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419-321-7676

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L-21-266

10 CFR 50.55a

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Subject:
Davis-Besse Nuclear Power Station
Docket No. 50-346, License No. NPF-3
Response to Request for Additional Information on Proposed Inservice Inspection Alternative RR-A2 (EPID L-2021-LRR-0067)

By letter dated September 13, 2021 (ADAMS Accession No. ML21256A119) and in accordance with 10 CFR 50.55a(z)(1), Energy Harbor Nuclear Corp. submitted a request for a proposed alternative to certain requirements of inservice inspection (ISI) to the American Society of Mechanical Engineers, Section XI, Table IWB-2500-1, Examination Category B-B, and Table IWC-2500-1, Examination Category C-A and C-B for use at Davis-Besse Nuclear Power Station. The proposed alternative is to increase the inspection interval for the items from 10 years to 30 years.

The Nuclear Regulatory Commission (NRC) staff determined that additional information is needed to complete the review of the proposed alternative. A public meeting was held on November 8, 2021 with Energy Harbor Nuclear Corp. representatives to discuss the draft request for additional information (RAI). As a result of this meeting, Energy Harbor Nuclear Corp. informed the NRC staff that a response to the RAI would be provided, but this proposed alternative would no longer be needed for the spring 2022 refueling outage, as originally requested.

By electronic mail dated November 16, 2021 (ADAMS Accession No. ML21321A379), the NRC staff issued the RAI to support the review of the proposed alternative. The Energy Harbor Nuclear Corp. RAI response is provided in the Attachment. A copy of site procedure EN-DP-00355, "Determination of Allowable Operating Transient Cycles," is also enclosed, as requested.

There are no regulatory commitments contained in this submittal. If there are any questions or if additional information is required, please contact Mr. Phil H. Lashley, Manager - Fleet Licensing, at (330) 696-7208.

Sincerely,

Terry J. Brown

Attachment: Response to Request for Additional Information

Enclosure: EN-DP-00355, Determination of Allowable Operating Transient Cycles

cc: NRC Region III Administrator
NRC Resident Inspector
NRC Project Manager
Utility Radiological Safety Board

By letter dated September 13, 2021 (ADAMS Accession No. ML21256A119), Energy Harbor Nuclear Corp. submitted a request for a proposed alternative to certain requirements of inservice inspection (ISI) to the American Society of Mechanical Engineers (ASME) Section XI, Table IWB-2500-1, Examination Category B-B, and Table IWC-2500-1, Examination Category C-A and C-B for use at Davis-Besse Nuclear Power Station (Davis-Besse). The proposed alternative is to increase the inspection interval for the items from 10 years to 30 years. By electronic mail dated November 16, 2021 (ADAMS Accession No. ML21321A379), the Nuclear Regulatory Commission (NRC) staff requested additional information to support the review of the proposed alternative. The requested information is provided below. The request for additional information (RAI) is presented in bold font, followed by the Energy Harbor Nuclear Corp. response.

RAI-1

The application does not provide sufficient information regarding the welds and nozzles for the Davis-Besse replacement SGs [steam generators] that are included in the proposed alternative.

A. Discuss whether the replacement SGs are completely new or are hybrid replacements that include components from the original SGs (e.g., welds or nozzles). If the replacement SGs are hybrid SGs, identify the SG welds and nozzles included in the proposed alternative that are from the original SGs and justify why the transient cycles used in the fatigue crack growth calculations for such welds are acceptable.

Response:

As identified in the September 13, 2021 proposed alternative, both SGs were replaced. In each case, a new once through steam generator was installed after the original once through steam generator (OOTSG) was removed. The welds included in the proposed alternative are from the replacement once through steam generators (ROTSGs).

B. Discuss the material specifications of the SG welds included in the proposed alternative.

Response:

The ROTSG pressure boundary is of all-forged construction using high strength low alloy forgings. The primary heads are single piece forged construction, including nozzle and manway stick-outs. The secondary shells are all-forged construction with no longitudinal seams and a minimum of circumferential seams.

The SG welds included in the proposed alternative are filler metal class E9018-G or EG (F-9P4-EG-G). The SG forgings are supplied in the quenched and tempered condition and qualified on the basis of mechanical properties after a simulated post-weld heat treatment (PWHT). This simulated PWHT conservatively bounds all anticipated PWHTs. The RT_{NDT} for each ROTSG pressure boundary plate, forging, or weld is equal to or less than 0°F.

C. Discuss which welding process (e.g., gas tungsten arc welding, shield metal arc welding) was used to fabricate the SG welds included in the proposed alternative.

Response:

The welding processes used to fabricate each of the SG welds is identified in Table 1 below. For eight of the welds, shielded metal arc welding (SMAW) and submerged arc welding (SAW) were used. SAW was used for the other four welds. Because no welding exists at the inside radius, a welding process is not applicable for the four inside radius components.

Table 1

Component ID	Welding Process
RC-SG-1-1-W23	SMAW and SAW
RC-SG-1-2-W23	SMAW and SAW
RC-SG-1-1-W22	SMAW and SAW
RC-SG-1-2-W22	SMAW and SAW
SP-SG-1-1-W65	SMAW and SAW
SP-SG-1-1-W69	SMAW and SAW
SP-SG-1-2-W65	SMAW and SAW
SP-SG-1-2-W69	SMAW and SAW
SP-SG-1-1-W127-X/Y	SAW
SP-SG-1-1-W128-W/X	SAW
SP-SG-1-2-W127-X/Y	SAW
SP-SG-1-2-W128-W/X	SAW
SP-SG-1-1-W127-X/Y-IR	N/A
SP-SG-1-1-W128-W/X-IR	N/A
SP-SG-1-2-W127-X/Y-IR	N/A
SP-SG-1-2-W128-W/X-IR	N/A

D. Discuss whether repairs were made on the subject SG welds and nozzles during fabrication of the replacement SGs. If repairs were made, discuss whether the weld residual stress analyses considered and modeled the repaired flaw in the weld residual analyses or explain why this was not necessary.

Response:

No repairs were made on the subject welds and nozzles during fabrication of the ROTSGs. Although, a linear indication on weld SP-SG-1-1-W65 was found after PWHT, this surface indication was blended smoothly into the surrounding area to reduce any stress concentrations. No repair welding was required after the surface conditioning.

RAI-2

Figure 1-2 in Attachment 1 to the proposed alternative shows cladding on SG welds for Item No. B2.40 of the ASME Code, Section XI, Table IWB-2500-1. However, Figures 1-3 and 1-4 in Attachment 1 do not show cladding on the SG welds and nozzles for Item Nos. C1.30, C2.21 and C2.22 of the ASME Code, Section XI, Table IWC-2500-1.

A. Confirm that cladding is not applied to SG welds and nozzles for Item Nos. C1.30, C2.21 and C2.22. Discuss the susceptibility to corrosion in the components without cladding.

Response:

Energy Harbor Nuclear Corp. confirms that cladding is not applied to the SG welds and nozzles from Item Nos. C1.30, C2.21, and C2.22.

Corrosion allowances were incorporated into the design of the ROTSGs. These allowances were intended to address material losses of the ROTSG components that are caused by general and flow-accelerated corrosion (FAC) during normal operation and layup, and by their exposure to chemical solvents that are used during chemical cleanings of the tube bundle on the secondary side. The design corrosion allowance considered weld material and low alloy steel pressure boundary materials. If the weld was part of the pressure boundary, the corrosion allowance set for the carbon steel pressure boundary was applied to the weld. The predicted general corrosion of carbon steel was determined for the 40-year design life of the ROTSG components, and wall thickness was designed to bound the predicted corrosion. Therefore, the identified components without cladding are not considered susceptible to corrosion.

B. Discuss whether the effect of cladding on SG welds covered under Item No. B2.40 is included in the plant-specific analyses (e.g., in the weld residual stress calculation).

Response:

The cladding for Item No. B2.40 was included in the finite element analysis (FEA) model for Item No. B2.40 in Electric Power Research Institute (EPRI) Report No. 3001205906 [Reference 1]. The FEA model is shown in Figure 7-19 of the EPRI report. Although the cladding was modeled in the FEA, it was not obvious whether its effect was included in the probabilistic fracture mechanics (PFM) analyses. In response to RAI-3c for Dominion Energy Nuclear Connecticut, Inc. (Dominion), Millstone Power Station, Unit 2 (Millstone) on this issue [Reference 2 and Reference 3], the effect of the cladding on the probability of rupture and leakage was evaluated and found to be negligible as noted by the NRC in Section 5.3 of the NRC safety evaluation (SE) for Millstone [Reference 4]. The same conclusion applies to Davis-Besse.

RAI-3

Section 5 of the proposed alternative states that the EPRI Reports provide the technical basis for the alternative. The licensee also stated that it performed a plant-specific analyses for Davis-Besse. Section 5, page 5, of the proposed alternative states that because the sensitivity studies performed in the EPRI Reports involve preservice inspection (PSI)/ISI scenarios that are different from those at Davis-Besse, supplemental analyses were performed for the plant-specific inspection scenarios at Davis-Besse. Section 5, page 10, of the proposed alternative states that the deterministic fracture mechanics (DFM) evaluations in the EPRI Reports provide verification of the probabilistic failure mechanics results for Davis-Besse. The licensee did not submit the plant-specific analyses with the proposed alternative and did not explain how the EPRI DFM evaluations verify the probabilistic failure mechanics results for Davis-Besse.

A. Submit the plant-specific analyses used to support this request.

Response:

The plant-specific analysis mentioned in the proposed alternative refers to the results of applying site-specific parameters to the EPRI report information to show applicability of the technical basis to Davis-Besse. This plant-specific information is provided in Attachment 1 of the proposed alternative. Supplemental analyses performed for Davis-Besse are described in the proposed alternative with the results summarized in Tables E-1, E-2, and E-3 of the proposed alternative. Therefore, the plant-specific analyses are included in the proposed alternative, not contained in a separate analysis document.

B. Discuss how the DFM evaluation in the EPRI Reports are applicable to Davis-Besse.

Response:

As shown in Table E-4 of the proposed alternative, there are differences between the geometry used in Reference 1 and EPRI Report No. 3002014590 [Reference 5], which make the stresses at Davis-Besse higher than those used in the EPRI reports. However, the results of the DFM evaluation in Table 8-3 of Reference 1 showed that the maximum stress intensity factor (K) is 33.9 ksi√in, which is considerably less than the allowable fracture toughness of 100 ksi√in. In addition, the minimum time for a through-wall leak to occur is 1,940 years, which is considerably more than the evaluation period of 80 years. Similarly, the results of the DFM evaluation in Table 8-31 of Reference 5 indicate that for the Babcock & Wilcox main steam nozzle, the maximum K is 40 ksi√in, and the time for a through-wall leak to occur is 716 years. Because of the very large margins obtained in the DFM evaluations in the EPRI reports, the differences in geometry and stresses between Davis-Besse and those in the EPRI reports can be accommodated. The initial flaw size used in the DFM evaluation in the EPRI reports [Reference 1 and Reference 5] is the largest allowed by ASME Code, Section XI, article IWA-3500. Davis-Besse does not have flaws larger than those permitted by the Code paragraph.

