Water Cleanup System Program has been effective in managing the aging effects of cracking due to SCC or IGSCC in the RWCU piping. The program incorporates both industry and plant-specific operating experience to provide added assurance that the aging effects are managed such that these components will continue to perform their intended function(s) throughout the period of extended operation.

DAEC has implemented plant modifications to eliminate the IGSCC susceptible material that is exposed to temperatures equal to or greater than 140°F except for short pieces of vendor supplied pipe and welds between heat exchangers. The short pieces of non-resistant pipe are categorized as IGSCC Category Class D.

RAI B.3.12-1

Background

In Section 3.6.2 of DAEC Program Basis document for the BWR SCC (LRAP-M0007), the applicant states that the DAEC BWR SCC program will evaluate any indication detected in accordance with IWB-3600 of the applicable Edition/Addenda of ASME Section XI, and the applicable BWRVIPs to determine acceptance and/or disposition.

Issue

The staff notes that Section 3.6.2 does not specify which applicable BWRVIPs will be implemented for this program per NUREG-1801 X1.M7 Acceptance Criteria.

Request

State the applicable BWRVIPs that will be implemented as guidance to be consistent with NUREG-1801 X1.M7 Acceptance Criteria.

DAEC Response to RAI B.3.12-1

NUREG 1801, Revision 1, XI.M7 element Acceptance Criteria, states that applicable and approved BWRVIP-14, BWRVIP-59, BWRVIP-60, and BWRVIP-62 documents provide guidelines for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 guidelines for BWR vessel and internals induction heating stress improvement effectiveness on crack growth in operating plants.

BWRVIP-14, -59 and -60 are the applicable BWRVIP reports referred to in Section 3.6.2 of the DAEC Program Basis Document for evaluation of crack growth, if flaws are identified and evaluation required.

BWRVIP-62 is the BWRVIP Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection. It is not expected that this document would be used specifically for flaw evaluation.

DAEC has no current plans to use induction heating stress improvement for the vessel and internals. If such stress improvement were needed in the future, the BWRVIP-61 guidelines would be considered.

RAI B.3.12-2

Background

The DAEC Program Basis document for the BWR SCC (LRAP-M0004) uses PCP 1.16, "Plant Chemistry Procedures 3200 Manual, Chemistry BWRVIP Program," as the implementing document to apply mitigation in accordance to the DEAC Water Chemistry Program. The BWR SCC program also implements the "Program Engineering ASME Section XI Administrative manual, BWRVIP Administrative Document," Revision 14.

Issue

The staff notes PCP 1.16 references BWRVIP-130 for implementing recommendations, and the BWRVIP Administrative Document Section 5.15 references BWRVIP-190 as the water chemistry guideline.

Request

State the correct BWRVIP for the water chemistry guidelines applicable to the BWR SCC program that will be implemented to be consistent with NUREG-1801 X1.M7, Scope.

DAEC Response to RAI B.3.12-2

The BWR Stress Corrosion Cracking Program basis document at DAEC is LRAP-M007, not LRAP-M004 as cited in "Background."

NUREG-1801 program XI.M7, BWR Stress Corrosion Cracking, element 2 Preventive Actions, states, "The program description, and evaluation and technical basis of monitoring and maintaining reactor water chemistry are addressed through implementation of Section XI.M2, "Water Chemistry."

The NUREG 1801 program XI.M2 Water Chemistry, Program Description states, "The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions."

The program basis document for the DAEC Water Chemistry Program states, "The NUREG 1801 Section XI.M2 for Water Chemistry states that the water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions. The next revision to this industry guidance was published as

BWRVIP-79, "BWR Water Chemistry Guidelines", March 2000. The subsequent revision, BWRVIP-130, "BWR Water Chemistry Guidelines", October 2004 is what DAEC uses as a basis for the plant water chemistry control." It should be noted that DAEC is in the process of incorporating BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision, into affected chemistry procedures.

For BWR Stress Corrosion Cracking, BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision, is now the applicable industry standard used to implement the water chemistry guidelines.

RAI B.3.13-1

Background

In Section 3.5.2 of DAEC Program Basis document for the BWR Vessel ID Attachment welds (LRAP-M0004), the applicant states that the BWR Vessel ID Attachment welds program will follow the requirements of ASME Section XI, IWB, and the guidelines of BWRVIP-48-A.

Issue

The staff notes that Section 3.5.2 does not specify how indications will be monitored or trended to ensure sample expansion and/or inspections are performed for meeting the stated requirements and guidelines.

Request

Clarify how any discovered indications will be monitored or trended to ensure sample expansion and/or inspections are performed for meeting the stated requirements and guidelines, and be consistent with NUREG-1801 X1.M4 Monitoring and Trending.

DAEC Response to RAI B.3.13-1

For monitoring and trending, NUREG-1801 program XI.M7, Vessel ID Attachment Welds, element 5, Monitoring and Trending, describes monitoring and trending as, "Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-48 guidelines provide timely detection of cracks. If flaws are detected, the scope of examination is expanded."

BWRVIP-48-A states that, for indications which are detected during the EVT-1 inspections, ultrasonic inspections should be performed to determine if the indication has propagated into the reactor vessel base material. For any flaws which are found to have propagated into the vessel base material, an evaluation should be performed in accordance with the requirements of ASME Section XI.

If one or more flaws are found during either the baseline inspection or reinspection, all of the remaining locations of the same type (e.g., core spray bracket attachment welds) should be inspected during the same outage unless the licensee can correlate the flaw to a specific event which would not affect other locations.

This is consistent with the description of monitoring and trending described in NUREG-1801. In addition, for any indication discovered during the inspection, a corrective action would be initiated to monitor and trend the actions taken.

RAI B.3.13-2

Background

In Section 3.4.2 of DAEC Program Basis document for the BWR Vessel ID Attachment welds (LRAP-M0004), the applicant states that the BWR Vessel ID Attachment welds program will follow the guidelines of BWRVIP-48-A. NUREG-1801 X1.M4 Detection of Aging Effects, permits BWRVIP-48 as an acceptable guidance to follow. For nondestructive examination (NDE), BWRVIP-03 is mentioned as appropriate.

Issue

The staff notes that Section 3.4.2 does not specify if BWRVIP-03 will be implemented for appropriate NDE techniques per NUREG-1801 X1.M7 Detection of Aging Effects.

Request

State if the guidelines for appropriate NDE techniques per BWRVIP-03 will be followed.

DAEC Response to RAI B.3.13-2

Inspection guidelines of BWRVIP-03 will be followed.

RAI B.3.13-3

Background

In Section 3.6.2 of DAEC Program Basis document for the BWR Vessel ID Attachment welds (LRAP-M0004), the applicant states that the BWR Vessel ID Attachment welds program will evaluate any indication detected in accordance with ASME Section XI and applicable approved BWRVIPs.

Issue

The staff notes that Section 3.6.2 does not specify which specific applicable BWRVIPs will be implemented for this program per NUREG-1801 X1.M4 Acceptance Criteria.

Request

State the applicable BWRVIPs that will be implemented as guidance to be consistent with NUREG-1801 X1.M4 Acceptance Criteria.

DAEC Response to RAI B.3.13-3

In NUREG 1801, Revision 1, XI.M4, element Acceptance Criteria states that any indication detected is evaluated in accordance with ASME Section XI or the staff-approved BWRVIP-48 guidelines. Applicable and approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively.

BWRVIP-14, -59 and -60 are the applicable BWRVIP reports referred to in Section 3.6.2 of the DAEC Program Basis Document for evaluation of crack growth if flaws are identified and evaluation is required.

RAI B.3.13-4

Background

The DAEC Program Basis document for the BWR Vessel ID Attachment Welds (LRAP-M0004) uses PCP 1.16, "Plant Chemistry Procedures 3200 Manual, Chemistry BWRVIP Program," as the implementing document to apply mitigation in accordance to the DEAC Water Chemistry Program. The BWR Vessel ID Attachment Welds program also implements the "Program Engineering ASME Section XI Administrative manual, BWRVIP Administrative Document," Revision 14.

Issue

The staff notes PCP 1.16 references BWRVIP-130 for implementing recommendations, and the BWRVIP Administrative Document Section 5.15 references BWRVIP-190 as the water chemistry guideline.

Request

State the correct BWRVIP for the water chemistry guidelines applicable to the BWR Vessel ID Attachment Welds program that will be implemented to be consistent with NUREG-1801 X1.M4, Scope.

DAEC Response to RAI B.3.13-4

NUREG 1801, XI.M4 BWR Vessel ID Attachment Welds, Element 2 states, "The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Section XI.M2, "Water Chemistry."

NUREG 1801, XI.M2 Water Chemistry, Program Description states, "The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions."

The program basis document for the Water Chemistry Program states "The NUREG 1801 Section XI.M2 for Water Chemistry states that the water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions. The next revision to this industry guidance was published as BWRVIP-79, "BWR Water Chemistry Guidelines", March 2000. The subsequent revision, BWRVIP-130, "BWR Water Chemistry Guidelines", October 2004 is what DAEC uses as a basis for the plant water chemistry control." It should be noted that DAEC is in the process of incorporating BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision.

For the BWR Vessel ID Attachment Welds Program, BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision, is now the applicable industry standard used to implement the water chemistry guidelines. To reflect this change, the LRA is being revised to remove an outdated reference to BWRVIP-130 as follows:

In LRA Section B.3.13, BWR Vessel ID Attachment Welds Program, in Section B.3.13.1 Program Description, the third sentence of the third paragraph "The DAEC Water Chemistry program implements the guidelines of BWRVIP-130 ... with NUREG-1801, XI.M2." is deleted in its entirety.

RAI B.3.14-1

Background

In DAEC LRA 4.3.2, Reactor Vessels Internal Fatigue, states that the shroud support is considered part of the vessel. Table 4.3.2 presents fatigue usage factor for the shroud support. Section 7, Attachment 7.1, "List of Equipment with Aging Management Program Scope," of DAEC Program Basis document for the BWR Vessel Internals (LRAP-M0009), identifies the shroud support covered under this program.

Issue

The staff notes that Attachment 7.1 of LRAP-M0009 does not identify fatigue as an aging effect considered for the shroud support.

Request

Explain how the BWR Vessel Internals program is addressing this possible aging effect, or why it is not necessary to evaluate it under the BWR Vessel Internals program.

DAEC Response to RAI B.3.14-1

The BWR Vessel Internals Program manages the aging effects due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) of the Shroud Support.

Fatigue for the Shroud Support is evaluated with the reactor vessel as a Time Limited Aging Analysis and managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

RAI B.3.14-2

Background

The DAEC Program Basis document for the BWR Vessel Internals (LRAP-M0009) uses PCP 1.16, "Plant Chemistry Procedures 3200 Manual, Chemistry BWRVIP Program," as the implementing document to apply mitigation in accordance to the DEAC Water Chemistry Program. The BWR Vessel Internals program also implements the "Program Engineering ASME Section XI Administrative manual, BWRVIP Administrative Document," Revision 14.

Issue

The staff notes PCP 1.16 references BWRVIP-130 for implementing recommendations, and the BWRVIP Administrative Document Section 5.15 references BWRVIP-190 as the water chemistry guideline.

Request

State the correct BWRVIP for the water chemistry guidelines applicable to the BWR Vessel Internals program that will be implemented to be consistent with NUREG-1801 X1.M9, Scope.

DAEC Response to RAI B.3.14-2

NUREG 1801, XI.M9 BWR Vessel Internals, Element 2 states "The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

NUREG 1801, XI.M2 Water Chemistry, Program Description states "The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions."

The program basis document for the Water Chemistry Program states, "The NUREG 1801 Section XI.M2 for Water Chemistry states that the water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines such as the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515) or later revisions. The next revision to this industry guidance was published as BWRVIP-79, "BWR Water Chemistry Guidelines", March 2000. The subsequent revision, BWRVIP-130, "BWR Water Chemistry Guidelines", October 2004 is what DAEC uses as a basis for the plant water chemistry control." It should be noted that DAEC is in the process of incorporating BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision.

For the BWR Vessel Internals Program, BWRVIP-190, BWR Water Chemistry Guidelines, 2008 Revision, is now the applicable industry standard used to implement the water chemistry guidelines.

RAI B.3.15-1

Background

The evaluation and technical basis described in the Closed-Cycle Cooling Water System Program in NUREG-1801, Rev. 1, Section XI.M21 indicates that the closed cycle cooling water system may rely upon the EPRI TR-107396 document to manage cooling water chemistry to minimize exposure to aggressive environments and ensure correct application of corrosion inhibitors.

Issue

The DAEC LRA, Appendix B, Section B.3.15 indicates that the applicant's Closed-Cycle Cooling Water System Program is consistent with NUREG-1801, Rev. 1 Section XI.M21 and does not take any exceptions. In addition, the applicant indicates that it maintains the closed-cycle cooling water system corrosion chemistry within specified limits of EPRI TR-107396. This EPRI document is citied throughout the Closed-Cycle Cooling Water System basis document, LRAP-M021. However, the reference for the EPRI TR-107396 shown in the basis document is actually EPRI TR-1007820, which is the revision to EPRI TR-107396. It is unclear to the staff, which EPRI document the applicant plans to use to monitor the closed-cycle cooling water system.

Request

Provide additional information depending on whether the applicant plans to use the EPRI TR-107396 or the EPRI TR-1007820 document to manage the closed-cycle cooling water systems. If the applicant plans on using the EPRI TR-107396, provide additional information how the use of the initial version of the EPRI Closed Cooling Water Chemistry Guideline captures the most recent operating experience. If the applicant plans on using the EPRI TR-1007820, indicate if there are any changes that the applicant plans on making to the operating procedures to incorporate the new operational experience captured in the latest version of the EPRI Closed Cooling Water Chemistry Guideline document.

DAEC Response to RAI B.3.15-1

DAEC will utilize EPRI TR-1007820 as the applicable closed-cycle cooling water standard. To reflect this standard, applicable sections of the LRA are being changed to reflect the correct program reference to EPRI TR-1007820 and to indicate that an exception is taken to NUREG-1801 for use of this standard, as follows:

In LRA Appendix A, Section 18.1.15, Closed Cooling Water System Program, is revised in its entirety to read as follows:

> The Closed Cooling Water System Program relies on implementation of the guidance provided in EPRI TR-1007820 to ensure that the closed cycle cooling water system functions and components serviced by the system are not

compromised by aging. The program includes control of chemistry parameters to minimize corrosion and stress corrosion cracking. DAEC performs testing and inspections of the CCCW systems, components to ensure the performance is maintained and the intended functions are not compromised by aging.

This program is consistent with the ten elements of NUREG-1801 XI.M21 with the exception that the program standard is EPRI TR-1007820 rather than EPRI TR-107396.

In LRA Table B.2.2-1 on page B-9, the NUREG-1801 Comparison entry for program XI.M21 is revised to state, "Consistent with NUREG-1801 with one exception".

In LRA Section B.3.15, Closed-Cycle Cooling Water System Program, is revised in its entirety to read as follows:

B.3.15 CLOSED-CYCLE COOLING WATER SYSTEM PROGRAM

B.3.15.1 PROGRAM DESCRIPTION

The DAEC Closed-Cycle Cooling Water (CCCW) System Program is an existing program. The program manages the aging effects of corrosion, fouling, heat transfer degradation and Stress Corrosion Cracking (SCC).

The scope of the program includes Reactor Building Closed Cooling System (RBCCW), Control Building Chiller CCW System, Offgas Condenser CCW System, and Stand By Diesel Generator (SBDG) Jacket Coolers.

The CCCW program is managed through DAEC procedures and guidance documents, and is based on parameters and guidance delineated in EPRI TR-1007820, “Closed Cooling Water Chemistry Guideline”.

This program relies on the implementation of guidance provided in EPRI TR-1007820 to ensure that the CCCW system functions and components serviced by CCCW are not compromised by aging. The program includes control of chemistry parameters to minimize corrosion and stress corrosion cracking (SCC). DAEC maintains CCCW system corrosion inhibitors within the specified limits of EPRI TR-1007820 to minimize corrosion and SCC. DAEC performs testing and inspections of the CCCW systems, components to ensure the performance is maintained and the intended functions are not compromised by aging.

DAEC implements guidance to control the chemistry parameters in closed-cycle cooling water systems. The chemistry parameters are recorded, monitored and trended on a prescribed frequency.

B.3.15.2 NUREG-1801 CONSISTENCY

This program is consistent with seven of the ten elements of NUREG-1801 XI.M21. One exception is taken that affects "Preventive Action," "Parameters Monitored and inspected," and "Monitoring and Trending." of NUREG 1801 XI.M21.

B.3.15.3 EXCEPTIONS TO NUREG-1801

The DAEC program takes one exception to the guidance as stated in NUREG-1801 XI.M21. This exception affects the following elements of NUREG-1801 XI.M21.

- Preventive Actions

  NUREG-1801 states: The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC.

  The Duane Arnold Energy Center Closed Cooling Water program is based on guidance from EPRI TR-1007820 and good industry practices.

- Parameters Monitored or inspected

  NUREG-1801 states: The aging management program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component condition.

  DAEC monitors the effects of corrosion and SCC by testing and inspecting the chemistry parameters in accordance with guidance from EPRI TR-1007820.

- Monitoring and Trending

  NUREG-1801 states: In accordance with EPRI TR-107396, internal visual inspections and performance/functional tests are to be performed periodically to demonstrate system operability and confirm the effectiveness of the program.

  DAEC samples, monitors and trends the CCCW water chemistry in accordance with EPRI TR-1007820, good industry practices and plant operating conditions and established trends.

B.3.15.4 ENHANCEMENTS TO DUANE ARNOLD PROGRAM

The program does not require any enhancements to be consistent with the ten elements of NUREG-1801 XI.M21.

B.3.15.5 OPERATING EXPERIENCE

The DAEC Closed-Cycle Cooling Water System Program has been effective in managing the aging effects of corrosion, fouling and heat transfer degradation and stress corrosion cracking (SCC). The program incorporates both industry and plant specific operating experience to provide added assurance that the aging effects are managed such that these systems will continue to perform their intended function(s) throughout the period of extended operation.

A review of plant operating experience related to the Closed Cycle Cooling Water Program shows that the program has been successful at identifying chemistry parameters that were out of acceptable tolerances. These issues were documented and addressed using the DAEC Corrective Action Program.

DAEC self assessments identified areas for program enhancements within the chemistry management of the CCCW systems. DAEC used the corrective action program to document and conclude the actions required to ensure the CCCW systems are managed in compliance with good industry practices and the EPRI guidance document TR-1007820.

B.3.15.6 CONCLUSION

The Closed-Cycle Cooling Water System Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

As a result of the program exception, the Notes entries for all 3.x.2 table line items which cite the Closed-Cycle Cooling Water Program are changed either from A to B or from C to D, as applicable. The affected 3.x.2 tables are as follows:

- Table 3.3.2-6 on pages 3.3-90, 3.3-93, 3.3-95, 3.3-96, 3.3-97, 3.3-98, 3.3-100, 3.3-101, 3.3-103, 3.3-104, and 3.3-106
- Table 3.3.2-14 on page 3.3-156
- Table 3.3.2-19 on page 3.3-176
- Table 3.3.2-22 on pages 3.3-188, 3.3-190, 3.3-191, and 3.3-192
- Table 3.3.2-24 on page 3.3-203
- Table 3.3.2-29 on pages 3.3-228, 3.3-233, 3.3-234, 3.3-235, 3.3-238, 3.3-239, 3.3-240, 3.3-242, 3.3-244, 3.3-246, 3.3-247, and 3.3-248

RAI B.3.15-2

Background

The preventive actions, described in the Closed-Cycle Cooling Water System Program in NUREG-1801, Rev. 1, Section XI.M21 indicates that the guidance in EPRI TR-107396 may be used to monitor closed cooling water chemistry to minimize exposure to aggressive environments.

Issue

The DAEC LRA, Appendix B, Section B.3.15 indicates that the applicant's Closed-Cycle Cooling Water System Program is consistent with the NUREG-1801, Rev. 1 Section XI.M21 and does not take any exceptions. In addition, the applicant indicates that its prevention and monitoring practices are based on the guidance from EPRI Closed Cooling Water Chemistry Guidelines and good industry practices. The EPRI Closed Cooling Water Chemistry Guideline indicates that an action level 1 or level 2 should be followed when one control parameter is not in compliance with the guidelines. However, the EPRI Closed Cooling Water Chemistry Guideline indicates that more aggressive actions may be necessary if multiple control parameters are not in compliance with the guidelines. The staff could not determine if there are procedures at DAEC that describe what actions are take if more than one control parameter is out of compliance with the EPRI Closed Cooling Water Chemistry Guideline.

Request

Provide additional information describing if any specific actions different than the Level 1 or Level 2 actions would be taken if more than one control parameter are out of compliance with the EPRI Closed Cooling Water Chemistry Guidelines.

DAEC Response to RAI B.3.15-2

The DAEC closed cooling water systems chemistry guidelines have been revised to include written guidance for the Chemistry Supervisor or technician to recommend that more aggressive corrective actions be initiated in the event more than one control parameter is out of compliance with the established guidelines than would be the case if only one control parameter were out of compliance.

RAI B.3.15-3

Background

The parameters monitored/inspected, described in the Closed-Cycle Cooling Water System Program in NUREG-1801, Rev. 1, Section XI.M21 indicates that the guidance in EPRI TR-107396 may be used to monitor corrosion inhibitor system to mitigate general, crevice, and pitting corrosion as well as stress corrosion cracking.

Issue

The DAEC LRA, Appendix B, Section B.3.15 indicates that the applicant's Closed-Cycle Cooling Water System Program is consistent with the NUREG-1801, Rev. 1 Section XI.M21 and does not take any exceptions. In addition, the applicant indicates that it maintains the closed-cycle cooling water system corrosion chemistry within specified limits of EPRI Closed Cooling Water Chemistry Guidelines. The EPRI Closed Cooling Water Chemistry Guideline in Table 5-1 indicates that azoles are a monitored parameter unless it can be documented that there are no copper alloys in the system. The LRA indicates in Section 3.3.1.22 that the reactor building closed cooling water system contains copper. However, the basis documents do not appear to indicate that azoles are used in the reactor building closed cooling water system. It is not clear to the staff why azoles are not used in the reactor building closed cooling water system when it contains copper components.

Request

Provide additional information describing why azoles are not used and monitored in the reactor building closed cooling water system as suggested in the EPRI Closed Cooling Water Chemistry Guidelines.

DAEC Response to RAI B.3.15-3

The Reactor Building Closed Cooling Water (RBCCW) system soluble copper historically has been less than 100 ppb. The industry best practices recommended range is less than 200 ppb. DAEC determined that the use of azoles in the RBCCW would be unlikely to provide a measurable reduction in the system soluble copper levels.

RAI B.3.16-1

Background

In license renewal application (LRA) Section B.3.16, the applicant stated that the Compressed Air Monitoring Program is an existing program with no exception to Generic Aging Lessons Learned (GALL) Aging Management Program (AMP) XI.M24. The applicant also stated that the program manages and mitigates the aging effect of corrosion and [is] assuring an oil free dry air environment in the instrument air system. LRA Section 18.1.16 describes the Updated Final Safety Analysis Report (UFSAR) Supplement and states that the applicant's program manages or mitigates aging effects of the instrument air system.

Similarly, UFSAR Revision 14, Section 9.3.1.2.3, "Testing and Inspection Requirements" (for the instrument and service air system) states that: The instrument and service air systems operate continuously and are observed and maintained during normal operations. An instrument air system blowdown is performed periodically to remove any possible particulates from the system. Also an instrument air quality test is performed periodically at various instrument air headers downstream of air driers. This test is performed to verify that the air quality [dew point, particulate and oil content] is consistent with the manufacturer recommendation.

In contrast, LRA Section 3.3.1.15 indicates that the Compressed Air Monitoring Program is not credited for the instrument air system, while the applicant credited the Bolting Integrity Program, External Surfaces Monitoring Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for the aging management of the instrument air system.

In addition, LRA Section 3.3.1.27 indicates that the applicant credited the Compressed Air Monitoring Program for the safety-related air system to manage the aging effect of loss of material. The staff also noted that UFSAR, Revision 14, Section 9.3.1.2.1, "Description" under Section 9.3.1.2, "Instrument and Service Air System" states that a safety-related air system is provided as a backup to the normal instrument air system for several critical safety-related components and systems. The staff also noted that in the UFSAR Section 9.3.1.2 for the instrument and service air system is under Section 9.3.1, "Compressed Air Systems".

Issue

The staff found a need to clarify whether the Compressed Air Monitoring Program manages the aging effects and performs the relevant inspection, monitoring and testing for the applicant's instrument air system and safety-related air system in accordance with the GALL Report.

Request

1. Clarify why LRA Section 3.3.1.15 and LRA Table 3.3.2-15 for the instrument air system indicate that the Compressed Air Monitoring Program is not credited for the instrument air system, which is in apparent conflict with the descriptions in the LRA Section B.3.16 and UFSAR Section 9.3.1.2.3 suggesting that the Compressed Air Monitoring Program manages the aging effects of the compressed air systems including the instrument air system as well as the safety-related air system.
2. Clarify whether the Compressed Air Monitoring Program manages the aging effects of the compressed air system(s) including the instrument air and safety-related air systems and performs inspection, monitoring and testing for the systems in accordance with GALL AMP XI.M24 as the applicant claimed its consistency with the GALL Report.
3. Clarify why the UFSAR Supplement in LRA Section 18.1.16 includes only the instrument air system although the Compressed Air Monitoring Program is also credited for the safety-related air system. Clarify whether the description "instrument air system" in the UFSAR Supplement needs to be changed to the "compressed air systems" or relevant system description terminology in such a way to encompass the instrument air system, safety-related air system and other relevant systems as applicable.

DAEC Response to RAI B.3.16-1

Part 1

LRA Section 3.3.1.15 and LRA Table 3.3.2-15 do not credit the Compressed Air Monitoring Program because this program is only identified in the GALL as managing the aging effects of compressed air system components subject to aging management review that have a condensation internal environment. The only instrument air system components at DAEC that are subject to license renewal aging management review are a section of safety related piping and isolation valves that make up a primary containment boundary; and the cooling water components to the standby instrument air compressor 1K001 that could spatially affect safety related equipment located in the Turbine Building. Since the instrument air system components that make up the primary containment boundary are safety related, they are included within the scope of license renewal; however, since they remain isolated, their internal environment is not affected by variations in air quality that would be monitored by the Compressed Air Monitoring Program. The 1K001 Compressor cooling water components contain an open cycle cooling water system fluid, and they do not include the condensation environment that would be managed by the Compressed Air Program. The remaining components of the Instrument Air System are not safety related, do not contain fluids that could affect safety related equipment, and are not credited for supporting an augmented event specified as having a license renewal intended function.

The existing DAEC Compressed Air Monitoring Program is a system monitoring program required to assure that the system conditions are maintained to limit aging effects. The DAEC Compressed Air Program implements NRC Generic Letter 88-14, INPO SOER 88-01 and applies to all compressed air systems at DAEC even though not all of the DAEC compressed air components are included within the scope of license renewal. The DAEC Compressed Air Monitoring Program indirectly manages the Instrument Air System and Safety Related Air System aging effects by monitoring air system parameters such as entrained particulates, dew point, and oil concentration. Preventative maintenance tasks and scheduled surveillances blow down instrument and safety related air system dead legs and safety related receivers as well as collect samples for testing. In addition, the dew point is monitored daily and instrument air system dryer fault conditions including high outlet moisture are alarmed in the control room. Monitoring the Instrument Air and Safety Related Air system parameters ensures the system internal environments are properly managed to prevent aging effects due to corrosion and ensures that no air quality induced failures of the safety related components they supply.

Part 2

The Compressed Air Monitoring Program manages the aging effects of both the instrument air system and the safety related air system. The Compressed Air Monitoring Program age manages the air supplied to the Instrument Air System, Breathing Air System (abandoned in place) and the Safety Related Air System.

Part 3

The description in the UFSAR Supplement is being clarified to indicate that the instrument air system and safety related air system are both recognized as being age managed under license renewal.

LRA Appendix A, Section 18.1.16, Compressed Air Monitoring Program, on page A-8, is revised in its entirety to read as follows:

> The Compressed Air Monitoring Program consists of inspection, monitoring, and testing of the compressed air systems (Safety Related Air, Instrument Air, Service Air, and Breathing Air), including (1) leak testing of valves, piping, and other system components, especially those made of steel and stainless steel; and (2) preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits.
>
> This program is in response to NRC GL 88-14 and INPO Significant Operating Experience Report (SOER) 88-01. It also relies on the ASME OM Guide Part 17, and ISA-S7.0.1-1996 as guidance for testing and monitoring air quality and moisture.

RAI B.3.16-2

Background

In LRA Section B.3.16, the applicant stated that the Compressed Air Monitoring Program is an existing program with no exception to the GALL Report. In LRA Section 18.3.16, the applicant provided the UFSAR Supplement for the Compressed Air Monitoring Program.

The Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR; NUREG-1800, Rev. 1) provides the Final Safety Analysis Report (FSAR Supplement for the Compressed Air Monitoring Program in Table 3.3-2 (page 3.3-37). The SRP-LR requires that the applicant's UFSAR Supplement (or equivalent) should be compared against the FSAR Supplement in the SRP-LR to confirm the equivalency between them.

Issue

In its review, the staff found a need to clarify whether the applicant's UFSAR Supplement for the Compressed Air Monitoring Program is equivalent to the FSAR Supplement in the SRP-LR in the following areas. The applicant's UFSAR Supplement did not clearly indicate:

1. Whether the AMP performs inspection, monitoring and testing of the entire system including frequent leakage testing valves, piping and other system components especially those made of steel.
2. Whether the AMP is in response to NRC GL 88-14 and INPO's Significant Operating Experience Report (SOER) 88-01.
3. Whether the description "instrument air system" in the UFSAR Supplement needs to be changed to the "Compressed Air Systems" or relevant terminology for system description in such a way to encompass the instrument air system, safety-related air system and other relevant system as applicable (See RAI B.3.16-1, also).

Request

1. Describe how, if applicable, the UFSAR Supplement for the Compressed Air Monitoring Program will be revised to resolve the potential discrepancies between the SRP-LR and the applicant's UFSAR Supplement as described in the foregoing "Issue" section: 1) performance of inspection, monitoring and testing of the entire system including leakage testing, 2) clarification of the applicable basis references (GL 88-14 and INPO SOER 88-01) and 3) use of relevant terminology for system description.

DAEC Response to RAI B.3.16-2

As discussed in the response to RAI B.3.16-1, the UFSAR Supplement for the Compressed Air Monitoring Program has been revised to incorporate the requested information.

RAI B.3.16-3

Background

In LRA Section B.3.16.1, which provides the program description of the Compressed Air Monitoring Program, the applicant stated that a semi-annual air system quality check is performed as part of the monitoring activities of the program. The applicant also stated that the applicant program is consistent with the GALL Report with no exception. In addition, applicant's on-site AMP Document, License Renewal Application Project (LRAP)-M024 Compressed Air Monitoring, indicated that the plant Auxiliary Operator Log records system and equipment parameters each shift and the parameters to record include instrument air dew point and system pressure (see page 12).

In comparison, ISA-S7.0.01-1996, "Quality Standard for Instrument Air," which is one of the technical references of GALL AMP XI.M24 states that a monitored alarm for the pressure dew point is preferred; however, if a monitored alarm is unavailable, shift monitoring is recommended.

Issue

The staff noted that the on-site documentation for the program references included applicant's surveillance test procedure (STP), NS180001, "Instrument Air Quality" and the procedure describes air quality tests, which are oil concentration test, dew point test and particulate size and concentration test. However, the staff found that the surveillance test procedure does not specify the test frequencies for the air quality tests in contrast to the semi-annual air system check described in LRA Section B3.16. Therefore, the staff found a need to clarify how the frequencies of the air quality tests are specified and controlled in the applicant's program.

The staff also reviewed pages 8, 16 and 17 of applicant's Auxiliary Operator's Log, Revision 103, as provided as part of the on-site documentation by the applicant and found the dew point is one of the parameters to record on the log. However, the staff found that the Auxiliary Operator Log does not specify the frequency of recording the dew point.

Request

1. Clarify how the frequencies of the air quality tests per STP NS180001 are specified and controlled.
2. Clarify how the frequency of monitoring the dew point data with the Auxiliary Operator's Log is specified and controlled. Confirm whether the frequency of the dew point monitoring is consistent with the recommendation of ISA-S7.0.01-1996, which is shift monitoring.

DAEC Response to RAI B.3.16-3

Part 1
The pre-planned task (PPT) in the work maintenance database (WPI) controls the frequency of NS180001; the task is currently specified to be performed every 6 months.

Part 2
The operations department instructions specify that the Plant Equipment Operators should take at least one set of logs per shift in their assigned areas of responsibility. This is consistent with Section 5.1 of ISA-7.0.01-1996 which states that per shift monitoring is recommended.

RAI B.3.16-4

Background

In LRA Section B.3.16.5, which described the operating experience with the Compressed Air Monitoring Program, the applicant stated that: Corrosion products were found in the instrument air receiver tanks and in the accessible sections of the air receivers supply piping. Modifications included replacement of the carbon steel underground piping (in 2007) with stainless steel piping and the installation of blowdown piping on the Y-strainers associated with the instrument air receiver tanks to allow the Y-strainers to be cleared by blowing them down which allowed the downstream drain taps to perform their water removal function more reliably.

In addition, applicant's on-site AMP Document, LRAP-M024 Compressed Air Monitoring, addressed CAP030621 (1T055A Instrument Air Tank Has Min wall of 0.224 & UT Readings down to 0.077", February 5, 2004) as part of the operating experience with the Compressed Air Monitoring Program.

The Detailed Description section of CAP030621 indicated that: A work order was written to take UT readings on the lower portion of 1T055A (instrument air receiver tank) to determine the wall thinning due to internal corrosion. The bottom head is nominal wall of 0.344". [The] minimum wall based on hoop stress is 0.224. Four small areas indicate wall thickness of 0.224 down to 0.181, 0.094, 0.082 and 0.077. Need [was identified] to evaluate for continued acceptance and/or repair.

EPRI/NMAC NP-7079, "Instrument Air System," is one of the technical references of GALL AMP XI.M24, "Compressed Air Monitoring" and in relation with instrument air receivers, NP-7079, Section 2.0 (pages 4 and 5) states that: In some systems, air from the after cooler enters a moisture separator for final water removal, thus protecting the receiver from moisture accumulation. The compressed air temperature at the outlet of the after cooler may still be above the plant ambient temperature, in which case further cooling and condensation occurs in the air receiver. Plants without a moisture separator usually provide drain taps and receiver blowdown. Finally, the compressed air enters the receiver, acts as a storage tank and pressure surge buffer for the distribution system.

Issue

The staff found a concern that the wall thinning of the instrument air receiver tank due to internal corrosion degrades the integrity of the air receiver tank. The staff also noted that the internal corrosion of the air receiver tank can degrade air-operated equipment by generating and releasing corrosion products to the air distribution system.

Request

1. Describe how the wall thinning evaluation was performed for continued acceptance and/or repair of the four small areas, which indicated thickness less than the minimum wall thickness based on hoop stress as described in CAP030621. In addition, describe what actions were taken to prevent and mitigate the wall thinning and internal corrosion of the air receiver tank.
2. Clarify whether the applicant's instrument air system has moisture separator(s) at the upstream of the instrument air receiver(s) as addressed in Electric Power Research Institute (EPRI) NP-7079, Section 2.
3. Describe how the applicant's program prevents or mitigates the wall thinning and internal corrosion of the air receiver tank. In addition, describe how the applicant's program prevents or mitigates the transport of corrosion products and contaminants from the air receiver tank and its upstream portions to the other downstream portions of the air distribution system.
4. Using the operating experience, clarify whether the corrosion and wall thinning observed in the air receiver tank have adversely affected the performance or integrity of the air-operated equipment and components in the applicant's compressed air system(s).

DAEC Response to RAI B.3.16-4

Part 1

The wall thinning evaluation was done as an ASME Section VIII calculation. The ID weld build up of the bottom head was done using an ASME Section IX qualified procedure and ASME qualified Welder. Completed weld repair areas were examined using VT & MT and found acceptable. There was no specific action taken to prevent the wall thinning and internal corrosion of the air receiver tank, but preventive maintenance activities were issued to perform UT measurements on the receiver tanks every three years to confirm the air receiver tanks continue to maintain their minimum wall thickness for continued operation.

Part 2

The system design does not include moisture separators upstream of the instrument air receivers. EPRI-NP-7079 states that plants without moisture separators provide drain traps and receiver blowdown valves. Drain traps are installed in drain lines off the bottom of the air receiver tanks. Blowdown piping and valves are installed on the Y-strainers associated with the Instrument Air receiver tanks to allow the Y-strainers to be cleared by blowing them down. This allows the downstream drain traps to perform their water removal function more reliably.

Part 3

The moisture removal methods identified in part 2 prevent and mitigate the buildup of condensate which produces a corrosive environment. The effectiveness of maintaining condensate out of the air receiver tanks to prevent corrosion is monitored by the performance of periodic preventive maintenance inspections on the air receiver tanks. As discussed in part 1, UT thickness measurements are performed every three years to verify there is no excessive corrosion occurring in the air receiver tanks. The transport of corrosion products to the downstream portions of the air distribution system in the Instrument Air piping is prevented by separators and filters, and its effectiveness is monitored by the performance of an Instrument Air System blowdown and air dryer swap every three months. The downstream piping for the Service Air piping is blown down by the performance of this procedure.

Part 4

The corrosion and wall thinning identified in the Air Receiver tank has not adversely affected the performance or integrity of the air-operated equipment or components in the compressed air systems, based on an SOER Effectiveness Review report dated 3/10/09. There have been no failures of point-of use components due to poor air quality in the Instrument Air System. This review indicates that the Compressed Air Monitoring Program is effective in maintaining the quality of air in the Compressed air systems. In addition the Instrument Air System Health Report indicates that there have not been any Instrument Air Transients resulting in a balance of plant isolation since 1993.

RAI B.3.18-1

Background

GALL AMP XI.E2, under Scope of Program, states that this program applies to electrical cable and connections used in circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation that are subject to an AMR. In the applicant's basis document LRAP-E002, under Scope of Program, it states that the cables in the scope of license renewal are in the nuclear instrumentation system, and there are no radiation monitoring system cables in the scope of this AMP.

Issue

Per GALL AMP XI.E2, the radiation monitoring system cables are in the scope of license renewal because they perform an intended function. These cables are used in sensitive, high voltage, low level signals. Exposure of these electrical cables to adverse localized environments caused by heat, radiation, or moisture can result in reduced insulation resistance (IR). Reduced IR can cause an increase in leakage current between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, high voltage, low-level signals such as high-range radiation monitoring system.

Question

Explain why radiation monitoring system circuits are not included in the scope of Electrical Cables and Connections Used in Instrumentation Circuits AMP.

DAEC Response to RAI B.3.18-1

Instrumentation cables for Radiation Monitoring systems are not in the scope of the Electrical Cables and Connections Used in Instrumentation Circuits Program because either they are included in the 10CFR50.49 Environmental Qualification Program, or they are not located in adverse localized environments. Duane Arnold defines adverse localized environments for instrumentation cable as areas with radiation dose greater than 3×10^7 rads and/or temperature greater than 60°C (140°F). The Radiation Monitoring System instrumentation cables that are not included in the Environmental Qualification Program are in areas where the maximum design dose is 5.3×10^4 rads and maximum design temperature is 40°C (104°F). The Radiation Monitoring System instrumentation cables are designed and qualified for this environment.

RAI B.3.21-1

Background

In the LRA B.3.21, of the External Surface Monitoring Program, the applicant states this to be an existing program and consistent with the ten elements of GALL, XI.M36 program. The applicant also states that elements, Scope of the Program, Parameters Monitored or Inspected, Monitoring and Trending, and Acceptance Criteria need enhancements.

Issue

In TABLE A-1 of the Supplement 1, dated January 22, 2009, the applicant makes a commitment to the existing program, to assure revision of "the inspection program to address inspector qualifications, types of components, degradation mechanisms, aging effects, acceptance criteria, and inspection frequency."

Request

The LRA has no enhancements related to aging effects program element, yet there is a commitment to this effect. Identify the specific enhancement related to aging effects as discussed in the commitment.

DAEC Response to RAI B.3.21-1

At DAEC External Surfaces Monitoring Program element, Detection of Aging Effects, is consistent with NUREG-1801 XI.M36 Element 4, Detection of Aging Effects. The program is credited with managing the aging effect of loss of material which is consistent with the requirements of NUREG 1801 XI.M36 Element 4.

Commitment 8 in LRA Table A-1 states, "Revise the inspection program to address inspector qualifications, types of components, degradation mechanisms, aging effects, acceptance criteria, and inspection frequency."

The reference to aging effects in Commitment 8 comes from the wording of the enhancement of Element 6, Acceptance Criteria, in LRA Section B.3.21.4, Enhancements to Duane Arnold Program. This enhancement states, "Enhance the system walkdown to more specifically address the acceptance criteria for the component / aging effect combination to be sure that corrective actions will be identified before loss of intended function, and periodic reviews to determine program effectiveness."