C. Provide a table comparing the plant-specific and EPRI analysis inputs for the SG welds and nozzles that includes the following information: crack dimensions, material stress intensity factor (K_{IC}), stress, stress multipliers, crack growth rate, number of flaws, flaw density for the nozzle inside radii, crack size (flaw depth and length) distribution, crack model, probability of detection, ISI schedule, examination coverage, treatment of analytical uncertainty, and number of realizations.

Response:

The plant-specific analysis performed for Davis-Besse used the same inputs as in the EPRI reports [Reference 1 and Reference 5] except those listed in Table 2 below. The Davis-Besse plant-specific parameters listed are all conservative as compared to those used in the EPRI reports.

Table 2

Parameter	EPRI Report [5] (Table 8-9)	Davis-Besse Plant Specific (Table E-1)
ISI Schedule	0	0, 30
Nozzle Flaw Density (IR)	0.001	0.1
Stress Multiplier	1.0	1.5

RAI 4

Section 7 of the EPRI Reports discusses the finite element analyses (FEA) to determine stresses due to internal pressure and thermal transients for the selected SG welds and nozzle geometries. Section 5, page 4, of the proposed alternative states that the FEA in the EPRI Reports are applicable to Davis-Besse as shown in Attachment 1 to the proposed alternative. The FEA in the EPRI Reports does not include applied seismic, deadweight, and transient loads nor loads from the main steam and reactor coolant system pipes onto the SG welds and nozzles. Attachment 1 to the proposed alternative does not provide sufficient information to show that the FEA in the EPRI Reports is applicable to Davis-Besse.

A. Discuss how the finite element models for Item Nos. B2.40, C1.30, C2.21 and C2.22 in the EPRI Reports are applicable to Davis-Besse.

Response:

A representative FEA model was developed for Item Nos. C2.21 and C2.22 as shown in Figure 7-11 of Reference 5. A representative FEA model was developed for Item No. B2.40 and Item No. C1.30 in Figure 7-19 of Reference 1. As discussed in Sections 4.5 and 4.6 of References 1 and 5, instead of performing plant-specific analysis, sensitivity analysis based on stress multipliers can be performed on these representative models to determine plant-specific stresses. As discussed in Sections 4.3.3 and 4.6 of Reference 5 and noted by the NRC in Section 3.8.3.1 of the SE for Southern Nuclear Operating Co. Inc. (SNC), Vogtle Electric Generating Plant Units 1 and 2 (Vogtle) [Reference 6], the dominant stress is the pressure stress. Therefore, the variation in the R_i/t ratio determined in Table E-4 of the proposed alternative can be used to scale up the stresses in Reference 1 and Reference 5 to obtain the plant-specific stresses for the Davis-Besse components. In the proposed alternative, the conservative stress multipliers determined in Table E-4 were compared to those used in performing the PFM analyses to determine the probabilities of rupture and leakage reported in Tables E-1, E-2, and E-3 and found to be acceptable. The stress multipliers based on the pressure stress were conservatively applied to all other stresses (thermal transient stresses and weld residual stresses) in the plant-specific PFM evaluation for Davis-Besse.

B. Discuss whether applied seismic, deadweight, and transient loads and loads from the main steam and reactor coolant system pipes onto the SG welds and nozzles are considered in the plant-specific analyses. If the loads are not considered, provide justification for excluding these loads.

Response:

As discussed in Section 5.2 of the EPRI reports [Reference 1 and Reference 5], attached piping loads (including seismic deadweight, and other similar loads) were not considered in the analysis since the nozzle portion is so much thicker than the piping loads, and therefore, the stresses at the nozzle location are relatively small compared to the pressure and thermal transients. This was found acceptable by the NRC in Section 5.3 of the NRC SE for Millstone [Reference 4] and Section 3.8.3.3 of the NRC SE for Vogtle [Reference 6].

RAI-5

The EPRI Reports use probability of detection (POD) curves based on the ASME Code, Section XI, Appendix VIII. Section 5, page 9, of the proposed alternative states that Davis-Besse does not use Appendix VIII procedures for all the examination categories, so use of the Appendix VIII POD curve may not be

appropriate for all of the items. However, the application does not state what POD curves were used in the Davis-Besse plant-specific analyses.

A. Describe the POD curves that were used in the Davis-Besse plant-specific analyses for each examination category (e.g., POD based on the ASME Code, Section XI, Appendix VIII or ASME Code, Section V).

Response:

Energy Harbor Nuclear Corp. employs ASME Code, Section XI, Appendix VIII qualified procedures and personnel as allowed by ASME Code, Section XI, Appendix I (I-2600) where examination coverage is greater than 90 percent. When the Appendix VIII technique cannot achieve greater than 90 percent coverage, ASME Code, Section V, Article 4 is used. Table 3 below provides details of the examination procedures used for each of the welds in the fourth ISI interval.

Table 3			
Item No.	**4th ISI Interval**		
	Scope	**Procedure(s) Used**	**Appendix VIII or Section V**
B2.40	PSI ISI	PDI-UT-6 54-ISI-805	Section XI, Appendix VIII Section XI, Appendix VIII
C1.30	PSI PSI PSI ISI	PDI-UT-6 PDI-UT-7 DB-UT33/1/0/0 54-ISI-130	Section XI, Appendix VIII Section XI, Appendix VIII Section V, Article 4 Section V, Article 4
C2.21	PSI PSI ISI	PDI-UT-6 PDI-UT-11 54-ISI-130	Section XI, Appendix VIII Section XI, Appendix VIII Section V, Article 4
C2.22	PSI ISI	PDI-UT-11 54-ISI-132	Section XI, Appendix VIII Section XI, Appendix VIII

As shown in Table 3, both ASME Code, Section V, Article 4 and ASME Code, Section XI, Appendix VIII procedures are used at Davis-Besse for both the preservice (PSI) and ISI inspections. There are no POD curves for the ASME Code, Section V examinations; hence, the ASME Code, Section XI, Appendix VIII POD curve (Figure 8-6 in Reference 1 and Figure 8-2 in Reference 5) was used in the plant-specific evaluations at Davis-Besse (the results of which are shown in Tables E-1, E-2 and E-3 in the proposed alternative). This POD curve is the same as those used in BWRVIP-108-A [Reference 7] and originated from EPRI report 1007984 [Reference 8].

B. Compare the POD curves used in the plant-specific analyses to the POD curve used in the EPRI Reports and explain why they are adequate for this application.

Response:

As explained in the response to part A above, both ASME Code, Section V, Article 4 and ASME Code, Section XI, Appendix VIII procedures are used for the examinations at Davis-Besse. However, the POD curve for ASME Section XI, Appendix VIII was used in the plant-specific evaluation for all the ASME Section XI Items at Davis-Besse since there are no POD curves for ASME Code, Section V examinations. This is deemed acceptable since based on the evaluation performed by the NRC in Section 10.2, of the Millstone SE [Reference 4] and Section 3.8.8.2, of the Vogtle SE [Reference 6], the use of the ASME Code, Section XI, Appendix VIII based POD curve for inspections based on ASME Code, Section V procedures would have minimal impact on the PFM results since the POD curve is not one of the parameters that significantly affect the PFM results.

RAI-6

The EPRI Reports show that during the beginning and ending of heatup and cooldown transients the operating temperature in the SGs could be as low as 70 degrees Fahrenheit (°F). Table 1-2 in Attachment 1 to the proposed alternative also shows 70 °F as the minimum heatup and cooldown temperature. At this low temperature, the K_{IC} value could be lower than the K_{IC} value at a higher SG operating temperature. The lower K_{IC} is more conservative than the higher K_{IC} value to limit the acceptability of a postulated flaw. The application does not state whether the plant-specific analyses considered the impact of the lower K_{IC} value on the Davis-Besse SG welds and nozzle inside radii.

Discuss the acceptability of the K_{IC} value used for the beginning and ending of heatup and cooldown transients for calculating the probability of failure and probability of leakage of the Davis-Besse SG welds and nozzle inside radii.

Response:

This issue was addressed during the NRC audit of the **PROMISE** Version 1.0 code [Reference 9, Item 2.e.iii)] for Item Nos. C2.21 and C2.22 of the feedwater nozzle at Vogtle and found acceptable in Section 3.8.4 of the NRC SE [Reference 6]. Since the feedwater nozzle transients are far more severe than the main steam nozzle transients, it is concluded that the analysis provided in support of Vogtle bounds that of Davis-Besse.

The issue was also addressed for the most limiting component in response to RAI-4 for the SG welds covered by the report at Millstone [Reference 2 and Reference 3] and was found acceptable in Section 6 of the NRC SE [Reference 4]. Since the transients at

Millstone are the same as those at Davis-Besse, the analysis provided in support of Millstone is applicable to Davis-Besse.

RAI-7

Tables E-1, E-2, and E-3 of the proposed alternative show the probability of leakage and probability of failure for Item Nos. B2.40, C1.30, C2.21 and C2.22 from year 10 to year 80. The NRC staff noted that the probability of leakage and probability of failure in Tables E-1, E-2, and E-3 of the proposed alternative are higher than the corresponding values in the EPRI Reports. Also, different stress multipliers were used to determine the results in Tables E-1, E-2, and E-3.

A. Discuss why different stress multipliers were used to determine the results in Tables E-1, E-2, and E-3 for the subject SG welds and nozzle inner radii.

Response:

In Table E-1, the stress multiplier of 1.5 was chosen to be consistent with that used in Table 8-28 of EPRI Report 3001204590 [Reference 5] to get a comparison of the probability of rupture and leakage between the feedwater nozzle (used in the EPRI report) and the main steam nozzle used in the proposed alternative. That comparison showed that there is significantly more margin in the main steam nozzles compared to the feedwater nozzle. With that information, in Tables E-2 and E-3, the stress multipliers were chosen by an iterative process to produce a probability of rupture or leakage as close as possible to the acceptance criteria of 1.0E-06. This information was then used with the variation in the R/t ratios in Table E-4 to determine acceptability of Davis-Besse components on a plant-specific basis.

B. Identify the specific probability of leakage and probability of failure for the proposed PSI + 30 ISI interval for each Item Nos. B2.40, C1.30, C2.21 and C2.22 as shown in Tables E-1, E-2, and E-3.