Therefore, the wording related to aging effects in Commitment 8 addresses the enhancement for element 6, Acceptance Criteria. Note that the response to RAI B3.21-2 below revises the wording of commitment 8, but the changes do not affect the response to this RAI.

RAI B.3.21-2

Background

GALL in element #1, Scope of Program discusses inaccessible areas that need to be inspected at intervals to provide reasonable assurance that aging effects will be managed. In addition, the same element discusses how to inspect insulated external surfaces so that there is a reasonable assurance the effects of aging will be managed.

Issue

There are no apparent discussions in the current system engineering walkdown procedure regarding inaccessible areas and the inspection of insulated external surfaces. The LRA enhancements do not address these aspects.

Request

Please provide specific enhancement details to this program element regarding walkdowns of inaccessible areas and insulated external surfaces.

DAEC Response to RAI B.3.21-2

In LRA Section B.3.21.4 on page B-46, the entry for bullet Scope of Program is revised to read as follows:

- Scope of Program

  Enhance the system walkdowns to more specifically address inaccessible areas, the types of components to be inspected, the relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, and the inspections of opportunity for possible corrosion under insulation.

To reflect this change to the enhancement, Commitment 8 in LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is revised as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
8.	External Surfaces Monitoring Program	Revise the inspection program to address inspector qualifications, types of components, degradation mechanisms, aging effects, acceptance criteria, inspection frequency, and periodic reviews to determine program effectiveness. The program will also specifically address inaccessible areas and include inspections of opportunity for possible corrosion under insulation.	18.1.21	Prior to the period of extended operation

RAI B.3.21-3

Background

The supporting documentation to this AMP, LRAP-M036, Revision 3 in this program element discusses the application of specific (class I, II, III) insulation in systems of piping having higher temperatures which would then preclude a wetted external surface.

Issue

Depending on the leak rate, the insulated external surface could be exposed to a wetted environment. The assumption that high temperature will preclude the formation of a wetted external surface for the extended period may not be valid.

Request

Please provide additional basis for apparent exclusion of insulating classes I, II, III from the inspection walkdowns.

DAEC Response to RAI B.3.21-3

EPRI 1010639, Non Class I Mechanical Implementation Guidelines and Mechanical Tools, Appendix E, Section 2.2.1 states, "The external surfaces of components in systems with lower than ambient internal fluid temperatures (e.g., Chilled Water, Service Water, etc.) are expected to be intermittently or frequently wetted due to condensation, whereas components in high temperature systems (e.g., Main Steam, Feedwater, etc.) are expected to have external surface temperatures >212°F which precludes moisture accumulation." The Insulation Schedule for Class I, II, and III insulated piping indicates that operating temperatures are >251°F.

High temperature piping precludes wetted external surface environments (no condensation), and DAEC does not have high temperature insulated piping in scope of license renewal that is located outdoors. Therefore a wetted external surface would not exist for extended periods for insulation Class I, II, or III insulated piping.

Components in indoor locations could be exposed to alternate wetting and drying due to leakage from plant fluid systems or could temporarily come in contact with aggressive chemicals resulting from accidental spills. However, the aging effects that could result from the leakage or spills are considered rare and event driven and as such are not considered a chronic condition of the environment that requires evaluation for long term aging. Leaking insulated surfaces (low or high temperature) would be discovered during normal plant activities, documented in the Corrective Action Program, insulation removed (inspection of opportunity) and the leak repaired or mitigated in a short period of time.

Low temperature piping in an indoor or outdoor environment could have a wetted external surface environment under its insulation (e.g., from condensation or rain water) for extended periods without being detected. For such surfaces that are insulated, inspections of opportunity will be performed to assess the external condition when insulation is removed for maintenance or inspection. If there were insufficient opportunities for inspection, insulation will be removed from additional sample locations to assess system condition under insulation due to the entrapment of condensation or rain water.

RAI B.3.21-4

Background

GALL program element #5, Monitoring and Trending, states, "Deficiencies are documented using approved processes and procedures such that results can be trended." The supporting documentation to this AMP, LRAP-M036, Revision 3 in the Monitoring and Trending program element states the External Surfaces Monitoring Program uses a plant-specific instructions/checklist for the license renewal aging management walkdowns.

Issue

The current walkdown procedure, apparently does not include a plant-specific checklist for the licensing renewal AMP. The enhancement for Monitoring and Trending program element, however, addresses qualifications of inspection personnel and periodic reviews to determine program effectiveness.

Request

Please clarify the enhancements regarding the inclusion of procedural requirements for the license renewal aging management walkdowns.

DAEC Response to RAI B.3.21-4

As part of Commitment #8, the procedural guidance for system walkdowns credited by the External Surfaces Monitoring Program is being enhanced to more specifically address the types of components to be inspected, the relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, the inspections of opportunity for possible corrosion under insulation, the qualifications required for inspection personnel, and the acceptance criteria for the component/aging effect combination to be sure that corrective actions will be identified before loss of intended function.

Walkdowns are to be performed using the guidance of EPRI Technical Report 1009743 "Aging Identification and Assessment Checklist," August 27, 2004, to manage aging degradation of external surfaces.

Trending is to be performed using the Program Health Process to provide periodic reviews to determine program effectiveness.

RAI B.3.22-1

Background

LRA AMP B.3.22, Fire Protection program has taken an exception for "detection of aging effects" and "monitoring and trending" program elements as follows:

DAEC Fire Plan – Volume 1, Program reflects the current Duane Arnold licensing bases as defined in License Amendment Number 132. This amendment allows the frequency of the visual inspections for the walls, ceilings, and floors use as fire barriers to be performed at an interval of 35 per cent once each operating cycle with 100 per cent visually inspected within a period of five years.

Issue

However, License Amendment Number 132, as approved by NRC SE dated April 24, 1986 addresses inspection frequencies of fire barrier penetration seals, and not walls, ceilings and floors.

Request

Please confirm if the exception should be addressing fire barrier penetration seals and indicate what happens after the five-year period.

DAEC Response to RAI B.3.22-1

Fire Barrier Penetration Seals are discussed in the response to RAI B.3.22-2.

The DAEC Fire Barrier Penetration Seal surveillance performs a visual inspection of 35 percent of fire barrier walls, ceilings and floors at an 18 month interval such that 100 percent are inspected every 5 years. The subsequent 5 year periods continue with this same inspection frequency. As discussed in LRA Section B.3.22.4 on page B-47, this is considered an exception to the GALL AMP XI.M26, Fire Protection Program, which requires these inspections once per refueling cycle.

DAEC has not experienced significant concrete deterioration or degradation; therefore, this inspection interval is adequate to detect any fire barrier degradation prior to loss of intended function.

For clarity, LRA Section B.3.22, Fire Protection Program, Subsection B.3.22.4, Enhancement to Duane Arnold Program, on page B-47, is revised in its entirety to read as indicated below. Note that changes have also been incorporated to also reflect responses to RAIs B.3.22-2 through B.3.22-6.

B.3.22.4 ENHANCEMENTS TO DUANE ARNOLD PROGRAM

The program requires enhancements to be consistent with the following elements:

- Parameters Monitored/Inspected, Detection of Aging Effects, Monitoring and Trending and Acceptance Criteria

  The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to include criteria for visual inspections of fire barrier walls, ceilings and floors to examine for any sign of degradation such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack and reaction with aggregates by fire protection qualified inspectors.

  The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to ensure a approximately 10% of each type of penetration seal is included in the 35 percent selection of fire penetration seals that are visually inspected at an 18 month interval.

  The DAEC Surveillance Procedure for the CO_2 Cardox System Operability Annual Test will be enhanced to include a step to perform an inspection for corrosion and mechanical damage to system components.

  The Fire Protection Program will be enhanced to inspect the entire Diesel Driven Fire Pump fuel supply line for degradation (any component in a state of disrepair).

To reflect the changes to Fire Protection Program enhancements incorporated into the LRA, one commitment is revised and two new commitments are made, as indicated below:

In LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal, Commitment 9 is revised to read as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
9.	Fire Protection Program	The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to include criteria for visual inspections of fire barrier wall, ceiling and floors to examine for any sign of degradation such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack and reaction with aggregates by fire protection qualified inspectors.	18.1.22	Prior to the period of extended operation

In LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, two new commitments are added as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
43.	Fire Protection Program	The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to ensure a approximately 10% of each type of penetration seal is included in the 35 percent selection of fire penetration seals that are visually inspected at an 18 month interval.	18.1.22	Prior to the period of extended operation
44.	Fire Protection Program	The DAEC Surveillance Procedure for the CO2 Cardox System Operability Annual Test will be enhanced to include a step to perform an inspection for corrosion and mechanical damage to system components.	18.1.22	Prior to the period of extended operation

Note that the fourth enhancement related to Diesel Fire Pump testing is already addressed as Commitment 10.

RAI B.3.22-2

Background

GALL AMP XI.M26, "Fire Protection," states in "parameters monitored/inspected" program element that visual inspection of approximately 10% of each type of penetration seal is performed during walkdowns carried out at least once every refueling outage.

Issue

It is not clear if the 35% of penetration seals that are inspected during each operating cycle includes each type of penetration seal.

Request

Please confirm if the 35% sample of penetrations seals visually inspected include each type of penetration and if not, please justify why this is not an exception to the GALL AMP XI.M26

DAEC Response to RAI B.3.22-2

The DAEC Fire Protection Program does not have an exception to NUREG-1801 XI.M26 for inspection of each type of fire barrier penetration seal. While the procedural controls on penetration seals do not currently include a specific requirement for an inspection of each type of seal, a program enhancement has been identified in the response to RAI B.3.22-1 above to ensure approximately 10% of each type of penetration seal is included in the 35 percent selection of fire barrier seal penetrations that are visually inspected every 18 months as required by the DAEC Fire Plan.

RAI B.3.22-3

Background

GALL AMP XI.M26, "Fire Protection," states in "parameters monitored/inspected" and "detection of aging effects" program elements that periodic visual inspection and function test is performed at least once every six months to examine the signs of degradation of the halon/CO_2 fire suppression system.

Issue

Review of the DAEC Fire Protection Program basis document indicates that performance testing and visual inspection of CO_2 fire suppression system is done annually, however; there is no exception taken in the LRA.

Request

Please justify why an exception to the GALL AMP is not addressed in the LRA. If an exception is taken, please provide the basis of the exception.

DAEC Response to RAI B.3.22-3

The DAEC Operating Experience and Work Request history for CO_2 fire Suppression System (Carbon Dioxide Fire Protection System) have not shown signs of degradation on passive components. There have been, however, a few repairs of active equipment. Performance of the CO_2 Cardox System operability test removes this fire suppression system from service. Based on the DAEC operating experience, it is concluded that performing the visual inspection and the functional test annually is adequate. This test frequency will be considered an exception to the GALL inspection frequency of once every six months.

In LRA Section B.3.22, Fire Protection Program, Subsection Section B.3.22.3, Exceptions to NUREG-1801, is revised in its entirety to read as indicated below. Note that changes have also been incorporated to reflect responses to RAIs B.3.22-2 through B.3.22-6.

B.3.22.3 EXCEPTIONS TO NUREG-1801

The DAEC program takes two exceptions to the guidance as stated in NUREG-1801 XI.M26. These exceptions affect the following elements of NUREG-1801 XI.M26:

- Detection of Aging Effects, Monitoring and Trending

  Inspections of 35 percent of fire barriers, walls, ceilings and floors will be conducted every 18 months with 100 per cent visually inspected within five years. NUREG-1801 XI.M26 recommends that these inspections be performed every refueling cycle.

- Parameters Monitored/Inspected, Detection of Aging Effects

  The CO_2 Cardox System Operability Test procedure examines the CO_2 fire suppression system for the cable spreading room annually for signs of degradation (e.g., corrosion, mechanical damage, or damage to dampers). NUREG-1801 XI.M26 recommends inspection every six months.

To reflect the changes incorporated into this program, LRA Appendix A, Section 18.1.22, Fire Protection Program, is revised in its entirety to read as follows:

18.1.22 FIRE PROTECTION PROGRAM

The Fire Protection Program manages aging effects of fire protection components using surveillance test procedures and detailed inspections. Surveillance tests are performed on the diesel-driven fire pump, the CO_2 fire suppression system, fire doors, and fire barrier penetration seals. Visual inspections for degradation are performed on fire barrier walls, ceilings and floors.

This program is consistent with the ten elements of NUREG-1801 XI.M26 with the following two exceptions to NUREG-1801 XI.M26.

- Inspections of 35 percent of fire barriers, walls, ceilings and floors will be conducted every 18 months with 100 per cent visually inspected within five years. NUREG-1801 XI.M26 recommends that these inspections be performed every refueling cycle.

- The CO_2 Cardox System Operability Test procedure examines the CO_2 fire suppression system for the cable spreading room annually for signs of degradation (e.g., corrosion, mechanical damage, or damage to dampers). NUREG-1801 XI.M26 recommends inspection every six months.

RAI B.3.22-4

Background

GALL AMP XI.M26, "Fire Protection," states in "detection of aging effects" program element that visual inspections of the halon/CO_2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. GALL AMP XI.M26 states in "acceptance criteria" program element that any signs of corrosion and mechanical damage of the halon/CO_2 fire suppression system are not acceptable.

Issue

Review of the DAEC Fire Protection Program basis document, and supporting surveillance test procedure document for Cardox System Operability Test indicated that this procedure only addresses performance testing and did not include visual inspection.

Request

Please explain how DAEC proposes to meet the GALL AMP recommendation to detect any sign of corrosion and mechanical damage of the CO_2 Cardox system.

DAEC Response to RAI B.3.22-4

As indicated in the response to RAI B.3.22-1, the Fire Protection Program description in LRA Section B.3.22 has been revised to incorporate an enhancement for the DAEC Surveillance Procedure for the CO_2 Cardox System Operability Annual Test to perform an inspection for corrosion and mechanical damage to system components.

RAI B.3.22-5

Background

GALL AMP XI.M26, "Fire Protection," states in "detection of aging effects" program element that visual inspection by fire protection qualified inspectors of the fire barrier walls, ceilings, and floors, performed in walkdowns at least once every refueling outage ensures timely detection of concrete cracking, spalling, and loss of material.

Issue

Review of the DAEC Fire Protection Program basis document, Section 3.4.2, indicates that fire barriers are inspected once every five years, and that this is an exception to the GALL AMP interval of once every refueling outage. Furthermore, the same section also references Structures Monitoring Program and identifies a ten-year inspection cycle. The LRA AMP B.3.22, Fire Protection Program, does not identify this as an exception to the GALL AMP XI.M26.

Request

Please justify why this is not an exception and provide the basis for the exception. Also please explain if the ten-year inspection using the Structure Monitoring Program is in addition to the Fire Protection Program inspections or in lieu of the Fire Protection program inspection.

DAEC Response to RAI B.3.22-5

As indicated in the response to RAI B.3.22-3, LRA Section B.3.22, Fire Protection Program, has been revised to reword the exception related to the fire barrier inspection program. As discussed in that RAI response, DAEC has not experienced significant concrete deterioration or degradation; therefore, this inspection interval is adequate to detect any fire barrier degradation prior to a loss of intended function.

The DAEC Fire Barrier Penetration Seal Inspection surveillance performs a visual inspection of 35 percent of fire barrier walls, ceilings and floors in the "Fire Barrier Scan" portion of the surveillance. This surveillance is performed on an 18 month frequency with 100 percent of fire barrier wall, ceilings and floors inspected within 5 years. As discussed in the response to RAI B.3.22-1, this surveillance will be enhanced to perform integrity inspections of fire barrier walls, floors and ceilings that look for concrete cracking, spalling and loss of material.

The DAEC Maintenance Rule Program for Monitoring of Structures will not be credited with the Fire Protection inspection of walls, floors and ceilings at a five and ten year cycle. Reference to Maintenance Rule Monitoring is being removed from the DAEC Fire Protection Program basis document.

RAI B.3.22-6

Background

LRA B.3.22, Fire Protection Program, in Section B.3.22.5, states that "DAEC performs a biennial assessment of the Fire Protection Program. The most recent assessment concluded that, on an overall basis, the Fire Protection Program is satisfactory."

Issue

Staff review of DAEC operating experience identified a CAP040770 dated March 7, 2006 that was written to address the Fire Protection self assessment of Penetration Seal Program Effectiveness. This CAP identified several issues with the penetration seal program and warranted the classification of penetration seal program as an issue of attention. The penetration seal program inspections are performed under seal inspection procedure STPNS13F001, which was used by DAEC as the basis to establish consistency with GALL AMP XI.M26.

Request

Please explain why this plant operating experience was not included in LRA Section B.3.22.5. Please also identify the corrective actions taken to confirm that the Fire Protection Program will provide reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

DAEC Response to RAI B.3.22-6

LRA Section B.3.22.5 did not include the issues identified in CAP040770 because they dealt primarily with configuration control, timeliness in updating configuration control and timeliness in communicating inspection results. CAP040770 did not identify any new aging effects or failures of the program to detect and correct aging of fire barrier penetration seals.

Corrective actions have been completed to improve configuration control by establishing a controlled engineering document for fire barrier penetration seals and by improving surveillance procedures to require prompt communication of inspection results.

RAI B.3.23-1

Background:

GALL AMP XI.M27, "Fire Water System," states in "detection of aging effects" program element that fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur.

Issue:

The DAEC Fire Water System program basis document states that STP-NS13E006, Fire Hose Hydrostatic Pressure Testing procedure provides the guidance to perform the fire hydrant hose hydrostatic tests and gasket inspection annually. However, Section 4.1 of the procedure, the drywell access cabinet, fire brigade assembly area, and B5b hose hydrostatic pressure tests are performed every 3 years.

Request:

Please justify why this is not identified as an exception to the GALL AMP XI.M27 in the LRA. If it is an exception, please provide the basis for the 3-year test frequency.

DAEC Response to RAI B.3.23-1

At DAEC, fire hoses are considered consumables that are replaced based on performance or condition monitoring that identifies when the hoses reach the end of their qualified life; therefore, they may be excluded from AMR under 10 CFR 54.21(a)(1)(ii). The standard that is used to test the performance of the fire hoses is provided by the National Fire Protection Association. The allowance for this AMR exclusion is provided in NUREG-1800, Table 2.1-3. The DAEC Fire Water System program basis document should not have listed STP-NS13E006 in section 5.0 "Summary of Implementing Documents/Responsible Department and section 6.0 "References".

RAI B.3.24-01

Background

GALL Section XI.M17, "Flow-Accelerated Corrosion," states that the program relies on implementation of the guidelines in NSAC-202L-R2 for an effective flow-accelerated corrosion program. DAEC LRA Section B.3.24, "Flow-Accelerated Corrosion," states that this program manages the loss of material aging effect due to flow-accelerated corrosion, and is based on the guidelines of NSAC-202L-R2. However, NSAC-202L-R2, states that systems can be susceptible to damage from other corrosion or degradation mechanisms, such as cavitation erosion, liquid impingement erosion, as well as others, and specifically states these mechanisms are not part of a flow accelerated corrosion program and should be evaluated separately.

Issue

The DAEC AMP Basis Document, LRAP-M017, Revision 2, "Flow-Accelerated Corrosion," Attachment 7.1, "Equipment and Internal Aging Effects Managed by Flow-Accelerated Corrosion Program," indicates that this program is also used to manage the aging effect "loss of material" due to both flow accelerated corrosion and erosion. Although the LRA program description clearly addresses flow accelerated corrosion, erosion is not discussed in any manner. In addition, the AMP Basis Document does not address the loss of material due to erosion in any of the ten program elements.

Request

Clarify the information in the LRA to indicate that the Flow-Accelerated Corrosion program will also be used to manage the aging effect of loss of material due to erosion, and discuss any consequent changes to the program elements within the Program Basis Document, LRAPM017, Revision 2.

DAEC Response to RAI B.3.24-01

The DAEC Flow-Accelerated Corrosion Program addresses erosion based on site specific operating experience. Attachment 7.1 of the program basis document identifies components that have experienced erosion. The text of the program basis document is being revised to specifically indicate that the program includes follow-up activities for identified erosion.

In LRA Section B.3.24, Flow-Accelerated Corrosion Program, at the end of Subsection B.3.24.1, Program Description, on page B-50, the following statement is added:

> The Flow-Accelerated Corrosion program manages loss of material due to erosion based on site-specific operating experience.

RAI B.3.24-02

Background

LRA Section B.3.24.5, "Operating Experience," states that the flow accelerated corrosion program has verified that actual wear was less than or equal to predicted wear.

Issue

The inspection results from refueling outage 20 indicated that there were several areas where the measured wear rate was higher than the predicted wear rate. In some cases, the measured wear rate was more than 2.5 times higher than predicted wear rate.

Request

Reconcile the apparent discrepancy between the statement made in the LRA and the latest refueling outage information relative to actual wear being less than predicted wear.

DAEC Response to RAI B.3.24-02

Flow Accelerated Corrosion inspection results from refueling outage 20 do include some cases where the measured wear rates were higher than the predicted wear rates. The statement in section B.3.24.5,"Operating Experience" stating that actual wear was less than or equal to predicted wear was incorrect.

Accordingly, in LRA Section B.3.24.5, Operating Experience, on the top of page B-51, the second sentence is revised to read as follows:

> The program has identified susceptible locations, performed baseline thickness measurements, predicted wear (wall thinning), and verified actual wear measurements against predicted wear values.

RAI B.3.24-03

Background

NUREG-1800 discusses the FSAR supplement for flow-accelerated corrosion program, and notes that the program consists of conducting appropriate analysis and baseline inspection.

Issue

LRA, Appendix A, "Duane Arnold UFSAR Supplement," Section 18.1.24, states that the program includes performance of limited baseline inspections.

Request

Clarify the extent that baseline inspections are limited and address the bases for the limitations of the baseline inspections.

DAEC Response to RAI B.3.24-03

The baseline inspections performed under the DAEC Flow-Accelerated Corrosion program meet the guidance described in the EPRI Guidelines in NSAC-202L-R2. The use of the term "limited" when describing the baseline inspections resulted from an attempt to closely match the wording of the program description in NUREG-1801 and did not indicate that the DAEC program inspections differed from those required by NUREG-1801.

In LRA Appendix A, Section 18.1.24, Flow-Accelerated Corrosion Program, in the second complete sentence on page A-11, the word limited is deleted. This sentence now reads as follows:

> Included in the program are: (a) an analysis to determine flow-accelerated corrosion susceptible lines; (b) performance of baseline inspections; (c) follow-up inspections to confirm the predictions; and (d) repairing or replacing components, as necessary.

RAI B.3.25-1

Background

NRC Information Notice 2009-02, "Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance," indicates that No. 2 diesel fuel could contain up to a 5 percent biodiesel fuel (B5) blend without labeling the blend in accordance with ASTM D 975-08a, "Standard Specification for Diesel Fuel Oils".

Issue

Biodiesel B5 blend 1) can have a cleaning effect that can increase sediment that could plug filters, 2) could form "dirty water" which leads to algae growth, 3) is biodegradable such that long term storage is not recommended and 4) can be more susceptible to gel creation in the presence of brass, bronze and copper fittings, piping and tanks. These effects could lead to plant-specific operating experience outside the bounds of industry operating experience.

Request

Is biodiesel fuel B5 blend used or will be used at Duane Arnold Energy Center (DAEC)? If so, has there been operating experience that indicates an increase in sediment, water formation, or gel formation? What actions have been taken to minimize the effects of using B5? If not, what method(s) are being used to assure that biodiesel fuel is not inadvertently being introduced into DEAC fuel tanks?

DAEC Response to RAI B.3.25-1

Biodiesel fuel is not used and will not be used at DAEC in the future. Currently the purchase orders for diesel fuel intended for use in the Standby Diesel Generators specify that the fuel may not contain biodiesel. The plant chemistry procedure for testing diesel fuel oil on delivery verifies that no biodiesel is present in the fuel sample. However, an enhancement will be incorporated into the LRA to assure that the purchase orders and sampling procedures for diesel fuel intended for use in the diesel fire pump specify that no biodiesel fuel is to be introduced to this storage tank as well.

In LRA Section B.3.25, Fuel Oil Chemistry Program, in Subsection B.3.25.4, Enhancements to Duane Arnold Program, on page B-53, an additional enhancement is added to read as follows:

- Enhance the program to require that the purchase orders and sampling procedures for diesel fuel delivered to and stored in the Diesel Fire Pump Fuel Oil Day Tank (1T089) prohibit the delivery and use of biodiesel fuel.

To reflect this additional enhancement, Commitment number 15 in LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is revised to read as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
15.	Fuel Oil Chemistry Program	Enhance procedures to require sampling and testing of new fuel oil delivered to the diesel fire pump day tank; and to require that purchase orders and sampling procedures for diesel fuel delivered to and stored in the diesel fire pump day tank prohibit the delivery and use of biodiesel fuel.	18.1.25	Prior to the period of extended operation

RAI B.3.25-2

Background

In the Fuel Oil Chemistry Program Basis Document, LRAP-M030, element 2, preventive actions, it is stated that the DEAC does not use fuel additives of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. GALL AMP XI.M30, element 3, "parameters monitored/inspected recommends monitoring for microbiological organisms.

Issue

However, it is not stated in the LRA if and how biological activity is monitored at DAEC.

Request

How is the presence of microbiological organisms monitored in fuel tanks at DAEC? What corrective action will be taken if microbiological organisms are determined to be present in diesel fuel oil at DAEC?

DAEC Response to RAI B.3.25-2

Microbiological organisms would normally only be expected with water layers in the fuel oil. Significant microbiological activity would be expected to reveal itself with increasing particulates in the fuel oil.

Microbiological organisms are identified as part of the monthly particulate (water/sediment) testing of the 1T-37A and 1T-37B SBDG Fuel Oil Day Tanks and the 1T-34 and 1T-35 fuel oil storage tanks. One of the enhancements identified for the Fuel Oil Monitoring Program in LRA Section B.3.25.4 is to require particulate testing of fuel oil samples from the Diesel Fire Pump day tank 1T089.

If microbiological organisms are identified as part of the particulate analysis, the issue would be entered into the Corrective Action Program and actions will be taken as identified during the corrective action evaluation. The Technical Specification surveillance test procedures for fuel oil prescribe that if any values are outside of procedural limits, immediately initiate actions to restore parameters within limits. Actions may include cleaning the fuel oil by recirculating the oil through a cleanup system.

RAI B.3.25-3

Background

In the Fuel Oil Chemistry Program Basis Document, LRAP-M030, element 4, Detection of Aging Effects, it is stated that there are no equipment specific procedures required to validate the quality of the fuel oil in the diesel driven air start air compressor fuel oil tanks 1T-477 and 1T-478. In addition, it was also stated that these tanks are not subjected to periodic cleaning and visual inspection, or UT because the tanks are small, have high fuel turnover and general inspections indicate no degradation, and as such this is not considered an exception to the GALL.

Issue

The staff does not agree that inscope fuel tanks, that are not subjected to any of the elements recommended in the GALL AMP XI.30, are not an exception to GALL AMP XI.30. The staff noted that since there is a high turnover of fuel in the diesel driven air start air compressor fuel oil tanks from a source where contaminants are controlled, loss of material is not expected for these tanks or would be occurring so slowly such that the intended function of the tanks will be compromised during the period of extended operation.

Request

To verify loss of material is not a concern for the driven air start air compressor fuel oil tanks, the staff requests further justification for not performing any preventive/mitigative activities and interior visual or one-time UT examinations to confirm degradation has not occurred in diesel driven air start air compressor fuel oil tanks 1T-477 and 1T-478.

DAEC Response to RAI B.3.25-3

A clarification of the information provided in the question background is necessary. The Fuel Oil Chemistry Basis Document, LRAP-M030, Section 3.42, Detection of Aging Effects, does not state that the tanks 1T-477 and 1T-478 are not subject to periodic cleaning and visual inspection. It states only that, based on the discussion provided, ultrasonic inspections of the tank bottom are not justified. Section 3.2.5 of LRAP-M030 and LRA Section B.3.25.4 list the program enhancements, one of which is to assure that the frequencies for the periodic draining or cleaning of the diesel fuel oil day tanks, diesel fire pump day tanks and diesel driven air start air compressor fuel oil tanks are on a schedule of every ten years. This enhancement is Commitment 16 of LRA Appendix A, Section 18.1.4, Table A-1 Duane Arnold License Renewal Commitments.

RAI B.3.25-4

Background

The LRA provides an enhancement to the Fuel Oil Chemistry Program, element 2, Preventive Action, to expand the existing program preventive action element to add periodic draining or cleaning of the diesel fuel oil day tanks, diesel fire pump day tank and diesel driven air start air compressor fuel oil tanks on a schedule of every ten years.

Issue

However, GALL AMP XI.M30, element 2 "preventive action" states that periodic cleaning of a tank allows removal of sediment and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time.

Request

Provide justification for not performing both draining and cleaning of these tanks. Additionally, GALL AMP XI.M30, element 4 "detection of aging effects" recommends visual inspection of tanks that are drained and cleaned to detect potential degradation. Will diesel fuel oil day tanks, diesel fire pump day tank and diesel driven air start air compressor fuel oil tanks be subjected to visual inspection after they are drained and cleaned on a schedule of every ten years?

DAEC Response to RAI B.3.25-4

LRA Section B.3.25, Fuel Oil Chemistry Program, Subsection B.3.25.4 on page B-53, fourth bullet, is revised to read as follows:

> Enhance the Program to assure that the frequencies for the periodic draining, cleaning and visual inspection of the diesel fuel oil day tanks, diesel fire pump day tank and diesel driven air start air compressor fuel oil tanks are on a schedule of every ten years.

To reflect this wording change, Commitment number 16 in LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is revised to read as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
16.	Fuel Oil Chemistry Program	Enhance procedures to perform periodic (10 year) draining, cleaning and visual inspection of the diesel fuel oil day tanks, diesel fire pump day tank, and diesel driven air start air compressor fuel oil tanks.	18.1.25	Prior to the period of extended operation

RAI B.3.25-5

Background

The operating experience element of the LRA indicates that the main diesel fuel oil storage tank was drained, cleaned and ultrasonically inspected in April 2001.

Issue

GALL AMP XI.M30 recommends visual examination after draining and cleaning.

Request

Was visual inspection performed at that time and will visual inspection be performed after draining and cleaning in the future?

DAEC Response to RAI B.3.25-5

The work order package indicated that visual inspection of the tank revealed the tank to be in good condition with no observed degradation. Visual inspections will be performed after draining and cleaning in the future.

RAI B.3.26-1

Background

LR-SRP Table 3.6.2, "FSAR Supplement for Aging Management of Electrical and Instrumentation and Control System," states that a fuse holders within the scope of license renewal will be tested at least once every 10 years and the first test for license renewal should be completed before the period of extended operation. LRA Appendix A, Table A-1, "Duane Arnold License Renewal Commitments," Item 18 specifies the establishment of the fuse holder program prior to the period of extended operation.

Issue

LRA Section B.3.26 states that the program is consistent with GALL AMP XI.E5. However, LRA Appendix A, "Duane Arnold UFSAR Supplement," Section 18.1.26, "Fuse Holders Program," does not include a frequency of inspection (every 10 years). LRA Appendix A, Table A-1, "Duane Arnold License Renewal Commitments," Item 18 is not consistent with the LR SRP.

Request

Provide a discussion as to why LRA Appendix A does not need to be consistent with LR SRP Table 3.6.2 with regard to including an inspection frequency.

DAEC Response to RAI B.3.26-1

In LRA Appendix A, Section 18.1.26, Fuse Holder Program, the following paragraph is inserted as a new third paragraph.

> Fuse holders within the scope of license renewal will be inspected at least once every 10 years. The first inspection is to be completed before the period of extended operation.

To reflect this wording change, Commitment number 18 in LRA Appendix A, Section 18.4, Table A-1 Duane Arnold License Renewal Commitments, is revised to read as follows:

Item No.	System, Component or Program	Commitment	Section	Schedule
18.	Fuse Holders Program	Implement a Fuse Holders Program and complete the first test prior to the period of extended operation.	18.1.26	Prior to the period of extended operation

RAI B.3.26-2

Background

GALL AMP XI.E5 states that the fuse holder AMP needs to account for the following aging stressors if applicable: fatigue, mechanical stress, vibration, chemical contamination, and corrosion. XI.E5 element 3 states that the monitoring includes thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling, or electrical transients, mechanical fatigue caused by frequent removal/replacement of the fuse or vibration, chemical contamination, corrosion, and oxidation.

Issue

LRA AMP B.3.26 does not discuss as to why some of the aging stressors identified in GALL XI.E5 are not applicable to LRA AMP B.3.26.

Request

Explain why the additional aging stressors identified by GALL AMP XI.E5 are not applicable to Duane Arnold for LRA AMP B.3.26 or LRA Section 3.6.

DAEC Response to RAI B.3.26-2

In LRA Section B.3.26, Fuse Holders Program, Subsections B.3.26.2 and B.3.26.3 on page B-54 are revised as follows:

B.3.26.2 NUREG-1801 CONSISTENCY

The program is consistent with nine of the elements of NUREG XI.E5. Exception is taken to "Parameters Monitored/Inspected." This exception is listed below.

B.3.26.3 EXCEPTIONS TO NUREG-1801

The program takes exception to the guidance as stated in NUREG-1801 XI.E5. This exception affects the following element of NUREG-1801 XI.E5:

- Parameters Monitored or Inspected

  The program takes exception to the following aging mechanisms listed in NUREG-1801 XI.E5:

Electrical Transients

The only electrical transients significant enough to cause fatigue are phase to ground, phase to phase or three phase faults. These electrical transients are events and not aging mechanisms.

Vibration

Fuse holders are installed in panels. Panels are not sources of vibration and are installed to minimize vibrations being transmitted to equipment in the panel.

Chemical Contamination

Plant design and installation practices provide appropriate protection for fuse holders from chemical contamination by requiring fuses to be installed in enclosures. Boric acid chemical contamination is not a concern for boiling water reactors.

Corrosion

Plant installation and maintenance practices provide appropriate protection for fuse holders from moisture intrusion (such as in enclosures). The location of fuse holders was reviewed to identify fuse holders installed outside of an active device, junction box, or similar type enclosures (i.e., unprotected environment). This review identified no unprotected fuses. Boric acid chemical contamination is not a concern for boiling water reactors. Panels protect the fuse holders from the causes of corrosion (moisture and chemicals).

Oxidation

Oxidation is not an aging mechanism unless there are other chemicals or moisture present. The panels protect the fuse holder from chemicals and moisture.

To reflect these changes, following additional LRA changes are made.

In LRA Table 3.6-2 Summary of Aging Management Review Results Electrical and instrumentation and Control Commodity Groups on page 3.6-16, in the line item for Fuse holders (metallic clamp), the notes entry is changed from A to B.

In LRA Appendix A, Section 18.1.26, Fuse Holders Program, on page A-11, the last sentence is revised to read as follows:

This program is consistent with the ten elements of NUREG-1801 XI.E5 with the following exception:

- The program takes exception to the following aging mechanisms listed in NUREG-1801 XI.E5:

  Electrical Transients
  The only electrical transients significant enough to cause fatigue are phase to ground, phase to phase or three phase faults. These electrical transients are events and not aging mechanisms.

  Vibration
  Fuse holders are installed in panels. Panels are not sources of vibration and are installed to minimize vibrations being transmitted to equipment in the panel.

  Chemical Contamination
  Plant design and installation practices provide appropriate protection for fuse holders from chemical contamination by requiring fuses to be installed in enclosures. Boric acid chemical contamination is not a concern for boiling water reactors.

  Corrosion
  Plant installation and maintenance practices provide appropriate protection for fuse holders from moisture intrusion (such as in enclosures). The location of fuse holders was reviewed to identify fuse holders installed outside of an active device, junction box, or similar type enclosures (i.e., unprotected environment). This review identified no unprotected fuses. Boric acid chemical contamination is not a concern for boiling water reactors. Panels protect the fuse holders from the causes of corrosion (moisture and chemicals).

  Oxidation
  Oxidation is not an aging mechanism unless there are other chemicals or moisture present. The panels protect the fuse holder from chemicals and moisture.

In LRA Table B.2.2-1 on page B-7, for line item XI.E5 - Fuse Holders, the NUREG-1801 Comparison entry is revised to read as follows:

Consistent with NUREG-1801 with one exception

RAI B.3.26-3

Background

GALL AMP XI.E5 program element 3 states that the monitoring includes thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling, or electrical transients, mechanical fatigue caused by frequent removal/replacement of the fuse or vibration, chemical contamination, corrosion, and oxidation.

Issue

Duane Arnold report LRAM-EFH, "Aging Management Review for Fuse Holders," Section 2.4, "Operating Environments and Exposures," Item 2.4.1, Environmental Conditions," states that all fuse holders are located inside a cabinet, panel, or other electrical enclosure to protect the fuse holder from moisture. Item 2.4.1, also states that fuse holders will be exposed to ambient temperature conditions inside the electrical enclosure. However, LRAM-EFH Section 5.1 under "Corrosion" states that fuse holders are protected by their location within a controlled environment.

Request

Provide a discussion as to why there is a difference between identified fuse holder environmental conditions within LRAM-EFH.

DAEC Response to RAI B.3.26-3

There was no intent to have two different environments. The sentence, "Fuse Holders are protected by their location within a controlled environment," has been deleted from the report.

RAI B.3.27-1

Background

Gall AMP XI.E3 under program element, "Preventive Actions" states that periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes, and draining water, as needed. The applicant's AMP Basis Document LRAP-E003, "Inaccessible Medium-Voltage Cables," aging management attribute 3.2, 'Preventive Actions," Section 3.2.2, DAEC Program Preventive Actions," states that the DAEC program consists of periodically inspecting the manholes for moisture and ensuring that the sump pumps in the manholes are operational. Section 3.2.2 further states that the sump pumps will drain the water as necessary and the sump pumps will keep the water below the level of the cables during normal seasonal conditions.

Issue

From the staff review of provided duct bank documentation and selected walkdowns, the staff notes that it is not clear that all manholes associated with GALL AMP XI.E3 medium voltage cables are equipped with sump pumps and associated alarms such that the operation of the sump pumps provides consistency with GALL AMP XI.E3.

Request

Provide a discussion that confirms that the Preventive Actions as stated in LRAP-E003 are consistent with the GALL AMP XI.E3 program element.

DAEC Response to RAI B.3.27-1

The program basis document has been clarified to read:

> The DAEC program consists of periodically inspecting the manholes for moisture. The periodic inspection will be either an inspection of the manhole for water or verifying operation of the sump pump (for those manholes with sump pumps installed). Table 7.3 lists the manholes with sump pumps installed.

Table 7.3 has been revised to read:

Table 7.3 List of Manholes containing in-scope medium voltage cables		
1MH109	1MH113*	2MH209*
1MH110	2MH207	2MH210*
1MH111*	2MH208	2MH211*
1MH112*	MH106*	MH107*

* - Manhole has sump pump installed.

RAI B.3.27-2

Background

GALL AMP XI.E3 program element 3, Parameters Monitored/Inspected states that the specific type of test will be determined prior to the initial test, is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. The applicant's AMP Basis Document LRAP-E003 Section 2.0, Description of AMP states that the testing methodology currently used is a resistance test (meggar). LRAP-E003, Section 3.3, Parameters Monitored or Inspected also states that the testing methodology currently used is an insulation resistance test (meggar). The Acceptance Criteria stated in Section 3.6 of LRAP-E003 is also based on the above specified testing.

Issue

The applicant's basis document is not consistent with GALL AMP XI.E3 program element 3 and 6.

Request

Explain how program elements 3 and 6 as described in the basis document are consistent with associated GALL AMP XI.E3 program elements.

DAEC Response to RAI B.3.27-2

The program basis document discussion of element 3 has been revised to incorporate the following:

> The commercially available test methods will be reviewed prior to performing each test to see if a better test exists. The best commercially available test method will be used.

The program basis document discussion of element 6 has been revised to incorporate the following:

> Acceptance criteria will be defined in the applicable maintenance procedure for the test.

RAI B.3.27-3

Background

GALL AMP XI.E3, Program Element 1, Scope of Program, states that significant moisture is defined as periodic exposures to moisture that last less than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant.

The applicant's aging management report LRAM-ECAB states in Section 5.1 that one of the conditions needed for water treeing to occur is the presence of continuous (long-term) moisture. The applicant states cables in conduit embedded in the lowest floor of the building, direct buried cables, and cables in buried duct are assumed to be exposed to long-term moisture.

Applicant basis document LRAP-E003 includes the cables subject to long-term moisture are cables that are in a duct bank, embedded conduit (building base mat only), or direct buried.

LRA AMP B.3.27 states that the program includes medium voltage cables that support a license renewal function, are subject to submergence and are energized a significant portion of their life.

Issue

The time frame for significant moisture/long-term moisture/submergence is not defined in the LRA or the associated basis document.

Request

Explain how AMP B.3.27, LRAM-ECAB and LRAP-E003 are consistent as stated in the LRA with the definition of significant moisture as stated in GALL AMP XI.E3, Program Element 1, "Scope of Program."