Response:

As stated in the proposed alternative, the ROTSGs were installed at Davis-Besse in 2014. The proposed alternative is to increase the inspection interval to 30 years from the current ASME Code, Section XI requirement of 10-year intervals for the remainder of the fourth 10-year inspection interval and through the sixth 10-year inspection interval, which is scheduled to end on September 20, 2042. The existing 60-year operating license will expire on April 22, 2037. Hence, from installation of the ROTSGs to the license expiration date is approximately 24 years. Based on this time period and the results presented in Tables E-1, E-2, and E-3 of the proposed alternative, Table 4 below provides conservative probabilities of rupture and leakage for the various Item Nos. at Davis-Besse at the time of license expiration.

Table 4 Probabilities of Rupture and Leakage for Davis-Besse Item Nos. B2.40, C1.30, C2.21, and C2.22 at License Expiration			
Item No.	**Table from Proposed Alternative**	**Probability per Year**	
		Rupture	**Leakage**
C2.21	E-2	2.37E-08	4.33E-09
C2.22	E-1	4.33E-10	4.33E-10
B2.40/C1.30	E-3	7.03E-08	4.33E-09

RAI-8

Tables 1-2, 1-3, and 1-4 in the application provide a comparison of the 60-year projected transient cycles in the plant-specific analyses and the EPRI Reports. A footnote to each table states, in part, that: "The 60-year projected cycles were determined as part of license renewal and are identified in EN-DP-00355, Determination of Allowable Operating Transient Cycles." The NRC staff noted that there are differences between the transient cycle information provided in Tables 1-2, 1-3, and 1-4 and the information provided as part of the license renewal application (ADAMS Accession Nos. ML102450572 and ML11159A132). In addition, the license renewal information was provided before the steam generators were replaced in 2014. Therefore, it is not clear how the transient cycles were projected to 60 years.

A. Provide Procedure No. EN-DP-00355.

Response:

A copy of procedure EN-DP-00355 is enclosed.

B. Discuss in detail how the transient cycles in Tables 1-2, 1-3, and 1-4 are projected to 60 years and how this relates to the replacement SGs that were installed in 2014.

Response:

The information provided as part of the license renewal application (ADAMS Accession No. ML102450572), Section 4.3.1.2 Projected Cycles, documents how the 60-year projected cycles were determined. The number of cycles accrued up to February 2008 were compiled. These accrued cycles were linearly extrapolated to 60 years of operation to determine whether the incurred cycles would remain below the number of design cycles. The results were presented in Table 4.3-1, 60-Year Projected Cycles.

Table 4.3-1 was updated and replaced in its entirety in the license renewal supplement (ADAMS Accession No. ML11159A132) based on the response to RAI B.2.16-1.

Procedure EN-DP-00355, “Determination of Allowable Operating Transient Cycles,” uses the 60-year projected cycles as the transient limits except where the cycle limit is reduced for a specific location. The procedure manages fatigue of select primary and secondary components for Davis-Besse, including the reactor vessel, reactor internals, pressurizer, and steam generators by monitoring and tracking the number of critical thermal and pressure transients as required by Technical Specification 5.5.5, “Allowable Operating Transient Cycles Program.” The procedure scope includes those components that have been identified to have a fatigue time-limited aging analysis (TLAA).

The procedure prevents the fatigue TLAAs from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The procedure uses the systematic counting of transient cycles and the evaluation of operating data to ensure that the allowable cycle limits are not exceeded, thereby ensuring that component fatigue usage limits are not exceeded. Transient documentation is updated at least once per plant operating cycle.

The ROTSGs were evaluated for the original design transient cycles for fatigue, which bounds the 60-year projected cycles. The fatigue usage factor for locations covered in this proposed alternative impacted by environmental effects were shown to remain less than 1.0 as part of license renewal. No reduction in transient cycles was taken based on the number of cycles accrued at the time of installation.

C. **Tables E-1, E-2, and E-3 show failure and leakage probability values to 80 years. However, Tables 1-2, 1-3, and 1-4 show transient cycles projected to 60 years. Discuss whether the probability of failure and probability of leakage values for 80 years were calculated based on the transient cycles projected to 60 years or to 80 years.**

Response:

The probability of rupture and the probability of leakage (per year) for 80 years were based on transient cycles projected to 80 years. The 60-year projected cycles were prorated to 80 years.

RAI-9

Section 5, page 9, of the proposed alternative states that Table E-4 “shows that the largest variation of the R/t [radius-to-thickness] ratio between the geometry evaluated in [EPRI Report 3002014590] and those at Davis-Besse is 28 percent, which is lower than the stress multipliers applied in the sensitivity studies in Tables E-1 through E-3.” However, the application does not explain why an R/t

ratio difference of 28 percent is lower than the stress multipliers applied in the sensitivity studies. In addition to the geometric variation, Tables 1-2 and 1-3 of Attachment 1 to the proposed alternative indicate there are differences in transient temperatures and pressures between the generic analyses in the EPRI Reports and the operation conditions at Davis-Besse. The geometric and transient temperature and pressure differences may affect the overall stresses in the Davis-Besse SG welds and nozzles.

A. Explain how the R/t ratio difference of 28 percent between the geometry evaluated in EPRI Report 3002014590 and that at Davis-Besse is lower than the stress multipliers applied in the sensitivity studies as shown in Tables E-1 through E-3.

Response:

As explained in Section 4.2 of the EPRI reports [Reference 1 and Reference 5] and accepted by the NRC in SEs [Reference 4 and Reference 6], the pressure stress is the dominant stress, and therefore the R/t ratio provides a means of scaling up the plant-specific stresses relative to the geometry used in the EPRI reports. The R/t ratio difference of 28 percent between the Davis-Besse geometry and the geometries used in the EPRI reports [Reference 1 and Reference 5] indicates that to obtain plant-specific stresses for Davis-Besse, the stresses in the EPRI reports need to be scaled by 1.28. The stress multipliers used in the sensitivity study of Table E-1 (1.5), Table E-2 (1.9) and Table E-3 (1.6) are greater than the 1.28 scaling factor required to obtain the plant-specific stresses at Davis-Besse and are therefore conservative. Furthermore, the stress multipliers derived based on the pressure stress were conservatively applied to all other stresses (thermal transient stresses and residual stresses) in the determination of the probabilities of rupture and leakage in Tables E-1, E-2, and E-3 of the proposed alternative.

B. Discuss the impact of the differences in temperature and pressure on the stresses in the Davis-Besse SG welds and nozzles.

Response:

As discussed in part A above, the impact of the temperature and pressure stresses at Davis-Besse was accounted for by the stress multipliers in the results presented in Tables E-1, E-2, and E-3 in the proposed alternative.

C. Discuss whether a plant-specific stress analysis was performed. If not, discuss the applicability of the generic stress analyses of the EPRI Reports to the Davis-Besse SG welds and nozzle inner radii.

Response:

No new FEA model was developed, and no new stress analyses were performed with a new FEA model specifically for Davis-Besse. As explained in part A above, stress multipliers were applied to the stresses from the EPRI reports [Reference 1 and Reference 5] to obtain the stresses for the Davis-Besse components.

RAI-10

Attachment 2 to the proposed alternative presents the inspection history of the Davis-Besse SG welds and nozzles in the replacement and original SGs. The examination tables in Attachment 2 show that the examination results are all acceptable. However, the application does not explain why the inspection history of the original SGs is relevant to this application.

A. Discuss how the inspection history of the original SGs was used to support this proposed alternative. Discuss whether the inspection of the original SGs was used to determine the probability of leakage and failure of the SG welds and nozzles in the replacement SGs.

Response:

The inspection history of the OOTSGs was provided to underline that the inspection of both the old and replacement SGs have not identified any adverse conditions, and the general operational history of the SGs at Davis-Besse has been successful. The OOTSGs were not used in the determination of the probabilities of rupture and leakage.

B. Clarify what is meant by "acceptable" examination results (e.g., no recordable indications were detected, or indications were detected but the acceptance standards of the ASME Code were met).

Response:

Examination results are deemed acceptable when the acceptance standards of the ASME Code are met. For the results listed in Attachment 2 of the proposed alternative that pertain to the ROTSGs, all but one examination had no recordable indications detected. The examination dated August 22, 2013 for SP-SG-1-1-W65 had an indication that met the acceptance standards of the ASME Code.

C. Discuss the acceptance criteria to disposition the detected indications during the PSI and ISI and identify the provisions of the ASME Code that were used to disposition the indications.

Response:

ASME Code, Section XI, Articles IWB-3500 and IWC-3500 were used as acceptance criteria and detected indications were dispositioned in accordance with these articles. More specifically, Table IWC-3510-1 was used to disposition the indication for SP-SG-1-1-W65.

D. Discuss which nondestructive examination method was used in the PSI and ISI of the subject SG welds and nozzle inner radii.

Response:

For Item Nos. B2.40, C1.30, and C2.22, ultrasonic testing (UT) was the nondestructive examination method used in the PSI and ISI of the subject SG welds and inner radii. For Item No. C2.21, UT was used for PSI and both UT and magnetic particle (MT) were used for ISI.

E. Discuss whether the flaw size used in the plant-specific analyses bounds the indications detected in the PSI and ISI.

Response:

In the DFM evaluation, a flaw size corresponding to the largest flaw size allowed by ASME Code, Section XI, Articles IWB-3500 and IWC-3500 acceptance standards, was used as the initial flaw size. This flaw size bounds the indications detected in the PSI and ISI. The DFM evaluation, summarized in Section 8-4 of the EPRI reports [Reference 1 and Reference 5], demonstrates that even with this bounding initial flaw size, the time to failure is in excess of 80 years and the maximum applied stress intensity factor (K) is below the ASME Code, Section XI allowable fracture toughness.

F. Discuss whether the examination history confirms that the generic analyses in the EPRI Reports is reasonable for Davis-Besse.

Response:

For conservatism, the examination history used in the proposed alternative was PSI only. Because the ISI examinations for the current interval have not been completed, credit was not taken for these examinations. The use of PSI only was considered with the most important parameters in the plant-specific PFM evaluation for Davis-Besse (the results of which are presented in Tables E-1, E-2, and E-3 of the proposed alternative) and found acceptable. Historic examination results for the OOTSGs indicate that Davis-Besse does not suffer from damage mechanisms that are not considered in the EPRI reports; therefore, the reports are reasonable for Davis-Besse.

RAI-11

Section 5, page 11, of the proposed alternative states that "all other inspection activities, including the system leakage test (Examination Categories B-P and C-H) will continue to be performed consistent with this request for alternative and in accordance with all other ASME Section XI requirements, providing further assurance of safety." However, the application does not identify other relevant inspections that will be performed to ensure safety.