DAEC Response to RAI B.3.27-3

The program basis document description of the scope of program has been revised to replace the term "long term moisture" with the term "significant moisture." This section of the basis document is now consistent with NUREG-1801 XI.E3 AMP.

In LRA Section B.3.27, Inaccessible Medium Voltage Cables Program, in Subsection B.3.27.1 Program Description, on page B-55, the second paragraph is revised to read as follows:

> The program includes medium voltage cables that support a license renewal intended function, are susceptible to significant moisture as defined in NUREG-1801 XI.E3, and are energized a significant portion of their life.

RAI B.3.27-4

Background

GALL AMP XI.E3, Program Element 1, Scope of Program states that the program applies to inaccessible medium-voltage cables (2KV – 35KV) within the scope of license renewal that are exposed to significant moisture simultaneously with significant voltage.

The applicant's basis document LRAP-E003 Table 7.2 lists all medium voltage cables and their applicability to LRA AMP B.3.27. Cable X00403D is listed as medium voltage, having a license renewal function, energized more than 25 percent of the time and routed as embedded/duct bank and therefore meeting the conditions for scoping for license renewal per 10 CFR 54.4.

Issue

The scope of the applicant's inaccessible cables program is not consistent with the scope associated with GALL AMP XI.E3 program element.

Request

Provide a discussion including manufacturer's documentation that cable X00403D is designed for submerged service to justify its exclusion from the scope of license renewal.

DAEC Response to RAI B.3.27-4

Based on industry information and industry standards, paper insulated lead covered (PILC) cable is designed for submergence/submarine service. Cable X00403-D is a PILC cable and is, therefore, designed for submergence/submarine service. However, Duane Arnold's record system does not contain any records for this cable since it was installed as part of the switchyard and not as part of the power plant. The manufacturer's name and part number are not visible on the exposed lengths of the cable (only about 6 inches at each end is exposed). As a result, manufacturer's documentation is not available.

Therefore, cable X00403-D has been added to the scope of the Inaccessible Medium Voltage Cable Aging Management Program.

RAI B.3.27-5

Background

Gall AMP XI.E3, Program Element 4, Detection of Aging Effects states that the first tests for license renewal are to be completed before the period of extended operation. GALL AMP XI.E3 also states that the first inspection for license renewal is to be completed before the period of extended operation. The applicant's basis document LRAP-E003 Section 3.4, Detection of Aging Effects states that this is an existing testing activity and therefore the first test has already been performed.

Issue

The implementation schedule (this test has already been performed) is not consistent with the GALL AMP XI.E3 (prior to the period of extended operation).

Request

Please explain how the schedule specified under LRAP-E003, Detection of Aging Effects meets the implementation schedule in GALL AMP XI.E3.

DAEC Response to RAI B.3.27-5

The statements about the first test having already been performed have been removed from the program basis document to make it consistent with NUREG-1801 XI.E3.

RAI B.3.27-6

Background

GALL AMP XI.E3 states that significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time.

The LRA UFSAR supplement states that medium voltage cables energized a significant portion of their life are in-scope. The LRA AMP B.3.27 also states that the program includes medium voltage cables that are energized a significant portion of their life. The applicant's basis document LRAP-E003 states that continuously energized is defined as the feeder breaker being closed greater than 75 percent of the time. The applicant's aging management report LRAM-ECAB states that continuously energized means energized greater than 25 percent of the time.

Issue

LRA UFSAR supplement, basis document LRAP-E003, and LRA AMP B.3.27 are inconsistent with LR SRP Table 3.6-2, "FSAR Supplement for Aging Management of Electrical and Instrumentation and Control System," and GALL AMP XI.E1 which states that significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time.

Request

Explain how LRA UFSAR supplement, basis document LRAP-E003, and LRA AMP B.3.27 are consistent with LR SRP Table 3.6-2, "FSAR Supplement for Aging Management of Electrical and Instrumentation and Control System," and GALL AMP XI.E3 which state that significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time.

DAEC Response to RAI B.3.27-6

This difference between the program basis document and the other documents was a typographical error. The intent was to be consistent with NUREG-1801 XI.E3. The program basis document has been corrected to be consistent with NUREG-1801 XI.E3.

RAI B.3.28-1

Background

The DAEC LRA Section (AMP) B3.36, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, commits to consistency with the GALL Report AMP XI.M33 with no exceptions or enhancements. The DAEC AMP Basis Document "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components of Materials Program," LRAP-M038, Revision 3, 03/31/09, quotes the GALL Report XI.M33 for the AMP element 5, Monitoring and Trending, and briefly describes the corresponding DAEC AMP elements.

Issue

GALL Report AMP XI.M33, Element 5 states, in part, that "Maintenance and surveillance activities provide for monitoring and trending of aging degradation. Inspection intervals are dependent on component material and environment, and take into consideration industry and plant-specific operating experience." For this AMP, the DAEC LRA and LRAP-M038 do not specifically commit to trending of aging degradation, having inspection intervals dependent on component material and environment, and consideration of industry operating experience.

Request

For AMP B3.36 Element 5, Monitoring and Trending, provide specific commitments to trending of aging degradation, having inspection intervals dependent on component material and environment, and consideration of industry operating experience, or provide the technical basis for this AMP Element's acceptability and consistency with the GALL Report AMP XI.M33.

DAEC Response to RAI B.3.28-1

The element 5, Monitoring and Trending, discussion in the DAEC program basis document for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program has been revised to include inspection intervals dependent on component material and environment, and to take into consideration industry and plant-specific operating experience. In addition, a requirement was added to trend any aging degradation that has been identified.

RAI B.3.30-1

Background

The Lubricating Oil Analysis Program is to ensure the oil environment in the mechanical systems is maintained to the required quality. This includes the integrity of the incoming as well as the in-service lubricating oil is free of contaminants. To this end GALL XI.M39 calls for a number of parameters to be monitored/inspected, through various tests. For components with periodic oil changes these include tests to identify particle count and water in the lubricating oil. For components that do not have regular oil changes tests also for viscosity, neutralization number, flash point are to be performed. These parameters are monitored to verify the suitability of oil for continued use. In addition, analytical ferrography and elemental analysis are also to be performed to identify wear particles.

Issue

The applicant in the LRA B.3.30.3 states there no exceptions to the ten elements of the GALL XI.M39. In LRAP-M039, DAEC Lubricating Analysis Program Basis Document, paragraph 3.3.2, the applicant maintains the DAEC parameters monitored or inspected are identified as listed in the GALL. In paragraph 3.6.2 of the same document, however, the applicant does not list the flash point as a test to be performed.

Request

1. Justify the deletion of the flash point test is not an exception to GALL.
2. Are there any other tests that are or could be performed to verify the suitability of oil for continued use?

DAEC Response to RAI B.3.30-1

Part 1

DAEC did not delete flash point testing. Flash point testing is performed as required by the DAEC Lubrication Program Manual and ASTM D6224-98. DAEC utilizes ASTM D6224-98, "Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment," for initial detection and utilization of flash point testing.

For clarity, flash point has been added as a test parameter in the program basis document table listing the parameters monitored for the various components subject to the Lubricating Oil Analysis Program.

In summary, DAEC maintains the DAEC parameters monitored or inspected as identified in NUREG-1801, and will perform flash point testing if applicable. Therefore, this is not an exception to the GALL.

Part 2

There are other tests available. However, DAEC performs the tests recommended by ASTM-D6224-98, "Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment." This practice covers the requirements for the effective monitoring of mineral oil and phosphate ester fluid lubricating oils in service auxiliary (non turbine) equipment used for power generation. Auxiliary equipment covered includes gears, hydraulic systems, diesel engines, pumps, compressors, and electrohydraulic control (EHC) systems. The standard includes sampling and testing schedules and recommended action steps, as well as information on how oils degrade.

DAEC's Oil Analysis Program administers the following types of standard oil analysis tests for lubricants used: Particle counts, Viscosity, Glycol contamination, Water contamination, Solids, Spectrochemical Analysis for additives, wear metals, dirt/sand, and, where applicable, Total Acid Number and flash point.

Therefore, while there may be other tests that can be performed, the DAEC Lubricating Oil Program as currently designed provides adequate testing to verify the suitability of oil for continued use.

RAI B.3.30-2

Background

The GALL, XI.M39 Lubricating Oil Analysis Program in program element #3, identifies specific parameters to be monitored or inspected. For example, these range from viscosity to neutralization number, flash point, particle count, etc. In program element #1, Scope of Program, the GALL recommends to obtain samples from lubricated oil components periodically.

Issue

In program element #3, of the LRA (B.3.30.4) the applicant defines an enhancement to that element. The applicant will enhance the program element by adding a Diesel Fire Pump 1P-049 to this element. In aging management scope of activities the LRA "should include the specific ... components" subject to license renewal.

Request

Justify why the pump, and other components are not listed in the scope of the program.

DAEC Response to RAI B.3.30-2

Component types crediting the Lubricating Oil Analysis Program for aging management are listed in the 3.x.2 tables of the LRA. A listing of individual components by identification numbers is not normally included in the scope section of program descriptions. This is consistent with the NRC-endorsed standard, NEI 95-10, Industry Guideline For Implementing The Requirements of 10 CFR Part 54-The License Renewal Rule.

RAI B.3.32-1

Background

GALL AMP XI.M32, element 4 "detection of aging effects" states that the inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel following procedures consistent with the American Society of Mechanical Engineers (ASME) Code and 10 CFR Part 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern. Typically, the one time inspections should be performed as indicated in the table GALL AMP XI.M32.

Issue

The LRA B.3.32, one-time inspection (OTI) Program and the associated basis document do not provide criteria that will be used to select locations and sample size for OTI inspection nor the techniques to be used to detect the various aging mechanisms.

Request

Provide criteria that will be used to select locations and sample size for OTI inspection and the techniques to be used to detect the various aging mechanisms.

DAEC Response to RAI B.3.32-1

The following information provides a description of the sampling methodology currently planned for the One-Time Inspection Program.

METHODOLOGY

DAEC will employ a "smart sampling" approach to the One-Time Inspection Program. The One-Time Inspection Program will be based on the premise that inspection of those areas most susceptible to aging can be used to confirm performance in less susceptible areas without the need for further inspections.

The technical review will include establishing a listing of scoped components with material and environment combinations most susceptible to the identified aging effects/mechanisms. Plant P&ID's and other documents will be referred to for assistance in selecting the most susceptible areas, such as those areas that experience low flow or stagnant conditions.

Identification of Proposed Sample Size and Locations

As described in the GALL, there are a number of attributes to consider when identifying aging effect susceptibility including: materials of fabrication, fabrication process, environment, and operating characteristics. A review of available literature, project documents, recent plant inspection results, and results of other utility OTI Programs (as available) will be performed to identify those attributes most likely to cause the aging effects identified for components and assets in each sample group and the areas where these effects are likely to occur. The GALL notes that one-time inspections should be performed no sooner than 10 years prior to the period of extended operation.

A one-time inspection sample population and sample locations for each Sample Group will be prepared.

Sample Group 1: Fuel Oil

Sample Group 1 was established to confirm the effectiveness of the Fuel Oil Chemistry Program to manage the loss of material aging effect.

This sample group contains 85 components. The following material groups, aging effect(s), number of components and minimum sample size are present in this sample group:

Material Group	Aging Effect(s)	Number of Component(s)	Minimum Sample Size
Carbon Steel (CS) and Cast Iron (CI)	Loss of Material	CS – 76 CI – 6	CS – 5 CI - 1
Stainless Steel (SS)	Loss of Material	3	SS -1

The sample locations take into consideration low flow and stagnant areas which are most likely locations for pooling. These same areas are prone to contaminants that further support the possible presence of these aging mechanisms. The most common locations for contaminants and water are low points and chambers in valves or other components. Irregular surfaces and dissimilar metals are candidates for loss of material. This information is considered in selecting sample size and locations.

A smart sample of select components from each material group and component type is chosen for the inspection set. Inspections of these items can be coordinated with plant maintenance procedures to take advantage of scheduled work activities.

Sample Group 2: Lube Oil

Sample Group 2 was established to confirm the effectiveness of the Lubricating Oil Analysis Program to manage the loss of material and heat transfer degradation aging effects.

This sample group contains 567 components. The following material groups, aging effect(s), number of components and minimum sample size are present in this sample group:

Material Group	Aging Effect(s)	Number of Component(s)	Minimum Sample Size
Aluminum Alloy (AL)	Loss of Material	AL – 3	AL – 1
Carbon Steel (CS), and Cast Iron (CI)	Loss of Material	CS – 446 CI - 20	CS – 7 CI - 1
Copper Alloy (CA), includes Admiralty Brass	Loss of Material Heat Transfer Degradation	CA - 4	CA -1*
Stainless Steel (SS), includes CASS	Loss of Material	SS - 94	SS - 4

* Includes one surface sample for Heat Transfer Degradation

The sample locations take into consideration low flow and stagnant areas which are most likely locations for pooling. These same areas are prone to contaminants that further support the possible presence of these aging mechanisms. The most common locations for contaminants and water are low points and chambers in valves or other components. Irregular surfaces and dissimilar metals are candidates for loss of material. This information is considered in selecting sample size and locations.

A smart sample of select components from each material group and component type is chosen for the inspection set. Inspections of these items can be coordinated with plant maintenance procedures to take advantage of scheduled work activities.

Sample Group 3: Reactor Coolant and Sodium Pentaborate

Sample Group 3 was established to confirm the effectiveness of the Water Chemistry Program to manage the loss of material and cracking aging effects.

This sample group contains 689 components. The following material groups, aging effect(s), number of components and minimum sample size are present in this sample group:

Material Group	**Aging Effect(s)**	**Number of Component(s)**	**Minimum Sample Size**
Carbon Steel (CS) and Low Alloy Steel (LA)	Loss of Material	CS – 163 LA – 1	CS – 5 LA – 1
Nickel Alloy (Ni)	Loss of Material Cracking	Ni - 3	Ni -2
Stainless Steel (SS), includes CASS, Carbon Steel w/SS Cladding and Low Alloy Steel w/SS Cladding	Loss of Material Cracking	SS - 522	SS - 9

The sample locations take into consideration low flow and stagnant areas which are most likely locations for corrosion. These same areas are prone to contaminants that further support the possible presence of these aging mechanisms. The most common locations for contaminants are low points and chambers in valves or other components. Irregular surfaces and dissimilar metals are candidates for loss of material. Temperature is taken into consideration for cracking. This information is considered in selecting sample size and locations.

A smart sample of select components from each material group and component type is chosen for the inspection set. Inspections of these items can be coordinated with plant maintenance procedures to take advantage of scheduled work activities.

Sample Group 4: Steam and Treated Water

Sample Group 4 was established to confirm the effectiveness of the Water Chemistry Program to manage the loss of material, heat transfer degradation and cracking aging effects.

This sample group contains 7473 components. The following material groups, aging effect(s), number of components and minimum sample size are present in this sample group:

Material Group	**Aging Effect(s)**	**Number of Component(s)**	**Minimum Sample Size**
Copper Alloy (CA)	Loss of Material Heat Transfer Degradation	CA - 22	CA – 4
Carbon Steel (CS), Low Alloy Steel (LA) and Cast Iron (CI)	Loss of Material	CS – 3411 LA – 13 CI - 23	CS – 9 LA – 1 CI - 1
Stainless Steel (SS), includes CASS,	Loss of Material Heat Transfer Degradation Cracking	SS - 4004	SS – 9

The sample locations take into consideration low flow and stagnant areas which are most likely locations for corrosion. These same areas are prone to contaminants that further support the possible presence of these aging mechanisms. The most common locations for contaminants are low points and chambers in valves or other components. Irregular surfaces and dissimilar metals are candidates for loss of material. Temperature is taken into consideration for cracking. Material surface fouling affects heat transfer. This information is considered in selecting sample size and locations.

A smart sample of select components from each material group and component type is chosen for the inspection set. Inspections of these items can be coordinated with plant maintenance procedures to take advantage of scheduled work activities.

Aging Effects / Mechanisms and Inspection Methods for One-Time Inspection Program

Aging Effect	**Aging Mechanism**	**Parameter Monitored**	**Measurement Method**
Loss of Material	Crevice Corrosion	Wall Thickness	Visual (VT-1) and / or Volumetric (RT or UT)

Loss of Material	Galvanic Corrosion	Wall Thickness	Visual (VT-3) and /or Volumetric (RT or UT)
Loss of Material	General Corrosion	Wall Thickness	Visual (VT-3) and /or Volumetric (RT or UT)
Loss of Material	MIC	Wall Thickness	Visual (VT-3) and / or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Wall Thickness	Visual (VT-1) and /or Volumetric (RT or UT)
Loss of Heat Transfer	Fouling	Tube Fouling	Visual (VT-3) or Enhanced VT-1 for CASS
Cracking	SCC	Cracks	Enhanced Visual (VT-1) and / or Volumetric (RT or UT)

RAI B.3.32-2

Background

GALL AMP XI.M32, element 4 "detection of aging effects" states that with respect to inspection timing, the population of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function at any time during the period of extended operation.

Issue

It appears that all OTIs can not practically take place in the last RFO before entering the period of extended operation.

Request

Provide timing for the various inspections such that all inspections will be performed before entering the period of extended operation.

DAEC Response to RAI B.3.32-2

The DAEC License Renewal Project has assigned implementation coordinators tasked with the responsibility for reviewing on line and outage scheduled work activities for the purpose of identifying opportunities for component inspections to satisfy the License Renewal One-Time Inspection requirements. As discussed in the response to RAI B.3.32-1, a technical report has also been prepared to provide the methodology for sample selection strategies, general considerations, inspection methods and acceptance criteria. This document provides guidance for the selection process for the sample locations that will be credited for the License Renewal One-Time Inspections.

DAEC has two refueling outages scheduled prior to entering the period of extended operation in February of 2014. RFO 22 is scheduled for October 2010 and RFO23 is scheduled for October 2012.

DAEC plans to identify select components and incorporate the inspection requirements into the planning and scheduling process to ensure the required inspections are performed before entering the period of extended operation. DAEC will review the scope of each outage for opportunities for crediting an existing activity for one time inspections. DAEC recognizes that opportunistic inspections may not accommodate completing all of the required one time inspections in the available timeframe before extended period of operation. Therefore, DAEC plans to compare the selected samples with the opportunistic samples performed; for any remaining required inspections, dedicated work orders for one time inspections will be initiated, planned and scheduled accordingly to ensure the required inspections are completed prior to extended period of operation.

RAI B.3.32-3

Background

GALL AMP XI.M32, element 10 "operating experience" states that this program applies to potential aging effects for which there are currently no operating experience indicating the need for an AMP. Nevertheless, the elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice. The LRA states that the DAEC One-Time Inspection is a new program; therefore, there is no plant-specific program operating experience for program effectiveness.

Issue

Although there is no captured plant-specific operating experience (OE) related to this program because this program is yet to be developed, any OE resulting from maintenance etc. should be included for systems and components that will be subjected to OTI.

Request

Provide a summary of OE resulting from observations resulting from maintenance and corrective action activities.

DAEC Response to RAI B.3.32-3

DAEC performed 32 initial opportunistic inspections of components scoped for the One-Time Inspection Program that were scheduled for maintenance during the February 2009 Refuel Outage. These initial inspections performed during the last refueling outage identified no passive components with loss of material due to corrosion.

RAI B.3.33-1

Background

The applicant states that its LRA AMP Open Cycle Cooling Water System (B.3.33) is consistent with the GALL Report AMP, Open Cycle Cooling Water System (XI.M20). In its audit of program elements 2, 3 and 5 (preventive actions, parameters monitored or inspected and monitoring and trending), the staff identified a potential inconsistency between the LRA AMP and the GALL Report AMP.

Issue

Program element 2 of the GALL Report AMP, preventive actions, states that system components should be constructed of appropriate materials and be lined or coated to protect the underlying metal surfaces. Program elements 2, 3, and 5 of the LRA AMP state that open cycle cooling water piping is constructed from carbon steel, which is not lined or coated. Corrosion rates of lined piping exposed to open cycle cooling water are expected to be much lower than those experienced by unlined pipe. Since the GALL Report AMP is designed to manage the corrosion of lined pipe, it is not clear that the LRA AMP, which claims consistency with the GALL AMP, will adequately manage the aging of the unlined pipe. The inclusion of unlined pipe in the LRA AMP is considered to be an exception to the GALL AMP.

Request

Please commit to revise the LRA AMP to show the inclusion of unlined pipe as an exception. Additionally please justify why the proposed program is sufficient to manage the aging of unlined pipe.

DAEC Response to RAI B.3.33-1

LRA Changes

In LRA Section B.3.33, Open Cycle Cooling Water System Program, Subsection 3.33.2, NUREG-1801 Consistency, on page B-64, is revised to read as follows:

B.3.33.2 NUREG-1801 CONSISTENCY

This program is consistent with five of the ten elements of NUREG-1801 XI.M20. One exception is taken that affects "Scope of Program", "Preventive Actions", "Parameters Monitored or Inspected", "Detection of Aging Effects" and "Monitoring and Trending".

In LRA Section B.3.33, Open Cycle Cooling Water System Program, Subsection 3.33.3, Exceptions to NUREG-1801, on page B-65, is revised to read as follows:

B.3.33.3 EXCEPTIONS TO NUREG-1801

The DAEC program takes one exception to the guidance stated in NUREG-1801 XI.M20. This exception affects the following elements of NUREG-1801 XI.M20.

- Scope of Program
- Preventative Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending

DAEC OCCW components included within the scope of this program are constructed of appropriate materials that are not lined or coated; therefore, DAEC takes exception to the NUREG-1801 requirement for OCCW components which are constructed of appropriate materials to be lined or coated.

To reflect these changes, the following additional LRA changes are made.

LRA Appendix A, Section 18.1.33, Open Cycle Cooling Water System Program, on page A-14, is revised to read as follows:

18.1.33 OPEN CYCLE COOLING WATER SYSTEM PROGRAM

The Open Cycle Cooling Water System Program relies on implementation of NRC Generic Letter 89-13 to ensure that the effects of aging on the raw water systems are managed for the period of extended operation.

The OCCW program manages the aging effects in the following systems:

- Circulating Water System
- River Water Supply System
- Residual Heat Removal Service Water System
- Emergency Service Water System

This program is consistent with the ten elements of NUREG-1801 XI.M20 with one exception taken to the requirement for metal surfaces of underlying system components to be lined or coated. The DAEC open cycle cooling water (OCCW) piping included within the scope of this program is constructed of carbon steel that is not lined or coated. The original design of the DAEC piping for OCCW systems selected unlined/uncoated piping that is acceptable for the environment and intended functions of these piping systems.

In LRA Table B.2.2-1, Aging Management Program Correlation, on page B-9, in the line item for program XI.M20 - Open Cycle Cooling Water System, the NUREG-1801 Comparison entry is revised to read, "Consistent with NUREG-1801 with one exception."

To reflect the new exception in the Open Cycle Cooling Water System Program where that program is cited in the 3.x 2 tables, the associated Notes entries are changed from A to B or from C to D, as applicable. The affected tables are listed below:

Table 3.2.2-5 on pages 3.2-57, 3.2-58
Table 3.3.2-4 on pages 3.3-80, 3.3-81 through 3.3-83
Table 3.3.2-6 on pages 3.3-95, 3.3-96, 3.3-98
Table 3.3.2-10 on pages 3.3-123 through 3.3-127
Table 3.3.2-16 on pages 3.3-161 through 3.3-165
Table 3.3.2-23 on page 3.3-195
Table 3.3.2-25 on page 3.3-209 through 3.3-217
Table 3.3.2-27 on page 3.3-219
Table 3.3.2-29 on page 3.3-232 through 3.3-235, 3.3-238, 3.3-240, 3.3-248
Table 3.4.2-3 on page 3.4-45

Justification for use of Unlined Pipe

The DAEC original design specification specified unlined carbon steel material for the Open Cycle Cooling Water Systems. This is an appropriate material since DAEC raw water provides a non-aggressive environment.

The DAEC Open Cycle Cooling Water Program includes a variety of inspection and testing such as visual, Eddy Current and UT inspections on plant heat exchangers and piping. These activities are designed to detect degradation due to corrosion, MIC, biofouling, silt, debris, and scaling prior to loss of intended function.

DAEC performs periodic examinations on safety related and non safety related service water piping and raw water intake pits. The objective is to detect pipe wall thinning and internal blockage or growth from silting, corrosion or biological products. The primary purpose of the examinations is to ensure the integrity of the susceptible systems is maintained. Inspection methods include visual, ultrasonic (UT), and eddy current testing (ECT).

Plant operating experience supports the conclusion that the DAEC program is effective in managing the effects of aging for the OCCW systems.

RAI B.3.34-1

Background

GALL Report AMP XI.M3, "Reactor Head Closure Studs," element 4, Detection of Aging Effects, recommends surface and volumetric examination of studs when removed.

Issue

LRA B.3.34 states that the DAEC AMP is consistent with the GALL Report AMP and states that the AMP is an integral part of the DAEC Section XI Inservice Inspection Program. However, Attachment III of the DAEC Inservice Inspection Administrative Document, Table IWB-2500-1, Examination Category B-G-1, for Reactor Vessel closure head studs and nuts, under footnote 7, states that when bolts or studs are removed for examination, surface examination meeting the acceptance standards of IWB-3515 may be substituted for volumetric examination.

Request

Please justify why this is not considered an exception to the GALL Report AMP.

DAEC Response to RAI B.3.34-1

In LRA Section B.3.34, Reactor Head Studs Program, Subsection B.3.34.2 NUREG-1801 Consistency, is revised to read as follows:

B.3.34.2 NUREG-1801 CONSISTENCY

This program is consistent with nine of the ten elements of NUREG-1801 XI.M3. Exception is taken to "Detection of Aging Effects." This exception is listed below.

In LRA Section B.3.34, Reactor Head Studs Program, Subsection B.3.34.3, Exceptions to NUREG-1801, on page B-65, is revised to read as follows:

B.3.34.3 EXCEPTIONS TO NUREG-1801

This program takes exception to the guidance of NUREG-1801 XI.M3. This exception affects the following element of NUREG-1801 XI.M3

- Detection of Aging Effects

  NUREG-1801 XI.M3 states that both surface and volumetric inspections of studs are performed when removed. DAEC inspection of the reactor head closure studs program is performed in accordance with the applicable portions of ASME Section XI and 10 CFR 50.55a which do not necessarily require both inspections.

To reflect these changes, the following additional LRA changes are made.

In LRA Appendix A, Section 18.1.34, Reactor Head Closure Studs Program, on page A-14, is revised in its entirety to read as follows:

18.1.34 REACTOR HEAD CLOSURE STUDS PROGRAM

The Reactor Head Closure Studs Program is an integral part of the ASME Section XI Inservice Inspection Program. The program incorporates the appropriate Code edition and sections of ASME Section XI Subsection IWB. The program provides preventive measures to mitigate cracking. These measures include material selection, appropriate coatings, and lubrications which follow the guidelines of NRC Regulatory Guide 1.65.

This program takes exception to the NUREG-1801 XI.M3 requirement to perform surface and volumetric inspections of studs when removed. DAEC inspection of the reactor head closure studs program is performed in accordance with the applicable portions of ASME Section XI and 10 CFR 50.55a which do not necessarily require both inspections.

In LRA Table 3.1.2-1, Summary of Aging Management Review Results Nuclear Boiler, on page 3.1-64, for line item Top head enclosure studs and nuts with an Aging Effect Requiring Management of Cracking, the Notes entry is changed from A to B.

In LRA Table B.2.2-1 on page B-8, for program XI.M3 - Reactor Head Closure Studs, the NUREG-1801 Comparison entry is revised to read, "Consistent with NUREG-1801 with one exception."

RAI B.3.36-1

Background

The DAEC LRA Section (AMP) B3.36, Selective Leaching of Materials Program, commits to consistency with the GALL Report AMP XI.M33 with no exceptions or enhancements.

Issue

The DAEC AMP Basis Document Selective Leaching of Materials Program, LRAP-M033, Revision 3, 04/06/09, quotes the GALL Report XI.M33 wording for the AMP elements of Scope of Program, Parameters Monitored or Inspected, Detection of Aging Effects, and Acceptance Criteria, and briefly describes the corresponding DAEC AMP elements. Sufficient description is not provided to evaluate the acceptability of these AMP elements of Scope of Program.

Request

For AMP B.3.36, provide additional description of the basis, actions, support and specifics for the following elements:

A. Scope of Program
   1. Clarify the basis for the inspection population and sample size for the selected set of sample components for the one-time visual inspection and hardness measurements.
   2. Clarify that the AMP will evaluate external, as well as internal surfaces, where appropriate for the system or component.

B. Parameters Monitored or Inspected
   1. Provide description of the parameters to be monitored or inspected, including the methods or techniques to be used. Identify specifics of hardness measurements or other inspection techniques.

C. Detection of Aging Effects
   1. Clarify the basis for the inspection population and sample size for the selected set of sample components for the one-time visual inspection and hardness measurements.
   2. Clarify that the AMP will evaluate external, as well as internal surfaces, where appropriate, and that inspection or monitoring will adequately detect internal or external corrosion caused by selective leaching.
   3. Clarify what are considered acceptable "other mechanical tests."

D. Acceptance Criteria
   1. Identify and provide details of acceptance criteria for hardness or other mechanical inspection technique.
   2. Clarify what constitutes "identification of selective leaching," which would lead to further engineering evaluation and, if necessary a root cause analysis.

DAEC Response to RAI B.3.36-1

Part A1
The inspection population and sample size is based on the component type/material and their subjected environment. A minimum of one type of component/material type subjected to raw water, treated water or groundwater will be inspected to determine whether loss of material due to selective leaching is occurring and whether the extent of that material loss will affect the ability of the component sample to continue to perform its intended function during the period of extended operation.

Part A2
The component list in the Selective Leaching Program basis document was populated through the License Renewal Rule aging management review (AMR) process for evaluating systems, structures and components. The program basis document provides this list in two sections, Internal and External, for specifying the applicable environment-surface susceptibility for the selected component.

Part B1
Selective leaching occurs when one element of a solid alloy is removed by corrosion; the process is known as selective leaching, dealloying or dezincification. Parameters of selective leaching detection consist of recognizing the elementals of the corrosion. Indications of iron oxide coloration, rust, honeycomb like configurations, porous mass and degraded-weakened structure integrity of the corroded areas are examples for parameters of detection. DAEC will perform visual inspections and hardness testing for components that may be susceptible to selective leaching and assess their ability to perform the intended function during the period of extended operation. DAEC recognizes from operating experience, that other acceptable mechanical tests such as scraping or chipping the material surfaces are also available to observe if crumbling (unacceptable graphite structure removal) is occurring, which would be an indication of dealloying of the material. In addition, another mechanical test would be to impact areas of the component with a hammer to visually inspect the component integrity at the impacted surface area.

Part C1
The inspection population and sample size are based on the component type/material and their subjected environment. A minimum of one type of component/material type subjected to raw water, treated water or groundwater will be inspected to determine whether loss of material due to selective leaching is occurring and whether the extent of that material loss will affect the ability of the component sample to continue to perform its intended function during the period of extended operation.

Part C2
The component listing in the program basis document is broken into two sections, Internal and External, for specifying the applicable environment-surface susceptibility for the selected component. The program will select and inspect internal or external

surfaces as applicable to assure the inspections occur to adequately detect corrosion caused by selective leaching.

Part C3

DAEC recognizes from operating experience, that other acceptable mechanical tests such as scraping or chipping the material surfaces are also available to observe if crumbling (unacceptable graphite structure removal) is occurring, which would be an indication of dealloying of the material. In addition, another mechanical test would be to impact areas of the component with a hammer to visually inspect the components integrity at the impacted surface area.

EPRI is tasked with researching techniques that enables utilities to adequately detect internal or external corrosion caused by selective leaching with a credible technology. DAEC is actively monitoring the EPRI effort and will evaluate industry precedents for alternate techniques of determining if selective leaching is occurring.

Part D1

The acceptance criterion for a hardness test is to ensure the tested material has no compromised difference in hardness values from the published hardness value of the selected material.

The acceptance criterion for other mechanical tests such as scraping or chipping the material surfaces is to ensure no unacceptable graphite structure removal occurs during the test.

The acceptance criterion for impacting the material with a hammer is to visually ensure no degradation of the components structural integrity is observed at impact

Part D2

DAEC will perform visual inspections and hardness tests on selected components for determination if selective leaching is present. If selective leaching is suspected from the visual inspection or from the hardness test or other mechanical tests, corrective action processes will be initiated. The corrective action will trigger an engineering evaluation. This evaluation will typically consist of actions to determine the root cause of the identified issue. In addition, this action may determine if additional inspections or testing are required to confirm the identified failure mechanism.

RAI B.3.36-2

Background

The DAEC LRA Section (AMP) B3.36, Selective Leaching of Materials Program, commits to consistency with the GALL Report AMP XI.M33 with no exceptions or enhancements. The DAEC AMP Basis Document Selective Leaching of Materials Program, LRAP-M033, Revision 3, 04/06/09, quotes the GALL Report XI.M33 wording for the AMP element Operating Experience and briefly describes the corresponding DAEC AMP element.

Issue

The GALL Report AMP XI.M33, states that the elements that comprise these one-time inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. For AMP Element 10, Operating Experience, Industry has identified a number of instances attributed to selective leaching that may be applicable to the DAEC AMP. LRA Section (AMP) B.3.36 and LRAP-M033 address plant-specific operating experience, but they do not address other industry experience and practices for the staff to evaluate the acceptability of the AMP.

Request

For AMP B3.36, provide description of the industry operating experience searched and reviewed, and how it will be utilized for the basis and actions for implementation of the DAEC Selective Leaching AMP. Also provide specifics as to data bases, sources and documents searched, key search terms, and time periods.

DAEC Response to RAI B.3.36-2

NEI License Renewal Working Groups were established to allow utilities to share "best practices" by sharing operating experience (including inspection techniques and results) and commenting on implementation guidelines and work products. DAEC actively attends and participates within the NEI License Renewal working groups to gain insights for applicability and precedents for subject programs associated with requirements for extended power operation.

The operating experience collected for selective leaching at other nuclear stations revealed instances of selective leaching materials within certain material/environment combinations. This OE will be evaluated to determine if the identified selective leaching material/environment combinations are applicable to DAEC.

DAEC has performed an operating experience search of the corrective action database using keywords leaching and graphite. The search encompassed all corrective actions input to the database since the system was adopted in 1997. Corrective action reports associated with buried piping were identified and reviewed, including the results of the action taken for resolution.

The identified corrective action documents were reviewed for applicability to selective leaching. It was concluded that selective leaching was not the failure mechanism for any of the identified failures. The overall conclusion from the search is that there were no confirmed selective leaching failures at DAEC from 1997 to 2008.

RAI B.3.37-1

Background

The LRA Section B.3.37 states the Structures Monitoring Program is an existing program with an inspection frequency of five or ten years plus or minus one year depending on the environment.

Issue

The LRA states that the Structures Monitoring Program is consistent with GALL AMP XI.S6 and GALL AMP XI.S7. GALL AMP XI.S6 states that ACI 349.3R-96 provides an acceptable basis for inspection frequencies. ACI 349.3R-96 lists five or ten years as acceptable inspection frequencies, without mention of a possible one year extension. ACI 349R-96 further states that all safety-related structures should be visually inspected at intervals not to exceed 10 years. Furthermore, GALL AMP XI.S7 refers to Regulatory Guide 1.127, which states that visual inspections should not exceed five years for water-control structures.

Request

Provide justification for the five or ten year plus one year inspection interval discussed in the LRA. Explain how the frequency will provide assurance that any age-related degradation is detected at an early stage and that appropriate actions can be implemented.

DAEC Response to RAI B.3.37-1

ACI 349.3R-96 Chapter 6 states in part, "The frequency at which periodic evaluations are conducted within the evaluation procedure should be defined by the plant owner. ... In general, it is recommended that all safety-related structures be visually inspected at intervals not to exceed 10 years. In addition, the frequency of inspection for other components should follow in those in the table below. For consistency with ASME Boiler & Pressure Vessel Code (B&PVC), Section XI, the frequencies noted below are alternately expressed in terms of years and in-service inspection interval." The referenced table goes on to define inspection frequencies for specific components as "10 years (each ISI interval)" or "5 years (two per ISI interval)."

In ASME Section XI, Article IWA-2430, inspection intervals for both Program A and Program B permit each ten year inspection interval to be extended by as much as one year.

Therefore, the ten year interval specified in ACI 349.3R Chapter 6 is not defined as an absolute upper time limit. The language of both ACI 349 and ASME Code Section XI support the view that the ten year interval is considered the nominal length of the interval within which the inspections are completed. A number of areas to be inspected require access inside containment or other areas that are inaccessible during plant operation. The ability to extend a ten year interval by up to one year is important to DAEC or any nuclear plant to meet the practical needs of outage scheduling, since outages do not necessarily coincide with a ten year calendar interval.

Therefore, consistent with ACI 349.3R Chapter 6, the Structures Monitoring Program provides for two inspections to be accomplished in a 10 year period (at the 5+/-1 year frequency) for structures exposed to natural environment, structures inside primary containment, continuous fluid-exposed structures, and structures retaining fluid and pressure; and one inspection each 10+/-1 years will be completed (also stated in DAEC procedures as two each 20 years) for the below-grade structures and controlled interior environment structures. Individual inspections are actually conducted at times that coincide with accessibility of the structures to be inspected. Some inspections, then, are performed earlier than the nominal calendar timing, and some later, within the overall scheduling constraints discussed above.

As discussed in LRA Section B.3.37.5, operating experience supports the adequacy of these nominal inspection frequencies to ensure the integrity of affected structures. It should also be noted that, in accordance with ACI 349.3R, these nominal frequencies are subject to modification based on specific plant environments or observed degradation.

In summary, the inspection scheduling defined in the Structures Monitoring Program meets the intent of the ACI 349.3R-96 recommended inspection frequencies.

RAI B.3.37-2

Background

The LRA Section B.3.37 states that the Structures Monitoring Program will be enhanced to include periodic sampling of groundwater for chloride concentration, sulfate concentration, and pH on a ten year basis.

Issue

The GALL Report suggests periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations, to demonstrate that the below-grade environment remains non-aggressive. The GALL Report also states that ACI 349.3R-96 provides an acceptable basis for inspection frequencies. ACI 349.3R-96 lists five or ten years as acceptable inspection frequencies, depending on the structure and the environment. The staff believes the sampling for an aggressive groundwater environment should be at least as frequent as the inspection of structures located in an aggressive environment.

Request

1. Explain why the current ten year ground water monitoring frequency, as opposed to a five year frequency, is adequate to demonstrate a non-aggressive environment.
2. Provide the results of recent groundwater sampling.
3. Explain how the groundwater test samples provide a representative sample of the groundwater in contact with safety-related and important-to-safety embedded concrete foundations.
4. Explain how the enhancement will address seasonal variations.

DAEC Response to RAI B.3.37-2

The "Issue" states in part -"The staff believes the sampling for an aggressive groundwater environment should be at least as frequent as the inspection of structures located in an aggressive environment." DAEC does not concur that there is a relationship between the potential for physical degradation of a structure that is assessed through inspection, and any possible chemical changes in river or ground water. Significant changes in river or ground water chemistry that has been stable for many years are unlikely to occur. At DAEC, river water and groundwater sampling results do not indicate an aggressive environment that might warrant more frequent monitoring.

Part 1

River and groundwater data reviewed to date do not indicate any concerns regarding an aggressive groundwater environment. Current and future environmental conditions are not expected to change or to cause any change in groundwater to make water chemistry become aggressive. Current conditions are well below aggressive water chemistry thresholds for pH, chlorides, and sulfates, as presented in the LRA.

Inspections at DAEC indicate that structures are not exposed to aggressive environments, above grade or below grade.

Part 2

Recent groundwater sampling results are as follows:

Sample Description[1]	Shallow Wells					
	D111	D112	D113	D114	D115	D116
pH	6.60	6.87	7.06	6.87	7.20	6.79
Chloride (Cl) ppm	77	62	124	48	14	110
Sulfate (SO_4) ppm	349	470	112	270	14	92

[1]Samples from September 2007

Part 3

The groundwater samples listed above were taken from shallow wells. The aquifers of the shallow wells are replenished by direct precipitation, periodic flooding, and by river recharge.

The shallow well groundwater tests would be representative of the following:

- D111- south of the plant may be representative of groundwater affecting electrical manhole and duct banks
- D112 northeast of the Intake Structure would be representative of groundwater affecting the intake structure, electrical manhole and duct banks
- D113 northwest of the plant would be representative of groundwater affecting the power block
- D114 & D115 south of the plant near the Off-gas Stack would represent groundwater affecting the Off-gas Stack and electrical manholes and would also represent groundwater from the substation/switchyard
- D116 northeast of the plant would be representative of groundwater affecting the concrete cooling tower basins (with river/raw water on the inside of the basins)

Groundwater measurements indicate that flows in the upper aquifer are toward the river in a general southeasterly direction across the site. (Ref. DAEC UFSAR Section 2.4)

Part 4

DAEC has reviewed the potential for seasonal variations and concluded that there are no plausible mechanisms that would cause river water or groundwater chemistry to become "aggressive" as defined in the GALL (pH <5.50, Chloride (Cl) >500 ppm, Sulfates (SO_4) >1500 ppm).