A. Discuss any visual examinations, walkdowns, boric acid corrosion program inspections, or other inspections that may be performed to detect any potential leakage from the subject SG welds and nozzles as part of defense-in-depth measures.

Response:

In addition to the inspection activities performed in accordance with ASME Section XI requirements, boric acid corrosion (BAC) control walkdowns and inspections are performed on plant systems and components designated as ASME Class 1 and 2 every refueling outage. This includes the reactor coolant system (RCS). BAC walkdowns are conducted prior to decontamination activities inside containment, and inspections are performed during forced or planned outages.

During steady state plant operations, RCS leakage is closely monitored to ensure leakage stays within limits established by Technical Specifications. Unidentified RCS leakage can be a direct indicator of reactor coolant pressure boundary integrity. A surveillance test for RCS water inventory balance is performed at least once per 72 hours in MODE 1 through 4 during steady state operations. In this test, the total RCS leakage is calculated by resolving changes in initial and final values of pressurizer and RCS makeup tank levels over a minimum of one to four hours (or longer if desired), and providing corrections based on RCS temperatures and pressures to ensure the RCS leak rate is within required limits during MODE 1 through 4. Identified and unidentified leak rates are determined using the calculated leak rate and known leak rates.

The reactor coolant pressure boundary leak detection system includes the containment sump level/flow monitoring system. The containment sump level and flow monitoring system design includes containment vessel normal sump level indication in the control room. Flow rates are obtained by monitoring pump run time and multiplying by a flowrate. Analyses of reactor coolant inventory trends and containment vessel normal sump level changes also provide positive indication of reactor coolant system leakage to the containment vessel.

B. Discuss whether the reactor coolant system leakage detection systems can detect leakage from the subject SG welds and nozzle.

Response:

As described above, the RCS water inventory balance determines identified and unidentified leak rates. This data is used for trending of the leaks. Leakage from the SG welds and nozzles would initially appear as an increasing trend in unidentified leakage. Upon narrowing down the leakage source to be within containment, additional walkdowns or inspections would be used as needed to determine the exact leakage source.

C. Discuss any sensors, instrumentations, or coolant inventory calculations that could detect leakage from the subject SG welds and nozzles.

Response:

The containment vessel normal sump level and flow monitoring system includes a level indication in the control room. The sump contains 30 gallons per inch of height. Any significant increase in sump level will be detected in the control room.

RAI-12

By letters dated January 11 and July 16, 2021 (ADAMS Accession Nos. ML20352A155 and ML21167A355, respectively), the NRC approved proposed alternatives to extend the inspection interval for SG welds and nozzle inner radii at Vogtle Electric Generating Plant, Units 1 and 2 (Vogtle), and Millstone Power Station, Unit No. 2 (Millstone), respectively. These approved alternatives were both based, in part, on the EPRI Reports and were identified as precedents in Section 7 of the proposed alternative for Davis-Besse. Vogtle, Millstone, and EPRI generally concluded that the ISI interval for SG welds and nozzles could be extended when only PSI without any other post-PSI examinations had been performed. However, in the associated NRC safety evaluations, the NRC staff found that these general conclusions were unacceptable because, in part, these general conclusions do not account for the effect of the combination of the most significant parameters or the added uncertainty of low probability events.

The Davis-Besse application does not provide sufficient information to demonstrate that the structural integrity of the subject SG welds and nozzle inner radii can be ensured for the next 30 years without further inspections because ISI is the most effective measure for detecting changes in degradation or new degradation in the subject components under service conditions. Davis-Besse has performed only PSI and a partial ISI of its replacement SGs and is proposing to extend the interval to 30 years for the subject SG components. Davis-Besse has not performed a complete ISI of all the subject SG welds and nozzles in the fourth 10-year ISI interval. The application does not identify if or when the fourth interval ISI of the subject SG components will be completed.

Section 5, page 5, of the Davis-Besse application states that the plant-specific evaluations were performed assuming PSI only. However, the application does not address the concerns previously raised by the NRC staff regarding extending the ISI interval for the subject SG components based on PSI only without any other post-PSI examinations.

A. Identify the SG welds and nozzle inner radii, including identifications, that need to be inspected to complete the examinations required by the ASME Code, Section XI, in the fourth 10-year ISI interval.

Response:

The following two SG welds need to be inspected to complete the examinations required by the ASME Code, Section XI, in the fourth 10-year ISI interval: RC-SG-1-1-W23 (Item No. B2.40) and SP-SG-1-1-W69 (Item No. C1.30). No nozzle inner radii inspections are needed to complete the required examinations for the fourth 10-year ISI interval.

B. Identify when Davis-Besse will complete the ISI of the subject SG welds and nozzle inner radii for the fourth 10-year ISI interval, as required by the ASME Code.

Response:

Examination of the two remaining welds is to be completed in the refueling outage scheduled to occur in March 2022.

C. If the ISI will not be completed in the fourth 10-year ISI interval, justify how the structural integrity of the subject SG welds and nozzle inner radii can be maintained for 30 years without additional inspections. This justification should address the concerns the NRC staff raised in the January 11 and July 16, 2021, safety evaluations for Vogtle and Millstone, respectively.

Response:

As indicated in parts A and B above, Energy Harbor Nuclear Corp. plans to complete the remaining ISI examinations during the fourth 10-year ISI interval. This will provide a complete 10-year ISI interval of performance monitoring in addition to the PSI. Therefore, the PFM evaluation results presented in Tables E-1, E-2, and E-3 of the proposed alternative are conservative in application to Davis-Besse since only PSI inspection was assumed in the PFM evaluation.

RAI-13

Section 5, page 3, of the proposed alternative states that the licensee is "requesting an inspection alternative to the examination requirements of the

ASME, Section XI, Tables IWB-2500-1 and IWC-2500-1," for specific examination categories and item numbers. Section 5, page 3, goes on to state: "The proposed alternative is to increase the inspection interval for these item numbers for the replacement steam generators at Davis-Besse to 30 years." The term "inspection interval" is defined in the ASME Code, Section XI, IWA-2430 as the 10-year time period in which all inspection requirements of Section XI must be met. The application needs to clearly identify the specific requirements for which the alternative is being requested.

Clarify whether the licensee is seeking an alternative to the examination requirements of the ASME Code, Section XI, IWB-2500 and IWC-2500, for the item numbers specified in the application or an alternative to the definition of an inspection interval in the ASME Code, Section XI, IWA-2430.

Response:

Energy Harbor Nuclear Corp. is seeking an alternative to the examination requirements of the ASME Code, Section XI, Tables IWB-2500-1 and IWC-2500-1 for the examination categories and item numbers specified. While the alternative would increase the time span between inspections, there is no intent to change the definition of the term "inspection interval" in ASME Code, Section XI, IWA-2430.

RAI-14

The application states that the 2007 Edition through 2008 Addenda of the ASME Code, Section XI, is applicable to the fourth 10-year ISI interval at Davis-Besse. The application requests approval for the remainder of the fourth interval through the sixth interval. However, the application does not identify the Edition and Addenda of Section XI that will be applicable to the fifth and sixth ISI intervals. The NRC staff understands that the licensee cannot provide this information for the sixth interval at this time.

Identify the specific Edition and Addenda of the ASME Code, Section XI, that will apply to the fifth 10-year ISI interval at Davis-Besse, including the start and end dates for the interval. For the fifth interval, identify the specific provisions of Section XI for which the proposed alternative will be used (e.g., see Section 3 of the proposed alternative request).

Response:

The ASME Code, Section XI, 2017 Edition (no addenda) will apply to the fifth 10-year ISI interval, which is currently scheduled to start on September 21, 2022 and end on September 20, 2032. The specific provisions identified in Section 3 of the proposed alternative request remain the same in the 2017 Edition (no addenda). Therefore, the proposed alternative will use the same provisions in the fifth 10-year ISI interval.

REFERENCES

1. *Technical Bases for Inspection Requirements for PWR Steam Generator Class 1 Nozzle-to-Vessel Welds and Class 1 and Class 2 Vessel Head, Shell, Tubesheet-to-Head and Tubesheet-to-Shell Welds.* EPRI, Palo Alto, CA: 2019. 3002015906 (ADAMS Accession No. ML20225A141).

2. Email Letter from R. Guzman (NRC) to S. Sinha (Dominion), “Millstone Unit 2 - Request for Additional Information - Alternative Request RR-05-06 Inspection Interval Extension for SG Pressure Retaining Welds and Full-Penetration Welded Nozzles (EPID: L-2020-LLR-0097),” dated February 3, 2021 (ADAMS Accession No. ML21034A576).

3. Letter from G. T. Bischof (Dominion), “Dominion Energy Nuclear Connecticut, Inc., Millstone Power Station Unit 2 – Response to Request for Additional Information for Alternative Request RR-05-06 - Inspection Interval Extension for Steam Generator Pressure-Retaining Welds and Full-Penetration Welded Nozzles,” dated March 19, 2021 (ADAMS Accession No. ML21081A136).

4. SE from J. G. Danna (NRC) to D. G. Stoddard (Dominion), “Millstone Power Station Unit 2 – Authorization and Safety Evaluation for Alternative Request No. RR-05-06 (EPID L-2020-LLR-0097),” dated July 16, 2021, (ADAMS Accession No. ML21167A355).

5. *Technical Bases for Inspection Requirements for PWR Steam Generator Feedwater and Main Steam Nozzle-to-Shell Welds and Nozzle Inside Radius Sections.* EPRI, Palo Alto, CA: 2019. 3002014590 (ADAMS Accession No. ML19347B107).

6. Letter from M. T. Markley (NRC) to C. A. Gayheart (SNC), “Vogtle Electric Generating Plant Units 1 and 2 – Relief Request for Proposed Inservice Inspection Alternative VEGP-ISI-ALT-04-04 to the Requirements of the ASME Code (EPID L-2020-LLR-0109),” dated January 11, 2021, ADAMS Accession No. ML20352A155).

7. *BWRVIP-108: BWR Vessels and Internals Project, Technical Basis for the Reduction of Inspection Requirements for the Boiling Water Reactor Nozzle-to-Shell Welds and Nozzle Blend Radii*. EPRI, Palo Alto, CA: 2002. 1003557.

8. *Reactor Pressure Vessel Inspection Reliability Based on Performance Demonstrations*. EPRI, Palo Alto, CA: 2004. 1007984.

9. Letter from J. G. Lamb (NRC) to C. A. Gayheart (SNC), “Vogtle Electric Generating Plant, Units 1 and 2 – Audit Report for the PROMISE Version 1.0 Probabilistic Fracture Mechanics Software Used in Relief Request VEGP-ISI-ALT-04-04 (EPID L-2020-LLR-0109),” dated December 10, 2020 (ADAMS Accession No. ML20258A002).