RAI B.3.37-3

Background

IN 2004–05 identified leakage of spent fuel pools at several existing nuclear power plants.

Issue

In the operating experience review, the applicant stated that the DAEC spent fuel pool has been leaking since at least 1994 and this leakage only appears in the spent fuel pool liner drains.

Request

1. Provide a chemical analysis of the leakage and the spent fuel pool water which demonstrates that the leakage originates in the spent fuel pool. Include pH in the chemical analysis.
2. Provide the basis for the conclusion that the leakage is entirely contained within the liner drain system and is not leaking through the surrounding concrete.

DAEC Response to RAI B.3.37-3

The amount of leakage has been quantified; it averages about 280 ml/day (or about 10 fl. oz/day or 0.4 fl. oz/hour). DAEC is continuing to monitor leakage.

Part 1

Chemical analysis is not sufficient to confirm or disprove that the source is the spent fuel pool; however, no other source is plausible.

Part 2

Walkdowns have been completed in accessible areas under the spent fuel pool and no leaks were evident. These areas include the skimmer surge tank room, the decay tank room, the RWCU pump room, and second floor open areas. The RWCU heat exchanger room is also accessed on an occasional basis and no leaks have been reported. The new spent fuel vaults were also inspected for accumulated water and none was found.

RAI B.3.38-1

Background

The scope of the Thermal Aging and Neutron Irradiation Embrittlement of CASS AMP in NUREG-1801, Rev. 1, Section XI.M13 indicates that the method to determine susceptibility includes evaluating the ferrite content of the material. NUREG-1801, Rev. 1, Section XI.M13 continues to explain that it is acceptable to evaluate the ferrite content by using the Hull's equivalent factors as described in NUREG/CR-4513, Rev 1.

Issue

The DAEC LRA, Appendix B, Section B.3.38 indicates that the applicant's Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is consistent with the NUREG-1801, Rev. 1 Section XI.M13 and does not take any exceptions. In addition, the alloy for the CASS materials considered under the applicant's Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is 351 Grade CF8, which has a maximum molybdenum concentration of 0.5 wt. percent as per the latest ASTM standard. The 1976 ASTM standard does not provide a maximum value for the 351 CF8 alloy. The applicant described in their Thermal Aging and Neutron Irradiation Embrittlement of basis document (LRAP-M013) that the Hull's equivalent factors were used to calculate the percent ferrite in their plant-specific CASS material. The applicant used 0.0 wt. percent for molybdenum in their calculations. Secondly, the applicant stated that it based the nitrogen concentrations used in the Hull's equivalent equations on the values found in NUREG/CR-4513, Rev 1. The applicant used 0.04 wt. percent for nitrogen, however, the nitrogen concentration in NUREG/CR-4513, Rev 1. can be as low as 0.028 wt. percent. Using a molybdenum and nitrogen concentration of 0.0 and 0.04 wt. percent, respectively led to a final ferrite concentration of 23.28 wt. percent. However, if the molybdenum and nitrogen concentration of 0.5 and 0.028 wt. percent would have been used, respectively, the ferrite concentration of 28.93 wt. percent would have been calculated. It is unclear to the staff the basis for choosing the molybdenum and the nitrogen concentrations of 0.0 and 0.04 wt. percent, respectively for use in the Hull's equivalent factors.

Request

Provide additional information that justifies use of 0.0 wt. percent for molybdenum in Hull's equivalent factors when the maximum concentration of 0.5 wt. percent is possible. Provide additional information that justifies use of 0.04 wt. percent nitrogen in Hull's equivalent factors when NUREG/CR-4513, Rev 1. indicates that nitrogen may be as low as 0.028 wt. percent. Furthermore, if updated values for molybdenum and nitrogen indicate that the ferrite content is greater than 25 percent, provide additional information describing what additional actions will be taken regarding flaw evaluation to be consistent with the GALL Report.

DAEC Response to RAI B.3.38-1

The most current ASTM specification for CASS 351 Grade CF8 has a maximum molybdenum concentration of 0.5 weight percent. The 1976 ASTM standard for the CASS 351 Grade CF8 alloy, which was used in the previous DAEC calculation, does not provide a maximum value for molybdenum. In order to be conservative, the DAEC calculation of the Hull's equivalent equation has been revised to use the 0.5 weight percent maximum value for molybdenum.

The DAEC calculation based the nitrogen concentrations used in the Hull's equivalent equations on the values found in NUREG/CR-4513, Rev. 1. Table 1 in NUREG/CR-4513, Rev. 1, lists out the chemical composition (including nitrogen) of various heats of cast stainless steels. However the document specifically states, "If not known, the nitrogen content can be assumed to be 0.04 weight percent." The nitrogen content in the respective CASS materials at DAEC is unknown. Per NUREG/CR-4513, Rev. 1, the DAEC calculation of the Hull's equivalent equation used the nitrogen value of 0.04 weight percent.

Using a revised molybdenum content of 0.5 weight percent, and continuing to use a nitrogen concentration of 0.04 weight percent, the final ferrite concentration of the DAEC CASS materials was conservatively determined to be 20.99 weight percent.

Because the specific chemistries of the components are not currently available, calculations for the percent delta ferrite in these components are limited to the worst case scenario for the chemistry ranges given in ASTM 351 Grade CF8 materials. As it is unlikely that the DAEC components actually contain the worst case scenario of the chemistry ranges, the delta ferrite calculational results are most likely extremely conservative. Calculated in this manner, the delta ferrite result for DAEC CASS components was determined to be 20.99 weight percent. It should be noted that for most heats, the difference between the estimated and measured values is ± 6% ferrite. Although NUREG/CR-4513, Rev. 1 makes a notation regarding the 6% difference, it does not specify this addition to the margin of the calculated delta ferrite. Because the addition is not required and not used in the calculational examples in NUREG/CR-4513, Rev. 1, DAEC did not consider it for the calculation. The delta ferrite weight percent of 20.99 was the result of using values of 0.50 and 0.04 for Molybdenum and Nitrogen, respectively.

NUREG 1801, Section XI.M13 (GALL) provides the NRC guidance for determining if a program is required and the expected inspection criteria.

The GALL states:

> The reactor vessel internals receive a visual inspection in accordance with the American Society of Mechanical Engineers (ASME) Code Section XI, Subsection IWB, Category B-N-3. This inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of cast austenitic stainless steel (CASS) reactor vessel internals. This aging

management program (AMP) includes:

(a) identification of susceptible components determined to be limiting from the standpoint of thermal aging susceptibility (i.e., ferrite and molybdenum contents, casting process, and operating temperature) and/or neutron irradiation embrittlement (neutron fluence), and

(b) for each "potentially susceptible" component, aging management is accomplished through either a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed as part of the applicant's 10-year in-service inspection (ISI) program during the license renewal term, or a component-specific evaluation to determine its susceptibility to loss of fracture toughness.

Additionally, the GALL states that the CASS material is susceptible if it is exposed to temperatures in excess 482°F and neutron fluence of greater than 10^{17} n/cm2 (E>1 MeV). The CASS material internal to the reactor at DAEC meets both of these criteria.

The material composition (specifically the percent ferrite) of the CASS material is critical in determining the inspection technique.

To determine the percent delta ferrite content for the CASS material DAEC used Hull's Equivalent equation as follows:

The Hull's equivalent factor equations given in Section 3.2 of NUREG/CR-4513 Rev. 1 are as follows:

Cr_{eq} = Cr + 1.21(Mo) + 0.48(Si) – 4.99 (NUREG/CR-4513 equation 3.2.1)

Ni_{eq} = (Ni) + 0.11(Mn) – $0.0086(Mn)^2$ + 18.4(N) + 24.5(C) + 2.77 (NUREG/CR-4513 equation 3.2.2)

Ferrite content (δ_c) is given by $\delta_c = 100.3(Cr_{eq}/Ni_{eq})^2 - 170.72(Cr_{eq}/Ni_{eq}) + 74.22$ (NUREG/CR-4513 equation 3.2.3)

DAEC does not have Certified Material Test Reports for the respective CASS materials. Since the exact chemistry of the materials is unknown, the most conservative chemistry was selected from the material specification. The chemical content used for the determination of the delta ferrite content is taken from ASTM A 351-05 for Grade CF8 for all elements except nitrogen. The assumed value for nitrogen is from NUREG/CR 4513 Rev. 1. The values are as follows:

Cr = 18.0 to 21.0 % (21.0 % was used in the calculation. This number provided the most conservative percent delta ferrite.)

Mo = 0.50%

Si = 2.00 %

Ni = 8.0 to 11.0 % (8.0 % was used in the calculation. This number provided the most conservative percent delta ferrite.)

Mn = 1.50 %

N = 0.04 % (assumed value from NUREG/CR 4513 Rev. 1)

C = 0.08 %

Substituting these numbers into the equations for Cr_{eq} results in a value of

$Cr_{eq} = 21.0 + 1.21(0.50) + 0.48(2.00) – 4.99 = 17.57$ %

$Ni_{eq} = (8.0) + 0.11(1.50) – 0.0086(1.50)^2 + 18.4(.04) + 24.5(0.08) + 2.77$

$= 13.61$ %

The percent delta ferrite is calculated:

$\delta_c = 100.3 (Cr_{eq} / Ni_{eq})^2 – 170.72 (Cr_{eq} / Ni_{eq}) + 74.22$ %

$= 100.3 (17.57/ 13.61)^2 - 170.72 (17.57/13.61) + 74.22$

$= 20.99$ %

The delta ferrite content of the ASTM A 351 Grade CF8 CASS materials installed at DAEC is conservatively calculated as 20.99 percent. The percent delta ferrite content of the CASS material used in the vessel internal components at DAEC is greater than 20 percent; therefore, the potential for thermal embrittlement exists.

RAI B.3.38-2

Background

The detection of aging effects of the Thermal Aging and Neutron Irradiation Embrittlement of CASS AMP in NUREG-1801, Rev. 1, Section XI.M13 indicates that a supplemental inspection covering the components of interest may be used. In addition, the guidance indicates that the inspection technique used should be capable of detecting the critical flaw size with adequate margin, which will be based on service loading conditions and service-degraded material properties. NUREG-1801, Rev. 1 Section XI.M13 indicates that an acceptable enhanced VT-1 inspection would achieve a 0.0005-in resolution with the conditions of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique.

Issue

The DAEC LRA, Appendix B, Section B.3.38 indicates that the applicant's Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is consistent with the NUREG-1801, Rev. 1 Section XI.M13 and does not take any exceptions. It was indicated in the applicant's basis document LRAP-M013, Thermal Aging and Neutron Irradiation Embrittlement of CASS, in Section 3.4.2, that this AMP will use enhanced VT-1 inspections on the affected components during the 10-year inservice inspection program during the license renewal term. The applicant further stated that this enhanced VT-1 program would be able to detect the critical flaw size for this degradation process with adequate margin. The applicant's basis document did not provide any further information on the techniques that will be used for detecting tight cracks that may form in the CASS material from thermal and neutron irradiation embrittlement.

Request

Describe how the visual inspection used in this program will achieve the 0.0005-in flaw size resolution as indicated in NUREG-1801, Rev. 1 Section XI.M13. If not, provide additional information that demonstrates that the enhanced VT-1 technique will be able to detect the critical flaw size associated with thermal aging and neutron irradiation embrittlement of cast austenitic stainless steel.

DAEC Response to RAI B.3.38-2

NUREG-1801 XI.M13, Detection of Aging Effects, does not define a 0.0005 inch flaw resolution as a required standard to be met. This value is used as an example. NUREG-1801 XI.M13 states, "One example of a supplemental examination is enhancement of the visual VT-1 examination of Section XI IWA-2210. A description of such an enhanced visual VT-1 examination could include the ability to achieve a 0.0005-in. resolution, with the conditions (e.g., lighting and surface cleanliness) of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique." [emphasis added]

LRA Section B.3.38 Thermal Aging And Neutron Irradiation Embrittlement Of Cast Austenitic Stainless Steel (Cass) Program, Subsection B.3.38.1 Program Description, states, "DAEC inspects the reactor pressure vessel internals in accordance with the applicable requirements of ASME Section XI and BWRVIP documents." The description of a VT-1 examination is contained within the BWRVIP-03 and ASME Code Section XI as approved by 10 CFR 50.55a. All revisions to BWRVIP-03 are submitted to the NRC.

DAEC performs inspections of Reactor Vessel Internals in accordance with ASME Section XI requirements and BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines, BWRVIP-03. The resolution requirement for enhanced VT-1 in BWRVIP-03 is the same as for VT-1 in ASME Code Section XI. Both define the required resolution in terms of characters with a height of 0.044 inch. ASME Section XI, IWA-2210 (b) states, "For procedure demonstration, a test chart containing text with some lower case characters without an ascender or descender (e.g., a, c, e, o) is required. Measurements of the test chart shall be made once before initial use with an optical comparator (10X or greater) or other suitable instrument to verify that the height of a representative lower case character without an ascender or descender, for the selected type size, meets the requirements of Table IWA-2210-1." Table IWA-2210-1 defines the Maximum Procedure Demonstration Lower Case Character Height for VT-1 examinations as 0.044 in.

It is recognized that an earlier revision of BWRVIP-03 did specify the resolution of a .0005 inch line for procedure demonstration; however, this has since been revised to conform to the 0.044 inch character resolution defined in the ASME Code. Since the camera resolution, camera lenses, lighting requirements, surface cleanliness, water clarity, and other examination requirements remained the same, the examination results obtained would not be expected to change just because a character was used for the procedure demonstration rather than a line.

RAI B.3.39-1

Background

The water chemistry Parameters Monitored/Inspected, described in NUREG-1801, Rev. 1, Section XI.M2 indicates that the guidance in EPRI BWR water chemistry guidelines may be used to monitor reactor water chemistry to minimize exposure to contaminant concentration.

Issue

The DAEC LRA, Appendix B, Section B.3.39 indicates that the applicant's Water Chemistry System Program is consistent with the NUREG-1801, Rev. 1 Section XI.M2 and does not take any exceptions. In addition, the applicant indicates that its prevention and monitoring practices are based on the guidance from EPRI Boiling-Water Reactor Vessel and Internals Project (BWRVIP) – 130, BWR Water Chemistry Guidelines. The EPRI BWR Water Chemistry Guidelines in Table 6-6 indicates that condensate dissolved oxygen should be measured. However, the applicant's Water Chemistry Guidelines, Attachment 5, does not appear to indicate that condensate dissolved oxygen is measured. It is not clear to the staff why condensate dissolved oxygen is not monitored as suggested in the EPRI BWR Water Chemistry Guidelines.

Request

Provide additional information to justify why the condensate dissolved oxygen is not monitored in the Water Chemistry Program as suggested in the EPRI BWR Water Chemistry Guidelines.

DAEC Response to RAI B.3.39-1

Based on recent reviews, DAEC has determined that sampling for condensate dissolved oxygen should be implemented. A condition report was initiated to track resolution of this issue. A condensate sample was obtained from the sample point monitoring the condensate discharge from the condensate demineralizers. The sample analysis indicated the dissolved oxygen concentration was 40 ppb, well within the BWRVIP specification of 30-200 ppb. Procedure changes have been initiated to continue once per day condensate sampling for dissolved oxygen.

RAI B.3.39-2

Background

Monitoring and Trending described in the Water Chemistry Program in NUREG-1801, Rev. 1, Section XI.M2 indicates that the frequency of sampling water chemistry parameters will vary, but are based on the EPRI BWR Water Chemistry Guidelines. Furthermore NUREG-1801, Rev. 1, Section XI.M2 indicates that whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

Issue

In the DAEC LRA, Appendix B, Section B.3.39 indicates that the applicant's Water Chemistry System Program is consistent with the NUREG-1801, Rev. 1 Section XI.M2 and does not take any exceptions. Section 3.5.2 of the LRAP-M002 Water Chemistry program basis document, the applicant indicates that the program does not contain specific guidance to increase the sampling rate after corrective actions have been taken to address an abnormal chemistry condition. It is not clear to the staff why the technical basis document states that it is consistent with NUREG-1801 because it appears to take exception to the increased sampling rate suggested in the NUREG-1801.

Request

Provide additional information to justify why the DAEC LRA is not taking an exception to NUREG-1801, Rev. 1, when the applicant's LRAP-M002 document states it will not increase sampling due to an abnormal chemistry condition as indicated in NUREG-1801.

DAEC Response to RAI B.3.39-2

Based on recent reviews DAEC has determined that specific procedural guidance for increased sampling due to abnormal chemistry conditions is appropriate. The DAEC Water Chemistry Guidelines procedure has been revised to add guidance that will increase the sampling rate due to an abnormal chemistry condition. This procedure change brings this portion of the plant chemistry program into compliance with the GALL and therefore no exception is taken to NUREG-1801, Rev.1 XI.M2.

RAI B.4.2-1

Background

LRA Section 4.3 states that the DAEC Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the numbers of cycles of the design transients and assure action is taken prior to any analyzed numbers of transients being exceeded.

Issue

However, the LRA provides no description or discussion regarding how DAEC has been and will be monitoring the severity of pressure and thermal (P-T) activities during plant operations. It is essential that all thermal and pressure activities (transients) are bounded by the design specifications (including P-T excursion ranges and temperature rates) for an effective and valid AMP.

Request

1. Describe the methods that DAEC uses for tracking thermal transients and confirm that all monitored transient events are bounded by the design specifications.
2. Specify the time (years) over which actual transient monitoring and cycle tracking activities took place. If there have been periods for which transient events were not monitored since the initial plant operation, specify the affected time frame, and provide justification to demonstrate that the estimated cycles for this unmonitored period are conservative.
3. Provide a histogram of cycles accrued for plant startup, plant shutdown, and Loss of feedwater (FW) heater, FW heater bypass transients.

DAEC Response to RAI B.4.2-1

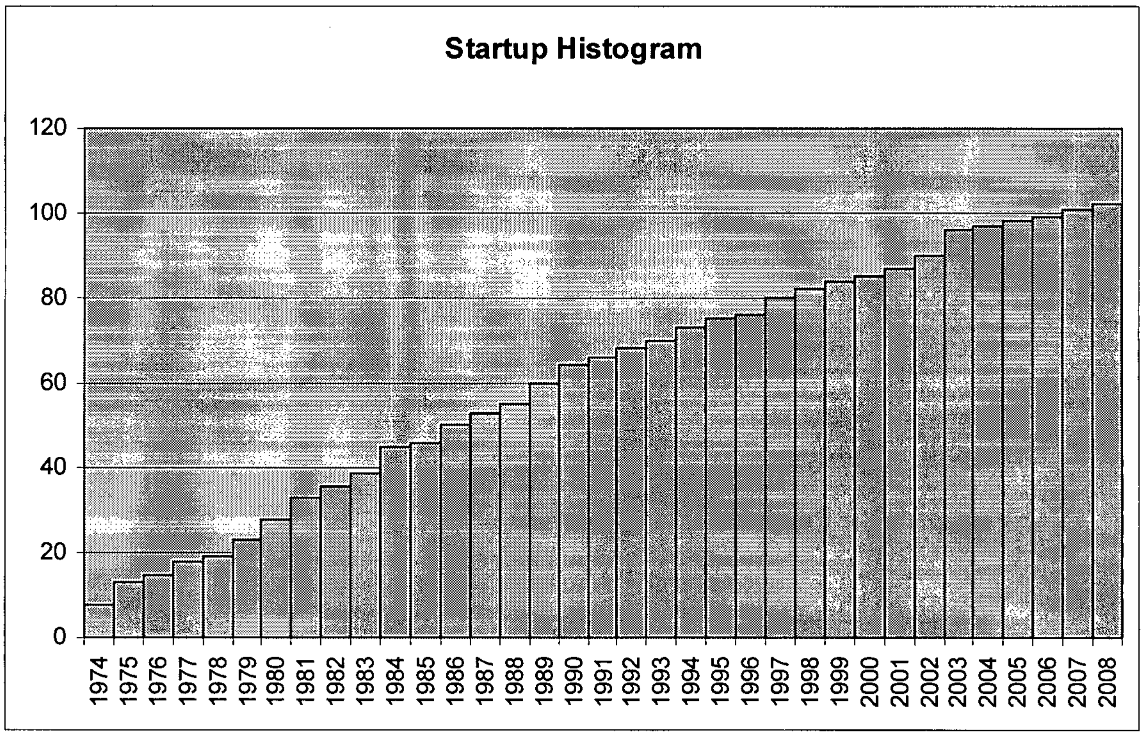
Part 1
The DAEC tracks thermal transients with a surveillance test procedure (STP) that is performed on a cyclic basis. Cycles are manually counted by reviewing various plant documents, including operator logs, maintenance rule data, and computer printouts. The data is reviewed, the plant response of the actual transient is compared to the design transient, and the monitored transient events are "binned" accordingly. This ensures that the actual transients are bounded by design and conservatively counted.