ADMINISTRATIVE PROCEDURE TITLE SHEET
ED 7171-2

DAVIS-BESSE NUCLEAR POWER STATION EXCELLENCE • QUALITY • TEAMWORK	TITLE Determination Of Allowable Operating Transient Cycles	NO. EN-DP-00355 REVISION 10 PAGE 1 OF 25 EFFECTIVE DATE 03/15/21 SUPERSEDES

Prepared by: Barney Needham

Procedure Owner: Supervisor - Nuclear Engineering Programs

LEVEL OF USE:

GENERAL REFERENCE

TABLE OF CONTENTS

1.0 PURPOSE

The purpose of this procedure is to describe the Allowable Operating Transient Cycles (AOTC) for Davis-Besse Unit 1 for which permanent records are required, to specify documentation for each transient classification, and to assign responsibility for maintaining these records.

This procedure manages fatigue of select primary and secondary components for Davis-Besse Unit 1, including the reactor vessel, reactor internals, pressurizer, and steam generators by monitoring and tracking the number of critical thermal and pressure transients as required by Technical Specification 5.5.5, "Allowable Operating Transient Cycles Program." The scope includes those components that have been identified to have a fatigue time-limited aging analysis (TLAA).

This procedure prevents the fatigue TLAAs from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The procedure uses the systematic counting of transient cycles and the evaluation of operating data to ensure that the allowable cycle limits are not exceeded, thereby ensuring that component fatigue usage limits are not exceeded. Transient documentation is updated at least once per plant operating cycle.

This document implements a NRC commitment to manage the effects of aging for systems, structures and components within the scope of license renewal during the period of extended operation.

This document is credited for managing the effects of aging per 10CFR54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

2.0 SCOPE

This procedure applies to all Nuclear Group personnel and all external support personnel at Davis-Besse Nuclear Power Station.

3.0 REFERENCES

3.1 Developmental

3.1.1 Davis-Besse Unit 1, USAR, Section 5.1.4, Reactor Coolant System Service

3.1.2 Davis-Besse Unit 1, USAR, Table 5.1-8, Transient Cycles - 40 Year Design Life

3.1.3 RCTS Commitments O11705, O12326, and O12477

3.1.4 License Renewal Commitment DB-L-10-221-LRAA.1-09, DB-L-10-221-LRAA.1-23

3.1.5 Quality Assurance Program Manual, B.15.c

3.1.6 Davis-Besse Modification Package 00-0061, Permanent Canal Seal Plate

3.1.7 Areva Document 18-1149327-005, Reactor Coolant System Functional Specification

3.1.8 Areva Document 32-5021091-000, DHRS Swapover Transient Definition – DB

3.1.9 Areva Document 51-9162098-000, DB-1 NSSS Design Transients-Review of USAR, RCS Functional Specification, and AOTC Administrative Procedure

3.1.10 Babcock & Wilcox 205S-B6, Davis-Besse ROTSG Transient Load Summary

3.1.11 Babcock & Wilcox 205S-O&M-01, Replacement Once Through Steam Generator Operating and Maintenance Manual

3.1.12 Babcock & Wilcox 205S-SR-02-R0, Replacement Once Through Steam Generator Transient Analysis Stress Report

3.1.13 Framatome Calculation 32-5019410, DB-1 PCSP Seal Membrane Analysis

3.1.14 GE Steam Turbine Instruction, GEK-46385, Starting and Loading (Vendor Manual M-3-613)

3.1.14 Calculation C-ME-099.20-007, Davis-Besse Environmentally Assisted Fatigue (EAF) Screening

3.1.15 Teledyne Engineering Services Report TR-3831-13 dated 1/7/83, High-Pressure Injection Piping Problems

3.1.16 Teledyne Engineering Services Report TR-6388-2, dated 11/15/85, Davis-Besse Nuclear Power Station Reconciliation of ASME Section III Evaluations of Class I Pressurizer Relief Piping

3.1.17 Calculation C-ME-099.20-001

3.1.18 Calculation C-ME-099.20-003

3.1.19 Calculation C-ME-099.20-004

3.1.20 Calculation C-ME-099.20-005

3.1.21 Calculation C-ME-099.20-006

3.1.22 Notification 601283578, Evaluate Pressurizer Spray Nozzle Cycles

3.2 Implementation

3.2.1 Technical Specification 5.5.5, Allowable Operating Transient Cycles Program

3.2.2 NOP-OP-1002, Conduct of Operations

3.2.3 DB-PF-06703, Miscellaneous Operation Curves

3.2.4 NA-QC-00356, Transient Assessment Program

3.2.5 NOP-LP-2001, Corrective Action Program

4.0 DEFINITIONS

4.1 FEEDWATER TEMPERATURE VARIATION TRANSIENT - For the purposes of this procedure, the feedwater temperature variation transient is defined to have occurred when feedwater temperature is outside the limits shown in Fig. cc 8.2 of DB-PF-06703. Feedwater temperature will remain within acceptable limits when feedwater heaters are in normal line up. This transient can occur only when several feedwater heaters are bypassed. Low feedwater temperatures during plant start up that exist because the feedwater heater train line up has not been completed do not constitute a feedwater temperature variation transient unless feedwater temperature is below 185°F.

4.2 HOT FUNCTIONAL TESTING - Hot Functional Testing are those operations, prior to the initial core loading, wherein the NSSS is tested and qualified for core loading.

4.3 LOSS OF COOLANT - A major Loss of Coolant Accident (LOCA) which will depressurize the RCS and actuate the ECCS.

4.4 RAPID RCS DEPRESSURIZATION - For the purposes of this procedure, a rapid RCS depressurization is a short term, rapid cooling of the Reactor Coolant System by the Steam Generators in order to reduce the Reactor Coolant System pressure to a value less than the design pressure of the steam generators within 15 minutes. The objective of the rapid depressurization is to isolate a tube leak.

The initial conditions at the start of the transient are assumed to be hot standby with core decay heat by the steam generators dumping steam to the condenser. The turbine bypass control pressure is assumed to be 1050 psia. This gives an average Reactor Coolant System temperature of about 550°F. When the reactor coolant pressure is equal to or less than 1065 psia, normal cooldown commences.

4.5 RCS HEATUP AND COOLDOWN RATE - For the purposes of this procedure, a heatup or cooldown rate is defined as the maximum change in RCS Tave over any one hour period during the heatup or cooldown.

4.6 STEADY STATE POWER VARIATIONS - A Steady State Power Variation is defined as a ±1% variation in reactor power at any steady state power level.

4.7 STEAM GENERATOR BOILING DRY - A steam generator will be considered dry when as a result of a lack of feedwater addition, the start up range level indicates <16 inches or outlet pressure indicates <960 psig.

5.0 RESPONSIBILITIES

5.1 The Manager – Strategic Engineering shall be responsible for ensuring that all transients are reviewed and documentation is maintained up to date.

5.2 Design Engineering shall be responsible for the performance and maintenance of the environmentally - assisted fatigue (EAF) evaluations.

6.0 PROCEDURE

6.1 A listing and description of Allowable Operating Transient Cycles (AOTC) and possible sources of information is presented in Attachment 1. The transient descriptions are in accordance with References provided in Section 3.1. Several of the titles have been changed to more accurately represent the nature of the transients and/or for purposes of simplification.

6.2 The AOTC Program Owner may be required to interface with other departments such as Operations or Design Engineering when transient information is not readily available through conventional plant documentation.

NOTE 6.3

Several transients have been eliminated from documentation requirements due to their large number of allowable cycles. They are marked N/A in the Status Log.

6.3 Transient data can be collected through use of numerous methods and medium. In addition to such sources as the Unit Narrative Log, Operator Rounds Module, Condition Reports, Completed Tests, and Transient Assessment Reports, plant computer points and interfacing with the responsible organization can also be valuable sources of transient information, data analysis, and validation of data. Possible sources of transient data are also included in Attachment 1.

6.4 The AOTC logs shall be used to log the number of cycles experienced by each High Pressure Injection nozzle.

6.5 Transient cycle data shall be added to the corresponding transient in the AOTC Status Log to obtain the total number of that particular transient experienced by the plant.

6.6 Attachments 2 and 3 contain the documentation for each AOTC event. These sheets shall be retrievable from the master file.

6.9 To facilitate data collection and to maintain records current, the transient documentation shall be updated at least once per operating cycle.

6.10 When the sum of transients in the AOTC Logs indicate that the total number of transients is within 75% of the designated number of design cycles or within 10% of the 60-year projected cycles (shown in Attachment 1) for any transient classification, a condition report shall be initiated. Some of the environmentally-assisted fatigue (EAF) evaluations, discussed below, used 60 year projected cycles versus design cycles. The 60-year projected cycles are more limiting than the design cycles and therefore, become the allowable when considering environmental effects. When the accumulated cycles approach the allowable cycles, corrective action is taken that includes an engineering evaluation to ensure the Code design limit of 1.0 is not exceeded, including environmental effects where applicable. For transient cycles that are projected to exceed the allowable cycle limit by the end of the next plant operating cycle (Davis-Besse operating cycles are normally two years in duration), the corrective action shall include an update of the fatigue usage calculation for the affected component(s). Acceptance criterion is to maintain the cumulative fatigue usage below the Code design limit of 1.0 through the period of extended operation, including environmental effects where applicable.

For license renewal, the effects of the reactor coolant environment on component fatigue life have been addressed by assessing the impact of the environment on a sample of critical components as identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The subject components and associated EAF evaluations are provided in the table as follows:

NUREG/CR-6260 generic locations	Davis-Besse plant-specific locations	EAF Evaluation (AREVA Document)
1 Reactor vessel shell and lower head	Incore instrument nozzle	32-9140671-000
	Vessel shell and lower head	32-9116935-000
2 Reactor vessel inlet and outlet nozzles	Reactor vessel inlet nozzle	
	Reactor vessel outlet nozzle	
3 Pressurizer surge line	Hot leg surge nozzle inside radius	32-9119659-001
	Piping adjacent to outboard end of hot leg surge nozzle	
	Piping elbows	32-9118118-001
	Piping straights	
	Piping to pressurizer surge nozzle safe end weld	
	Pressurizer surge nozzle inside radius	32-9119659-001
	Pressurizer surge nozzle safe end	
4 HPI/Makeup nozzle	HPI/Makeup nozzle	32-9122270-002
	HPI/Makeup nozzle safe end	
5 Reactor vessel core flood nozzle	Nozzle	32-9116935-000
6 Decay heat Class 1 piping	Decay heat to core flood tee	32-9128305-000

In addition, a commitment was provided in the License Renewal Application (LRA) to address additional plant-specific component locations that may be more limiting than those considered in NUREG/CR-6260. This commitment is as follows.

Evaluate additional plant-specific component locations in the reactor coolant pressure boundary that may be more limiting than those considered in NUREG/CR-6260. This evaluation will include identification of the most limiting fatigue location exposed to reactor coolant for each material type (i.e., CS, LAS, SS, and NBA) and that each bounding material/location will be evaluated for the effects of the reactor coolant environment on fatigue usage. Nickel based alloy items will be evaluated using NUREG/CR-6909. Submit the evaluation to the NRC one year prior to the period of extended operation. The screening of the plant specific component locations is documented in Calculation C-ME-099.20-007.

Also, the Cummulative Usage Factors (CUFs) including environmental effects were greater than the acceptance criteria of 1.0 for the the high pressure injection nozzle safe ends including the associated Alloy 82/182 welds. Therefore, a commitment was provided in the LRA as follows:

In association with the TLAA for effects of environmentally assisted fatigue of the high pressure injection (HPI) nozzle safe end including the associated Alloy 82/182 weld (weld that connects the safe end to the nozzle), replace the HPI nozzle safe end including the associated Alloy 82/182 weld for all four HPI nozzles prior to the period of extended operation. Apply the Fatigue Monitoring Program to evaluate the environmental effects and manage cumulative fatigue damage for the replacement high pressure injection (HPI) nozzle safe ends and associated welds. The HPI nozzle safe end and alloy 82/182 were replaced in 19RFO per Engineering Change Package 12-0450.

6.11 The transients described in Attachment 1 are for equipment design purposes only. They show maximum anticipated rates of change of RCS and secondary side parameters during various types of incidents and do not necessarily represent actual or expected operating transients or procedures. Actual transients should be fit as closely as possible to the categories listed here.

6.12 Unless specifically noted in the transient description on Attachment 1, each step of a cycle as described in Reference 3.1.16 shall be counted as a separate transient.

6.13 When completing an entry in the appropriate log include as much relevant information as possible in the description section. This may include the initial or final conditions (power, temperature, pressure, etc.), cause of event, duration and frequency of abnormal steam generator operations, or other such data.

6.14 The AOTC program owner or designee shall determine if the replacement of a component that is addressed by the AOTC procedure warrants the resetting of the transient count. For example, the replacement of the OTSG would reset the transient count for the OTSG welded plugs.

6.15 The AOTC program owner or designee should periodically conduct a self-assessment in accordance with the requirements of NOBP-LP-2001.

7.0 <u>RECORDS</u>

7.1 The following quality-assurance records are completed by this procedure and shall be listed on the Nuclear Records List, captured, and submitted to Energy Harbor Enterprise Records Management in accordance with NOP-SS-3300 at least once per cycle.

7.1.1 AOTC Status Log

7.2 The following non-quality assurance records are completed by this procedure and may be captured and submitted to Energy Harbor Enterprise Records Management, in accordance with NOP-SS-3300.

7.2.1 None.

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS
Page 1 of 6

Transient Number	Description	Design Cycles / 60-yr Projected Cycles [16]
1*	Heatups from Cold Shutdown and Cooldowns to Cold Shutdown	
	1A - Heatup from 70°F to 8% Full Power(Normal)[2,5]	240 / 114 (best estimate)
	1B - Cooldown from 8% Full Power (Normal)[2,5]	240 / 114 (best estimate)
	1C – Natural Circulation Cooldown(Emergency)[3,6]	20 / 2
2*	Power Change 0 to 15% and 15% to 0% (Normal)	1,440 / 205 (0 to 15%) and 94 (15 to 0%)
3*	Power Loading 8% to 100% (Normal)[4]	1,800 / 1800
4*	Power Unloading 100% to 8% (Normal)[4]	1,800 / 1800
5*	10% Power Step Load Increase (Normal)	8,000 / 67
6*	10% Power Step Load Decrease (Normal)	8,000 / 140
7*	Step Load Reduction (100 to 8%) (Upset)	
	7A - Resulting from turbine trip	160 / 8
	7B - Resulting from electrical load rejection	150 / 4
8*	Reactor Trip (Upset)	
	8A - Low RC flow directly causes Rx trip (Upset)	40 / 4
	8B - High RC outlet temperature, high RC pressure or overpower trip - assumes a turbine trip occurs without automatic control system action. (Upset)	160 / 47
	8C - High RC pressure resulting from loss of feedwater (Upset)	88 / 26
	8D - Other trips, including the following (Upset): (1) Any reactor trip which meets the definition of another transient classification (e.g., Transients 11, 15, 16, and 17) will also be recorded under 8D. (2) Any reactor trip which does not fit into any other category will be classified as 8D.	112 /110
	8E – Similar to 8A but RC Pumps are tripped (Emergency)[3,6]	20 / 20

∗ Required by USAR[1]

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS

Transient Number	Description	Design Cycles / 60-yr Projected Cycles [16]
9*	Rapid Depressurizations	
	9A – Rapid RCS Depressurization (Upset)	40 / 4
	9B – Rapid Depressurization, trip RC Pumps (Emergency)[3,6]	10 / 10
10*	Change of reactor coolant flow (typical change of flow transient is loss of one RCP) without Reactor Trip (Upset)	20 / 10
11*	Rod Withdrawl Accident (Upset)	40 / 40 (2[17])
12*	Hydrotests (Test)[15]	
	12A – RCS Components Except OTSG Secondary (includes 5 shop tests)	20 / 9
	12B – ROTSG and Replacement RCS PIPING (Flowmeter to ROTSG) (includes 1 shop test)	10 / 3
13	Deleted (formerly Steady State Power Variations)	Not Applicable
14*	Control Rod Drop (Upset)	40 / 18
15*	Loss of Station Power (Upset)	40 / 6
16*	Steam Line Failure (Faulted)	1 / NA
17*	Steam Generator Boiling Dry	
	17A – Loss of feedwater to one steam generator (Upset)	20 / 6
	17B – Stuck open turbine bypass valve (Emergency)[3]	10 / NA
18*	Loss of Feedwater Heater (Upset)	40 / 40 (2[17])
19*	Feed and Bleed Operations (Normal)[4]	4,000 / 4,000
20*	Makeup and Pressurizer Spray Transients	
	20A – Makeup Flow Transient 1 (Normal)[4]	30,000 / 30,000
	20B – Makeup Flow Transient 2 (Normal)[4]	4.0 E+6 / 4.0 E+6
	20C – Spray Valve/Pressurizer Spray Nozzle (Normal)[4]	20,000 / 20,000

∗ Required by USAR[1]

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS
Page 3 of 6

Transient Number	Description	Design Cycles / 60-yr Projected Cycles
21*	Loss of coolant accident (LOCA) (Faulted)	1 / NA
22*	Test Transients	
	22A1 – High Pressure Injection System (Normal)[12]	40 / NA
	22A2 – HPI System Pressure Isolation Integrity Test	40/11 (1-1) 40/13 (1-2) 40/44 (2-1) 40/48 (2-2)
	22B - Core Flooding Check Valve (Normal)	240 / 26
	Both HPI System Pressure Isolation Integrity Tests and RCS Rapid Depressurization events (Transients No. 9A and 9B) are included in the count for Transient Number 22A2. The projection rate of future cycles for HPI Nozzles 1-1, 1-2, 2-1 and 2-2 are based on the five-year period from 1/25/2003 to 2/19/2008, to include only the current test methodology. Accrued cycles as of 1/25/2003 for HPI Nozzles 1-1, 1-2, 2-1 and 2-2 were respectively 9, 8, 17, and 14. This current test methodology does not cycle nozzles 1-1 and 1-2. Therefore the 60-year projection cycles for HPI Nozzles 1-1 and 1-2 are equal to the cycles that occurred before 1/25/2003 plus the two occurrences of rapid RCS Rapid Depressurization events (See Transient Number 9A). HPI piping evaluated for design and 60 year projected cycles in document 32-9260622-000. (See Request for Additional Information L-11-166)	
23*	Steam Generator Filling, Draining, Flushing and Cleaning (Normal)	
	23A – Steam Generator Seondary Side Filling	
	Condition 1 [7,11]	120 / NA
	Condition 2 [8,11]	120 / NA
	23B – Steam Generator Primary Side Filling	
	Condition 1 [9,11]	120 / NA
	Condition 2 [10,11]	120 / NA

∗ Required by USAR[1]

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS

Transient Number	Description	Design Cycles / 60-yr Projected Cycles
	23C – Steam Generator Flush [11]	40 / NA
	23D – Steam Generator Chemical Cleaning [11]	20 / NA
24*	Hot Functional Testing (Normal)	1 / 1
25*	Decay Heat Removal Swapping Transient [13]	20 / 20
26	Pressurizer Heaters	
	26A - Design life at full capacity with 5,000 cycles is 10,000 hours.	5,000 / NA
	26B - Design life at full capacity with 20,000 cycles is 2,500 hours.	20,000 / NA
	Recording of transient 26 cycles is not necessary. Useful data is impossible to obtain. Pressurizer heater cycles are not counted. They are not fatigue events.	
27	Pressurizer Relief Valves[(a)]	
27A	Code Relief Operation (RC13A, RC13B)	30[(b)] / 30
27B	Electromatic Relief (PORV) [c)]	
Condition 1	Temp ≥400°F	270 / 96
Condition 2	Temp < 400°F	25 / 25
	(a)These limits temperature/cycles are due to thermal/structural restraints on the pressurizer safety valve lines and welds and not on design limitations on the valves.	
	(b)This is the original limit determined when a loop seal existed on the discharge piping. Detailed analysis has not been performed following relocation of the valves and piping, but the new value will not be lower.	
	(c) If the valve cycles, the following information shall be recorded in the description section of the AOTC EVENT LOG (Attachment 2): A) The number of lifts B) The time between lifts C) The upstream piping temperature prior to actuation (computer point T772)	

∗ Required by USAR[1]