Part 2
Actual transient monitoring and cycle tracking activities began in 1998, when the STP described above was developed to track thermal cycles going forward. In order to determine the numbers of thermal cycles that had occurred since the plant began operation, and to serve as a "starting point" for the counts in the STP, past documentation was reviewed, including operator logs, to determine how many startups,

scrams, etc. had occurred. A thorough review was conducted in order to count startup/shutdown, Cold-to-Hot-to Cold ("aborted startup" cycles) and scram cycles. For the feedwater heater bypass event, a conservative estimate was made to serve as the "starting point" for those cycles. During the time that the STP has been performed, no feedwater heater bypass events have been recorded.

Part 3

A histogram for cumulative plant startups is provided below. Since the number of shutdowns is equal to the number of startups on a cyclic basis, but not a yearly basis, the numbers may vary by 1 (i.e., when the plant is operating, the cumulative number of startups is one greater than the cumulative number of shutdowns).



A histogram for feedwater heater bypass is not provided, since, as discussed in the response to (2) above, 1 event per fuel cycle was conservatively assumed (for a total of 14 events through RFO 14) to serve as a "starting point" for the STP. Since the tracking of the event via the STP, no feedwater heater bypass events have been recorded.

A histogram is not provided for the loss-of-feedwater-heater transient, since only one such transient has occurred (in 2000).

RAI B.4.2-2

Background

LRA B.4.2.5, on operating experience, states that inconsistencies in RPV fatigue cycle assumptions were identified in November 2006 during a review of RPV and piping calculations. The applicant states that this issue was addressed in the corrective action program and the corrective actions included revising the fatigue calculations as part of the license renewal project.

Issue

It is not clear to the staff what does the term "RPV fatigue cycle" means. In addition, the LRA does not discuss the effects of the cited inconsistence on the fatigue results.

Request

1. Explain the terminology "RPV fatigue cycle".
2. Summarize the corrective actions taken and the impact of the transient cycle inconsistence issue on fatigue results.

DAEC Response to RAI B.4.2-2

Part 1

The term "RPV fatigue cycle" was intended to refer to the cycle assumptions made in RPV fatigue evaluations. That is, LRA B.4.2.5 is referring to the inconsistencies identified between assumptions made in the 1998 fatigue reassessment and the power uprate fatigue analyses. These inconsistencies included, for example, the assumption of 160 startup/shutdown cycles in the 1998 fatigue reassessment vs. the assumption of 120 startup/shutdown cycles in the power uprate fatigue evaluation.

Part 2

The 1998 reassessment revised UFSAR Table 5.3-7, but did not revise all design documents. This contributed to the creation of the discrepancies between the power uprate fatigue evaluation (performed in 2000) and the 1998 evaluation. That is, the power uprate evaluations did not use the revised cycle counts of the 1998 reassessment, but did use revised stresses due to the uprate. The 1998 reassessment used the revised cycle counts, but used pre-uprate stresses. Therefore, in order to ensure that these inconsistencies had no adverse impact on the 60-year fatigue evaluations performed in support of license renewal, the information from both needed to be taken into account in the new evaluations. Accordingly, when the RPV fatigue evaluations were performed for the 60-year license renewal period, relevant assumptions and information from both the 1998 reassessment and the power uprate fatigue evaluation were considered. These 60-year evaluations also considered the impact of other evaluations, such as the revised fatigue evaluation for the main closure region mentioned in LRA Section 4.3.1.

Therefore, the inconsistencies discussed in Section B.4.2.5 have no impact on the 60-year fatigue evaluation results.

Corrective actions also included the revision of UFSAR Table 5.3-7. Further discussion is provided in the response to RAI 4.3.1-3.

RAI B.4.2-3

Background

LRA Section B.4.2.1 shows the program description of the DAEC Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Issue

The applicant devoted this section entirely for discussing environmental fatigue evaluation. While addressing the reactor water environment on fatigue life is important, the most vital part of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is to track the transient cycles and fatigue usage. However, this important part of the program is missing in the program description.

Request

Please consider including monitoring/tracking of transient cycles, and fatigue usage, in the program description.

DAEC Response to RAI B.4.2-3

In LRA Section B.4.2, Metal Fatigue of Reactor Coolant Pressure Boundary Program, Subsection B.4.2.1, Program Description, on page B-80, the first paragraph is revised to read as follows.

> The DAEC Metal Fatigue of Reactor Coolant Pressure Boundary Program is an existing program. The Program tracks the number of thermal and pressure transients for selected reactor coolant system components, in order not to exceed design limits on fatigue usage. The program ensures the validity of analyses that explicitly assumed a fixed number of thermal and pressure transients by assuring that the actual number of transients does not exceed the assumed limit. In accordance with NUREG/CR-6260, the impact of environmental effects on fatigue usage have been evaluated and shown to be less than the maximum allowable (1.0) for the sixty (60) year license renewal term of operation.

RAI B.4.2-4

Background

The onsite basis document shows that the DAEC AMP Element 4 states, "The DAEC thermal cycle monitoring program is performed periodically, on a frequency of at least once every fuel cycle".

Issue

GALL X.M1 AMP program element 4 requires that the AMP program provides periodic update of fatigue usage calculations. While updating transient cycles is important, tracking cycles alone, as Element 4 indicated it will do, is insufficient in situations in which unanticipated events occurred or structural geometry/configuration was modified. Under these circumstances, stress state is most likely changed, which will affect fatigue usage. Therefore, updating cycles alone is not enough fully meeting the AMP requirements.

Request

Describe how DAEC would address fatigue in the case where unanticipated situations such as structural configuration changes or unexpected transients occur.

DAEC Response to RAI B.4.2-4

In the event of structural configuration changes, the modification process ensures that ASME requirements, including the evaluation of stresses and fatigue, are addressed. Should discrepancies be identified in the design of vessel components or piping systems, they would be addressed via the Corrective Action Program. Resolution would include evaluation of fatigue usage, if so required.

Similarly, should unexpected transients occur, the situation would be evaluated via the Corrective Action Program. One such example is described in LRA Section B.4.2, Metal Fatigue of Reactor Coolant Pressure Boundary Program, Subsection B.4.2.5, Operating Experience. Trends were observed which indicated that the bottom head drain temperature had sharply decreased immediately following a reactor scram in June of 2000. This situation was identified in the Corrective Action Program and an evaluation was performed which considered various factors, including fatigue usage, and ensured the situation was acceptably resolved.

New Program Commitments RAI

Background

This RAI applies to all new AMPs.

Issue

Appendix A, Section 18.4, table A-1 of the LRA, contains commitments for each new AMP. In this table, the applicant uses words such as "develop" or "establish" to describe the action to be taken prior to the period of extended operation. The SRP-LR (tables 3.x-2 where x=1through 6) recommends the use of very precise language to describe the actions to be taken prior to the period of extended operation. In reviewing the new AMPs the staff has, in general, found that the language used in the SRP is contained within the AMP. However, the staff recognizes that it is possible to develop an AMP without implementing it. Given the possibility that an AMP could be developed and not implemented, it is not clear to the staff that the wording used by the applicant is consistent with the wording used in the SRP-LR.

Request

Please modify the commitments for new programs so that the commitment clearly states that the new program will be implemented prior to the period of extended operation.

DAEC Response to New Program Commitments RAI

In LRA Appendix A, Section 18.4 Table A-1 Duane Arnold License Renewal Commitments, the following commitment items have been revised to clarify that the program is to be implemented by the scheduled date. In addition, a footnote has been added to the entire table to define the term "implement" as used in the commitments.

Item No.	System, Component or Program	Commitment[1]	Section	Schedule
1.	Buried Piping and Tanks Inspection Program	Implement Buried Piping and Tank Program	18.1.7	Prior to the period of extended operation
4.	Electrical Cables and Connections Program	Implement an Electrical Cables and Connections Program and complete the first inspection prior to the period of extended operation.	18.1.17	Prior to the period of extended operation

Item No.	System, Component or Program	Commitment[1]	Section	Schedule
5.	Electrical Cables and Connections Used in Instrumentation Circuits Program	Implement an Electrical Cables and Connections Used in Instrumentation Circuits Program and complete the first inspection prior to the period of extended operation.	18.1.18	Prior to the period of extended operation
6.	Electrical Connections Program	Implement an Electrical Connections Program and complete the one time inspection prior to the period of extended operation.	18.1.19	Prior to the period of extended operation
7.	Electrical Penetration Assemblies Program	Implement an Electrical Penetration Assemblies Program.	18.1.20	Prior to the period of extended operation
11.	Fire Water System Program	Implement maintenance activities to perform volumetric examinations for pipe wall thinning of fire protection piping periodically during the period of extended operation.	18.1.23	Prior to the period of extended operation
17.	Fuel Oil Chemistry Program	Implement procedures to require bottom thickness testing of the Standby Diesel Generator Day Tanks and the Diesel Fire Pump Day Tank.	18.1.25	Prior to the period of extended operation
18.	Fuse Holders Program	Implement a Fuse Holders Program and complete the first test prior to the period of extended operation.	18.1.26	Prior to the period of extended operation
19.	Inaccessible Medium Voltage Cable Program	Implement an Inaccessible Medium Voltage Cable Program and complete the first inspection or test prior to the period of extended operation.	18.1.27	Prior to the period of extended operation

Item No.	System, Component or Program	Commitment[1]	Section	Schedule
20.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Implement an Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.	18.1.28	Prior to the period of extended operation
24.	Metal Enclosed Bus Program	Implement a Metal Enclosed Bus Program and complete the first inspection prior to the period of extended operation.	18.1.31	Prior to the extended operation
25.	One-Time Inspection Program	Implement a One-Time Inspection Program and complete the one-time inspections prior to the period of extended operation.	18.1.32	Prior to the period of extended operation
26.	Reactor Vessel Surveillance Program	Implement a procedure to evaluate the BWRVIP ISP data as it becomes available.	18.1.35	Prior to the period of extended operation
29.	Selective Leaching of Materials Program	Implement and complete a program to include one-time visual inspection and hardness measurement of selected components susceptible to selective leaching	18.1.36	Prior to the period of extended operation
36.	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	Implement a Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	18.1.38	Prior to the period of extended operation

[1]In the preceding table, the term "implement" means that the program is described in an approved procedure or other approved formal document; the test, inspection or monitoring procedure has been developed and approved; and the first test, inspection or monitoring activity has been scheduled.

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
1.	Buried Piping and Tanks Inspection Program	Implement Buried Piping and Tank Program [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.7	Prior to the period of extended operation
2.	BWR Vessel Internals Program	Perform an EVT-1 inspection of 5% of the top guide locations	18.1.14	Within six years of entering the period of extended operation
3.	BWR Vessel Internals Program	Perform an EVT-1 inspection of an additional 5% of the top guide locations	18.1.14	Within 12 years of entering the period of extended operation
4.	Electrical Cables and Connections Program	Implement an Electrical Cables and Connections Program and complete the first inspection prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.17	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
5.	Electrical Cables and Connections Used in Instrumentation Circuits Program	Implement an Electrical Cables and Connections Used in Instrumentation Circuits Program and complete the first inspection prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.18	Prior to the period of extended operation
6.	Electrical Connections Program	Implement an Electrical Connections Program and complete the one time inspection prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.19	Prior to the period of extended operation
7.	Electrical Penetration Assemblies Program	Implement an Electrical Penetration Assemblies Program. [Revised in DAEC letter NG-09-0764 in response to new Program Commitments RAI]	18.1.20	Prior to the period of extended operation
8.	External Surfaces Monitoring Program	Revise the inspection program to address inspector qualifications, types of components, degradation mechanisms, aging effects, acceptance criteria, inspection frequency, and periodic reviews to determine program effectiveness. The program will also specifically address inaccessible areas and include inspections of opportunity for possible corrosion under insulation. [Revised in DAEC letter NG-09-0764 in response to RAI B.3.21-2]	18.1.21	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
9.	Fire Protection Program	The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to include criteria for visual inspections of fire barrier wall, ceiling and floors to examine for any sign of degradation such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack and reaction with aggregates by fire protection qualified inspectors. [Revised in DAEC letter NG-09-0764 in response to RAI B.3.22-1]	18.1.22	Prior to the period of extended operation
10.	Fire Protection Program	Enhance procedures to inspect the entire diesel driven fire pump fuel supply line for age related degradation.	18.1.22	Prior to the period of extended operation
11.	Fire Water System Program	Implement maintenance activities to perform volumetric examinations for pipe wall thinning of fire protection piping periodically during the period of extended operation [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.23	Prior to the period of extended operation
12.	Fire Water System Program	Enhance procedures to include NFPA 25 criteria for sprinklers regarding replacing or testing	18.1.23	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
13.	Fire Water System Program	Enhance procedures to perform visual inspection of fire hydrants annually	18.1.23	Prior to the period of extended operation
14.	Fuel Oil Chemistry Program	Revise the program to require particulate testing of fuel oil samples from the diesel fire pump day tank	18.1.25	Prior to the period of extended operation
15.	Fuel Oil Chemistry Program	Enhance procedures to require sampling and testing of new fuel oil delivered to the diesel fire pump day tank; and to require that purchase orders and sampling procedures for diesel fuel delivered to and stored in the diesel fire pump day tank prohibit the delivery and use of biodiesel fuel. [Revised in letter NG-09-0764 in response to RAI B.3.25-1]	18.1.25	Prior to the period of extended operation
16.	Fuel Oil Chemistry Program	Enhance procedures to perform periodic (10 year) draining, cleaning and visual inspection of the diesel fuel oil day tanks, diesel fire pump day tank, and diesel driven air start air compressor fuel oil tanks. [Revised in letter NG-09-0764 in response to RAI B.3.25-4]	18.1.25	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
17.	Fuel Oil Chemistry Program	Implement procedures to require bottom thickness testing of the Standby Diesel Generator Day Tanks and the Diesel Fire Pump Day Tank. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.25	Prior to the period of extended operation
18.	Fuse Holders Program	Implement a Fuse Holders Program and complete the first test prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to RAI B.3.26-1 and New Program Commitments RAI]	18.1.26	Prior to the period of extended operation
19.	Inaccessible Medium Voltage Cable Program	Implement an Inaccessible Medium Voltage Cable Program and complete the first inspection or test prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.27	Prior to the period of extended operation
20.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Implement an Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.28	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
21.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program	Enhance procedures to monitor for corrosion and wear of the supporting steel and rails	18.1.29	Prior to the period of extended operation
22.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program	Enhance procedures to record usage of the reactor building and turbine building cranes	18.1.29	Prior to the period of extended operation
23.	Lubricating Oil Analysis Program	Enhance procedures to include diesel fire pump	18.1.30	Prior to the period of extended operation
24.	Metal Enclosed Bus Program	Implement a Metal Enclosed Bus Program and complete the first inspection prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.31	Prior to the extended operation
25.	One-Time Inspection Program	Implement a One-Time Inspection Program and complete the one-time inspections prior to the period of extended operation. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.32	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
26.	Reactor Vessel Surveillance Program	Implement a procedure to evaluate the BWRVIP ISP data as it becomes available. [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.35	Prior to the period of extended operation
27.	Reactor Vessel Surveillance Program BWRVIP-74-A BWR PRV Inspection and Flaw Evaluation Guidelines for License Renewal	Revise the Reactor Vessel Surveillance Program to implement the recommendations of BWRVIP-116 BWR Vessel and Internals Project Integrated Surveillance Program Implementation for License Renewal.	18.1.35	Prior to the period of extended operation
28.	Reactor Vessel Surveillance Program	Implement BWRVIP-116 with the conditions documented in Sections 3 and 4 of the NRC Staff's SE dated March 1, 2006 for BWRVIP-116	18.1.35	Prior to the period of extended operation
29.	Selective Leaching of Materials Program	Implement and complete a program to include one-time visual inspection and hardness measurement of selected components susceptible to selective leaching [Revised in DAEC letter NG-09-0764 in response to New Program Commitments RAI]	18.1.36	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
30.	Structures Monitoring Program	Enhance procedures to include structures and structural components not currently in Maintenance Rule Program	18.1.37	Prior to the period of extended operation
31.	Structures Monitoring Program	Enhance procedures to include periodic sampling of groundwater for pH, chloride and sulfate concentration on a 10 year periodicity.	18.1.37	Prior to the period of extended operation
32.	Structures Monitoring Program	Enhance procedures to include a elastomer inspection to prevent leakage through containment penetration	18.1.37	Prior to the period of extended operation
33.	Structures Monitoring Program	Enhance procedures to include a requirement to contact the proper personnel to allow opportunistic inspection of the buried concrete foundation	18.1.37	Prior to the period of extended operation
34.	Structures Monitoring Program	Enhance procedures to include opportunistic inspections of the buried concrete foundation on a 10 year periodicity	18.1.37	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
35.	Metal Fatigue of Reactor Vessel Coolant Pressure Boundary Program	Enhance procedures to incorporate the requirements of NUREG/CR-6260 locations into the implementing procedures	18.2.2	Prior to the period of extended operation
36.	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	Implement a Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. [Revised in DAEC letter NG-09-0764 in response to New Program Commitment RAI]	18.1.38	Prior to the period of extended operation
37.	BWR Vessel Internals Program	Inspect a sample of the rim hold-down bolts by VT-3 until an expanded technical basis for not inspecting is approved by the NRC.	18.1.14	Prior to the period of extended operation
38.	Reactor Vessel Circumferential Weld TLAA	Submit a relief request to address the frequency requirements of the inservice inspection of the RPV circumferential welds. (BWRVIP-05)	18.3.1.4	Prior to the period of extended operation
39.	Quality Assurance Program (Corrective Action, Confirmation Process, Administrative Controls)	Expand the scope of its 10 CFR Part 50, Appendix B Quality Assurance program to include non-safety-related structures and components subject to an AMR for license renewal.	UFSAR 17.1.2	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
40.	Operating Experience	Perform an operating experience review of extended power uprate and its impact on aging management programs for systems, structures, and components (SSCs) before entering the period of extended operation.		Prior to the period of extended operation
41.	Bolting Integrity Program	Revise the implementing procedures for the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program; ASME Section XI Inservice Inspection, Subsection IWF Program; External Surfaces Monitoring Program; Structural Monitoring Program; and Buried Piping and Tanks Program such that they specifically address the inspection of fasteners (bolting, washers, nuts, etc.) for signs of leakage, corrosion/loss of material, cracking, and loss of preload/loss of prestress, as applicable. [Added in letter NG-09-0764 in response to RAI B.3.6-02]	18.1.6	Prior to the period of extended operation
42.	BWR Penetrations Program	The implementing document for the BWR Penetrations Program will be revised to specify that guidance in BWRVIP-14, -59 and -60 is to be considered in the evaluation of crack growth in stainless steel, nickel alloys and low-alloy steels, respectively, when flaws are identified and evaluation required. [Added in letter NG-09-0764 in response to RAI B.3.10-5]	18.1.10	Prior to the period of extended operation

TABLE A-1
DUANE ARNOLD LICENSE RENEWAL COMMITMENTS[1]

Item No.	System, Component or Program	Commitment[2]	Section	Schedule
43.	Fire Protection Program	The DAEC Fire Barrier Penetration Seal Inspection surveillance procedure will be enhanced to ensure a approximately 10% of each type of penetration seal is included in the 35 percent selection of fire penetration seals that are visually inspected at an 18 month interval. [Added in letter NG-09-0764 in response to RAI B.3.22-1]	18.1.22	Prior to the period of extended operation
44.	Fire Protection Program	The DAEC Surveillance Procedure for the CO2 Cardox System Operability Annual Test will be enhanced to include a step to perform an inspection for corrosion and mechanical damage to system components. [Added in letter NG-09-0764 in response to RAI B.3.22-1]	18.1.22	Prior to the period of extended operation
45.	ASME Class 1 Small-bore Piping Inspection Program	Implement an ASME Code Class 1 Small-bore Piping Inspection Program [Added in letter NG-09-0764 in response to RAI B.3.3-2]	18.1.40	Prior to the period of extended operation

[1] Table is updated to reflect DAEC correspondence through 10/13/2009
[2] In the table, the term "implement" means that the program is described in an approved procedure or other approved formal document; the test, inspection or monitoring procedure has been developed and approved; and the first test, inspection or monitoring activity has been scheduled.