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS

Page 5 of 6

Transient Number	Description	Design Cycles / 60-yr Projected Cycles
28	Generator Operation Abnormal Frequency	
	Operation outside 60 ± 0.6 HERTZ should be limited in accordance with the following table:	
	Between	Approximate Time
	57.6 - 58.1 Hz	1 min
	58.1 - 58.6 Hz	12 min
	58.6 - 59.4 Hz	90 min
	60.6 - 61.4 Hz	90 min
	61.4 - 61.9 Hz	12 min
	61.9 - 62.4 Hz	1 min
	Generator abnormal frequency is not considered in fatigue evaluations, therefore cycle tracking is not required.	
29	Maximum Probable Earthquake (0.08g)	650 (2^{17})
	Documentation is not necessary due to large number of allowable transients.	
30	Pressurizer Spray Nozzle	25/25
	Temperature difference between the pressurizer spray line and pressurizer spray nozzle exceeding 300°F but below 400°F.	
31	Permanent Canal Seal Plate [2]	50 / 51
	The Permanent Canal Seal Plate installed in 13 RFO is qualified for a total of 50 heatup and cooldown cycles and 50 operating basis earthquakes.	
	Possible sources of information: Refer to transients 1A and 1B for RCS heatup and cooldown logging information.	
32	ROTSG Bolted Connections (Tension/Torque Cycles)[14]	100
	Primary Manways – 2 per ROTSG, 16 studs each. Normally removed at refueling outages.	
	Primary Handholes - 1 per ROTSG, 8 studs each. Normally removed at refueling outages.	
	Secondary Manways – 2 per ROTSG, 16 studs each	
	Secondary Handholes - 5 per ROTSG, 8 studs each	
	Secondary Inspection Ports (seal welded) – 32 per ROTSG, 6 studs each	
	Main Feedwater Nozzles (seal welded) – 32 per ROTSG, 8 studs each	
	Auxiliary Feedwater Nozzles (seal welded) - 8 per ROTSG, 8 studs each	
33	RCP seal cavity flexible hoses	15 (each hose)

ATTACHMENT 1: DESCRIPTION OF TRANSIENTS

Footnotes:

1. USAR Table 5.1-8 includes thermal design cycles only. Component design calculations also consider mechanical loads including 650 cycles of the maximum probable earthquake (aka, Operational Basis Earthquake); the reactor cavity seal plate is designed for 50 OBE cycles.
2. Reactor cavity seal plate limited to 50 HU/CD cycles.
3. ASME Classification is Emergency and is not required to be considered for calculation of peak stress and cumulative usage (ASME III, NB-3224.4).
4. Transient cycles not counted due to large number of design cycles.
5. Auxiliary feedwater bolted nozzles limit no longer applicable with ROTSG
6. For reactor vessel head vent line only.
7. Primary side: ≤200 °F, 0 - 485 psig; Secondary side: ≥140 °F, 0 psig; Feedwater: 50 - 225 °F
8. Primary side: ≤120 °F, 0 - 485 psig; Secondary side: ≥60 °F, 0 psig; Feedwater: 50 - 225 °F
9. Primary fill water: 50 °F, 0 psig; Secondary side: 140 °F, 0 psig
10. Primary fill water: 140 °F, 0 psig; Secondary side: 50 °F, 0 psig
11. Transient is not counted as it is not a fatigue significant event.
12. Transient is not applicable to Davis-Besse. High pressure injection pumps recirculate back to the Borated Water Storage Tank during the High Pressure Injection System Test and therefore, no inventory is added to the Reactor Coolant System..
13. The significant transients which affect the restrictor and weld of the core flood nozzles are heatup and cooldown (transient numbers 1A and 1B), core flooding system periodic test (transient number 22B), and decay heat removal (DHR) swapping (transient number 25). For transient number 25, the transient cycles are not counted. The DHR Swapping Transient was established to address historical practices related to the DHR train swap. Current Davis-Besse procedures dictate that the RCPs are run during plant cooldown to approximately 160°F RCS temperature. The DHR trains are not swapped until the RCS temperature has been significantly reduced and therefore, a DHR Swapping Transient does not occur.
14. There is a maximum of 100 bolt preload (tensioning or torqueing) cycles for all ROTSG bolted openings including the primary manways, primary handholes, secondary manways, secondary handholes, secondary inspection ports and main and auxiliary feedwater nozzles per the B&W ROTSG O&M Manual. Ten cycles are assumed on each stud up to assembly for initial operation.
15. The ROTSGs experienced one hydrostatic test for the Primary Side and one hydrostatic test for the secondary side at the Babcock & Wilcox facility in Cambridge Ontario.
16. 60 year projected cycles and basis is documented in Letter L-11-166, Table 4.3-1. Best estimate for heatups and cooldowns is documented in Letter L-11-203.
17. Transients 11, 18 and 29 have not occurred, therefore two occurances of these transients was used to evaluate several locations for EAF. (Reference C-ME-099.20-007).

ATTACHMENT 2: AOTC EVENT LOG

Page 1 of 1

DAVIS-BESSE UNIT 1

Description of Events (Be Specific as Possible)	AOTC No.	No. of Cycles	Relevant Reports or Other Info.	Date

ATTACHMENT 3: AOTC STATUS LOG

Date___________________________________

Previous Report Date______________________

Transient Number, Transient Title	Events This Period	Total Events∗	Limit	Estimated Date to Reach Limit
1A - Heatup from 70°F to 8% Full Power			114	
1B - Cooldown from 8% Full Power			114	
1C - Natural Circulation Cooldown			2	
2 - Power Change 0 to 15% and 15% to 0%			205 94	0 to 15% 15 to 0%
3 - Power Loading 8% to 100%	N/A	N/A	1,800	N/A
4 - Power Unloading 100% to 8%	N/A	N/A	1,800	N/A
5 - 10% Power Step Load Increase			67	
6 - 10% Power Step Load Decrease			140	
7 - Step Load Reduction (100 to 8%)	---	---	---	---
7A - Resulting from Turbine Trip			8	
7B - Resulting from Elec. Load Rejection			4	
8 - Reactor Trip	---	---	---	---
8A - Low RC flow directly causes Rx trip			4	
8B - High RC outlet temperature, high RC pressure or overpower trip - assumes a turbine trip occurs without automatic control system action			47	
8C - High RC pressure resulting from loss of feedwater			26	
8D - Other Trips (see Attachment 1)			110	
8E – Similar to 8A but RC Pumps are tripped (Emergency)			20	

NOTE: Refer to procedure body for columns marked N/A , ∗ Since initial criticality 8/12/77

ATTACHMENT 3: AOTC STATUS LOG

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Date____________________________________

Previous Report Date______________________

Transient Number, Transient Title	Events This Period	Total Events∗	Limit	Estimated Date to Reach Limit
9 - Rapid Depressurizations	---	---	---	---
9A – Rapid RCS Depressurization			4	
9B – Rapid Depressurization, trip RC Pumps			10	
10 - Change of reactor coolant flow (typical change of flow transient is loss of one RCP) without Reactor Trip			10	
11 - Rod Withdrawl Accident			1	
12 - Hydrotest	---	---	---	---
12A – RCS Components Except ROTSG and Replacement RCS Piping (Flowmeter to ROTSG) (includes 5 shop tests)			9	
12B – ROTSG and Replacement RCS PIPING (Flowmeter to ROTSG) (includes 1 shop test)			3	
13 - Deleted (formerly Steady State Power Variations)	N/A	N/A	N/A	N/A
14 - Control Rod Drop			18	
15 - Loss of Station Power			6	
16 - Steam Line Failure			1	
17 - Steam Generator Boiling Dry	---	---	---	---
17A – Loss of feedwater to one steam generator			6	
17B – Stuck open turbine bypass valve			N/A	
18 - Loss of Feedwater Heater			1	

NOTE: Refer to procedure body for columns marked N/A., ∗ Since initial criticality 8/12/77

ATTACHMENT 3: AOTC STATUS LOG

Date____________________________________

Previous Report Date_______________________

<table>
<tr><th>Transient Number, Transient Title</th><th colspan="2">Events This Period</th><th colspan="2">Total Events∗</th><th colspan="2">Limit</th><th colspan="2">Estimated Date to Reach Limit</th></tr>
<tr><td>19 - Feed and Bleed Operations</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">4,000</td><td colspan="2">N/A</td></tr>
<tr><td>20 - Makeup and Pressurizer Spray Transients</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td></tr>
<tr><td>20A – Makeup Flow Transient 1</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">30,000</td><td colspan="2">N/A</td></tr>
<tr><td>20B – Makeup Flow Transient 2</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">$4X10^6$</td><td colspan="2">N/A</td></tr>
<tr><td>20C – Spray Valve/Pressurizer Spray Nozzle</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">20,000</td><td colspan="2">N/A</td></tr>
<tr><td>21 - Loss of Coolant Accident (LOCA)</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">1</td><td colspan="2"></td></tr>
<tr><td>22 - Test Transients</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td></tr>
<tr><td>22A1 – High Pressure Injection System</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">40</td><td colspan="2">N/A</td></tr>
<tr><td rowspan="4">22A2 – HPI System Pressure Isolation Integrity Test (See Attachment 1)</td><td>1-1</td><td>1-2</td><td>1-1</td><td>1-2</td><td>1-1</td><td>1-2</td><td>1-1</td><td>1-2</td></tr>
<tr><td></td><td></td><td></td><td></td><td>40</td><td>40</td><td></td><td></td></tr>
<tr><td>2-1</td><td>2-2</td><td>2-1</td><td>2-2</td><td>2-1</td><td>2-2</td><td>2-1</td><td>2-2</td></tr>
<tr><td></td><td></td><td></td><td></td><td>44</td><td>48</td><td></td><td></td></tr>
<tr><td>22B - Core Flooding Check Valve 1-1</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">26</td><td colspan="2"></td></tr>
<tr><td>22B - Core Flooding Check Valve 1-2</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">26</td><td colspan="2"></td></tr>
<tr><td>23 - Steam Generator Filling, Draining, Flushing and Cleaning</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td></tr>
<tr><td>23A – Steam Generator Secondary Side Filling</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td></tr>
<tr><td>Condition 1</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">120</td><td colspan="2">N/A</td></tr>
<tr><td>Condition 2</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">120</td><td colspan="2">N/A</td></tr>
<tr><td>23B – Steam Generator Primary Side Filling</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">---</td></tr>
<tr><td>Condition 1</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">120</td><td colspan="2">N/A</td></tr>
<tr><td>Condition 2</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">120</td><td colspan="2">N/A</td></tr>
</table>

NOTE: Refer to procedure body for columns marked N/A , ∗ Since initial criticality 8/12/77

ATTACHMENT 3: AOTC STATUS LOG

Date____________________________________

Previous Report Date_______________________

Transient Number, Transient Title	Events This Period	Total Events*	Limit	Estimated Date to Reach Limit
23C – Steam Generator Flush	N/A	N/A	20	N/A
23D – Steam Generator Chemical Cleaning	N/A	N/A	20	N/A
24 - Hot Functional Testing	0	1	1	8/9/77
25 - Decay Heat Removal Swapping Transient	N/A	N/A	20	N/A
26 - Pressurizer Heaters	---	---	---	---
26A - Design life at full capacity with 5,000 cycles is 10,000 hours.	N/A	N/A	5000	N/A
26B - Design life at full capacity with 20,000 cycles is 2,500 hours.	N/A	N/A	20,000	N/A
27 - Pressurizer Relief Valves [(a)]	---	---	---	---
27A - Code Relief Operation (RC13A, RC13B)			30[(b)]	
27B - Electromatic Relief (PORV) [(c)]	---	---	---	---
Condition 1 Temp ≥400°F**			96	
Condition 2 Temp < 400°F**			25	

(a)These limits temperature/cycles are due to thermal/structural restraints on the pressurizer safety valve lines and welds and not on design limitations on valves.

(b)This is the original limit determined when a loop seal existed on the discharge piping. Detailed analysis has not been performed following relocation of the valves and piping, but the new value will not be lower.

(c) If the valve cycles, the following information shall be recorded in the description section of the AOTC EVENT LOG (Attachment 2):

A)The number of lifts

B)The time between lifts

C)The upstream piping temperature prior to actuation (computer point T772).

NOTE: Refer to procedure body for columns marked N/A, * Since initial criticality 8/12/77

**PORV cycles since construction/startup 9/3/76 - CR 04-05690 evaluated need to re-evaluate 25 cycle limit for cycles <400°F, no reevaluation warranted.

ATTACHMENT 3: AOTC STATUS LOG

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Date_________________________________

Previous Report Date____________________

<table>
<tr><th>Transient Number, Transient Title</th><th colspan="2">Events This Period</th><th colspan="2">Total Events*/#</th><th colspan="2">Limit</th><th colspan="2">Estimated Date to Reach Limit</th></tr>
<tr><td>28 - Generator Operation Abnormal Frequency</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">See Attachment 1 for details</td><td colspan="2"></td></tr>
<tr><td>29 - Maximum Probable Earthquake (0.08g)</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">2</td><td colspan="2">N/A</td></tr>
<tr><td>30 - Pressurizer Spray Nozzle</td><td colspan="2"></td><td colspan="2">+3-estimate</td><td colspan="2">25</td><td colspan="2"></td></tr>
<tr><td rowspan="2">31 - Permanent Canal Seal Plate</td><td>HU/CD</td><td>OBE</td><td>HU/CD</td><td>OBE</td><td>HU/CD</td><td>OBE</td><td>HU/CD</td><td>OBE</td></tr>
<tr><td></td><td></td><td></td><td></td><td>50</td><td>50</td><td></td><td></td></tr>
<tr><td>32 - ROTSG Bolted Connections Torque – Tension Cycles</td><td colspan="2"></td><td colspan="2">#Events since ROTSG installation 10 base cycles assumed.</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #1</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #2</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #3</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #4</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #5</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #6</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #7</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #8</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #9</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #10</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #11</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
<tr><td>ROTSG 1-1 Upper Primary Manway – Stud #12</td><td colspan="2"></td><td colspan="2"></td><td colspan="2">100</td><td colspan="2"></td></tr>
</table>

NOTE: Refer to procedure body for columns marked N/A, * Since initial criticality 8/12/77

ATTACHMENT 3: AOTC STATUS LOG

Date____________________________________

Previous Report Date______________________

32 - ROTSG Bolted Connections Torque – Tension Cycles (continued)	Events This Period	#Events since ROTSG installation 10 base cycles assumed.	Limit	Estimated Date to Reach Limit
ROTSG 1-1 Upper Primary Manway – Stud #13			100	
ROTSG 1-1 Upper Primary Manway – Stud #14			100	
ROTSG 1-1 Upper Primary Manway – Stud #15			100	
ROTSG 1-1 Upper Primary Manway – Stud #16			100	
ROTSG 1-1 Lower Primary Manway – Stud #1			100	
ROTSG 1-1 Lower Primary Manway – Stud #2			100	
ROTSG 1-1 Lower Primary Manway – Stud #3			100	
ROTSG 1-1 Lower Primary Manway – Stud #4			100	
ROTSG 1-1 Lower Primary Manway – Stud #5			100	
ROTSG 1-1 Lower Primary Manway – Stud #6			100	
ROTSG 1-1 Lower Primary Manway – Stud #7			100	
ROTSG 1-1 Lower Primary Manway – Stud #8			100	
ROTSG 1-1 Lower Primary Manway – Stud #9			100	
ROTSG 1-1 Lower Primary Manway – Stud #10			100	
ROTSG 1-1 Lower Primary Manway – Stud #11			100	
ROTSG 1-1 Lower Primary Manway – Stud #12			100	
ROTSG 1-1 Lower Primary Manway – Stud #13			100	
ROTSG 1-1 Lower Primary Manway – Stud #14			100	
ROTSG 1-1 Lower Primary Manway – Stud #15			100	
ROTSG 1-1 Lower Primary Manway – Stud #16			100	
ROTSG 1-2 Upper Primary Manway – Stud #1			100	

ATTACHMENT 3: AOTC STATUS LOG
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Date____________________________________
Previous Report Date______________________

32 - ROTSG Bolted Connections Torque – Tension Cycles (continued)	Events This Period	#Events since ROTSG installation 10 base cycles assumed.	Limit	Estimated Date to Reach Limit
ROTSG 1-2 Upper Primary Manway – Stud #2			100	
ROTSG 1-2 Upper Primary Manway – Stud #3			100	
ROTSG 1-2 Upper Primary Manway – Stud #4			100	
ROTSG 1-2 Upper Primary Manway – Stud #5			100	
ROTSG 1-2 Upper Primary Manway – Stud #6			100	
ROTSG 1-2 Upper Primary Manway – Stud #7			100	
ROTSG 1-2 Upper Primary Manway – Stud #8			100	
ROTSG 1-2 Upper Primary Manway – Stud #9			100	
ROTSG 1-2 Upper Primary Manway – Stud #10			100	
ROTSG 1-2 Upper Primary Manway – Stud #11			100	
ROTSG 1-2 Upper Primary Manway – Stud #12			100	
ROTSG 1-2 Upper Primary Manway – Stud #13			100	
ROTSG 1-2 Upper Primary Manway – Stud #14			100	
ROTSG 1-2 Upper Primary Manway – Stud #15			100	
ROTSG 1-2 Upper Primary Manway – Stud #16			100	
ROTSG 1-2 Lower Primary Manway – Stud #1			100	
ROTSG 1-2 Lower Primary Manway – Stud #2			100	
ROTSG 1-2 Lower Primary Manway – Stud #3			100	
ROTSG 1-2 Lower Primary Manway – Stud #4			100	
ROTSG 1-2 Lower Primary Manway – Stud #5			100	
ROTSG 1-2 Lower Primary Manway – Stud #6			100	

ATTACHMENT 3: AOTC STATUS LOG

32 - ROTSG Bolted Connections Torque – Tension Cycles (continued)	Events This Period	#Events since ROTSG installation 10 base cycles assumed.	Limit	Estimated Date to Reach Limit
ROTSG 1-2 Lower Primary Manway – Stud #7			100	
ROTSG 1-2 Lower Primary Manway – Stud #8			100	
ROTSG 1-2 Lower Primary Manway – Stud #9			100	
ROTSG 1-2 Lower Primary Manway – Stud #10			100	
ROTSG 1-2 Lower Primary Manway – Stud #11			100	
ROTSG 1-2 Lower Primary Manway – Stud #12			100	
ROTSG 1-2 Lower Primary Manway – Stud #13			100	
ROTSG 1-2 Lower Primary Manway – Stud #14			100	
ROTSG 1-2 Lower Primary Manway – Stud #15			100	
ROTSG 1-2 Lower Primary Manway – Stud #16			100	
ROTSG 1-1 Primary Handhole – Stud #1			100	
ROTSG 1-1 Primary Handhole – Stud #2			100	
ROTSG 1-1 Primary Handhole – Stud #3			100	
ROTSG 1-1 Primary Handhole – Stud #4			100	
ROTSG 1-1 Primary Handhole – Stud #5			100	
ROTSG 1-1 Primary Handhole – Stud #6			100	
ROTSG 1-1 Primary Handhole – Stud #7			100	
ROTSG 1-1 Primary Handhole – Stud #8			100	
ROTSG 1-2 Primary Handhole – Stud #1			100	
ROTSG 1-2 Primary Handhole – Stud #2			100	
ROTSG 1-2 Primary Handhole – Stud #3			100	
ROTSG 1-2 Primary Handhole – Stud #4			100	

ATTACHMENT 3: AOTC STATUS LOG

32 - ROTSG Bolted Connections Torque – Tension Cycles (continued)	Events This Period	#Events since ROTSG installation 10 base cycles assumed.	Limit	Estimated Date to Reach Limit
ROTSG 1-2 Primary Handhole – Stud #5			100	
ROTSG 1-2 Primary Handhole – Stud #6			100	
ROTSG 1-2 Primary Handhole – Stud #7			100	
ROTSG 1-2 Primary Handhole – Stud #8			100	
ROTSG 1-1 Upper Secondary Manway Studs (16)			100	
ROTSG 1-1 Lower Secondary Manway Studs (16)			100	
ROTSG 1-2 Upper Secondary Manway Studs (16)			100	
ROTSG 1-2 Lower Secondary Manway Studs (16)			100	
ROTSG 1-1 Secondary Handhole 1 (uppermost) Studs (8)			100	
ROTSG 1-1 Secondary Handhole 2 Studs (8)			100	
ROTSG 1-1 Secondary Handhole 3 Studs (8)			100	
ROTSG 1-1 Secondary Handhole 4 Studs (8)			100	
ROTSG 1-1 Secondary Handhole 5 (lowermost) Studs (8)			100	
ROTSG 1-2 Secondary Handhole 1 (uppermost) Studs (8)			100	
ROTSG 1-2 Secondary Handhole 2 Studs (8)			100	
ROTSG 1-2 Secondary Handhole 3 Studs (8)			100	
ROTSG 1-2 Secondary Handhole 4 Studs (8)			100	

ATTACHMENT 3: AOTC STATUS LOG

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32 - ROTSG Bolted Connections Torque – Tension Cycles (continued)	Events This Period	#Events since ROTSG installation 10 base cycles assumed.	Limit	Estimated Date to Reach Limit
ROTSG 1-2 Secondary Handhole 5 (lowermost) Studs (8)			100	
ROTSG 1-1 Secondary Inspection Ports (32 per SG, 6 studs per port)			100	
ROTSG 1-2 Secondary Inspection Ports (32 per SG, 6 studs per port)			100	
ROTSG 1-1 Main Feedwater Nozzles. (32 nozzles per ROTSG, 8 studs per nozzle)			100	
ROTSG 1-2 Main Feedwater Nozzles. (32 nozzles per ROTSG, 8 studs per nozzle)			100	
ROTSG 1-1 Auxiliary Feedwater Nozzles (8 nozzles per ROTSG, 8 studs per nozzle)			100	
ROTSG 1-2 Auxiliary Feedwater Nozzles (8 nozzles per ROTSG, 8 studs per nozzle)			100	

Prepared:____________________ Date:__________ Reviewed:____________________Date:__________