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DTE Energy

10 CFR 54

April 27, 2015
NRC-15-0044

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington D C 20555-0001

References: 1) Fermi 2
NRC Docket No. 50-341
NRC License No. NPF-43

2) DTE Electric Company Letter to NRC, "Fermi 2 License Renewal Application," NRC-14-0028, dated April 24, 2014 (ML14121A554)

3) NRC Letter, "Requests for Additional Information for the Review of the Fermi 2 License Renewal Application – Set 27 (TAC No. MF4222)," dated March 26, 2015 (ML15077A108)

4) NRC Letter, "Requests for Additional Information for the Review of the Fermi 2 License Renewal Application – Set 28 (TAC No. MF4222)," dated March 26, 2015 (ML15078A337)

5) NRC Letter, "Requests for Additional Information for the Review of the Fermi 2 License Renewal Application – Set 29 (TAC No. MF4222)," dated March 26, 2015 (ML15082A046)

6) NRC Letter, "Requests for Additional Information for the Review of the Fermi 2 License Renewal Application – Set 31 (TAC No. MF4222)," dated April 2, 2015 (ML15085A513)

Subject: Response to NRC Request for Additional Information for the Review of the Fermi 2 License Renewal Application – Sets 27, 28, 29, and 31

In Reference 2, DTE Electric Company (DTE) submitted the License Renewal Application (LRA) for Fermi 2. In References 3, 4, 5, and 6, NRC staff requested additional information regarding the Fermi 2 LRA. Enclosure 1 to this letter provides the DTE response to the requests for additional information (RAIs).

One new commitment is being made in this submittal. The new commitment is in LRA Table A.4 Item 16, Inservice Inspection – IWF, as indicated in the response to RAI B.1.22-2a in Enclosure 1. In addition, a revision has been made to a commitment previously identified in the LRA. The revised commitment is in LRA Table A.4 Item 7, BWR Vessel Internals, as indicated in the response to RAI B.1.10-2 in Enclosure 1. Also, additional inspection and testing are being added to the One-Time Inspection Program and Periodic Surveillance and Preventive Maintenance Program regarding the suppression chamber spray piping and nozzles as indicated in the response to RAI 3.2.2.2-1a in Enclosure 1.

Should you have any questions or require additional information, please contact Lynne Goodman at 734-586-1205.

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

Executed on April 27, 2015

Vito A. Kaminskas
Site Vice President
Nuclear Generation

Enclosures: 1. DTE Response to NRC Request for Additional Information for the Review of the Fermi 2 License Renewal Application – Sets 27, 28, 29, and 31

cc: NRC Project Manager
NRC License Renewal Project Manager
NRC Resident Office
Reactor Projects Chief, Branch 5, Region III
Regional Administrator, Region III
Michigan Public Service Commission,
Regulated Energy Division (kindschl@michigan.gov)

Enclosure 1 to
NRC-15-0044

Fermi 2 NRC Docket No. 50-341
Operating License No. NPF-43

DTE Response to NRC Request for Additional Information for the Review of the Fermi 2 License Renewal Application – Sets 27, 28, 29, and 31

Set 27 RAI B.1.45-1

Background

As amended by letter dated February 5, 2015, License Renewal Application (LRA) Section B.1.45 states an exception to the "corrective actions" program element. The exception states that the high pressure coolant injection (HPCI) system lube oil reservoir internal coating will not be repaired or replaced and cites Nuclear Maintenance Applications Center Terry Turbine Users Group recommendations as a basis.

Issue

The staff noted that Electric Power Research Institute (EPRI) Technical Report (TR) 1007459, "Terry Turbine Maintenance Guide, HPCI Application," November 2002, Section 20.2.5, "Inspection and Maintenance," states, "[r]emove any damaged preservative paint coating. Do not attempt to repaint the surfaces of the oil reservoir." The exception states that coatings will not be replaced or repaired, while Technical Report 1007459 states that damaged preservative coatings should be removed. The staff does not take issue with the provision to not repaint the internal surfaces of the lube oil reservoir. However the staff lacks sufficient information to conclude that the HPCI turbine will be capable of performing its intended function if degraded coatings are present.

Request

State what actions would be taken to mitigate potential further degradation of degraded coatings on the internal surfaces of the HPCI system lube oil reservoir.

Response:

As stated in the Fermi 2 License Renewal Application (LRA) – Response to LR-ISG-2013-01 (NRC-15-0021), Fermi 2 utilizes the EPRI "Nuclear Maintenance Application Center: Terry Turbine Maintenance Guide, High Pressure Coolant Injection (HPCI) Application" as the basis for the HPCI Terry Turbine maintenance regime. In accordance with this guidance, defective, damaged, or degraded preservative paint coating will be removed.

LRA Revisions:

LRA Section B.1.45 is revised as shown below. Additions are shown in underline and deletions are shown in strike-through. Note that previous changes to this same LRA section made in the February 5, 2015 letter (NRC-15-0021) are not shown in underline or strike-through such that only the new changes due to RAI B.1.45-1 are shown as revisions.

B.1.45 COATING INTEGRITY

Exceptions to NUREG-1801

Element Affected	Exception
7. Corrective Actions	NUREG-1801 recommends that coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. The Fermi 2 High Pressure Coolant Injection System lube oil reservoir internal coating will not be replaced or repaired.[2]

Exception Notes

2. Fermi 2 is an active member of the Nuclear Maintenance Application Center (NMAC) Terry Turbine Users Group. Lessons learned and improved maintenance practices for the Terry Turbine have been communicated at industry meetings facilitated by NMAC's Terry Turbine Users Group and are incorporated in the High-Pressure Coolant Injection (HPCI) Maintenance Guide. This guide is the basis for the HPCI Terry Turbine maintenance regime at Fermi 2. With respect to the lube oil reservoir, the guide states that paint defects should be removed and the tank should not be recoated. In accordance with this guidance, defective, damaged, or degraded preservative paint coating will be removed.

Set 27 RAI B.1.45-2

Background

As amended by letter dated February 5, 2015, LRA Section B.1.45 states exceptions to the "corrective actions" program element. The exceptions state that when delamination, peeling, or blistering is detected during coating inspections and the coatings will be returned to service, physical testing will consist of lightly tapping the coating, light hand scraping, light power tool cleaning, or adhesion testing. The exception also states that destructive adhesion testing will not be conducted. The exception further states that longer followup and re-inspection inspection intervals than those recommended in Aging Management Program (AMP) XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," would be allowed as long as they were technically justified.

Issue

The "corrective actions" program element of AMP XI.M42 recommends that where adhesion testing is not possible due to physical constraints alternative means of physical testing such as those described by the applicant would be acceptable. However, the exception does not limit these alternative methods to instances where adhesion testing is not possible. There are nondestructive adhesion tests which can be conducted; therefore, the justification for the exception is not sufficient because it is based on the conclusion that coatings would be removed down to the base metal if adhesion testing is conducted. In addition, no basis was provided for inspection intervals beyond those recommended in the "~~acceptance criteria~~ corrective actions" program element of AMP XI.M42, beyond stating that a future evaluation would be conducted. [Per discussion with NRC on 4/7/15, the RAI should read as shown in strike-through/underline.]

Request

State: (a) why nondestructive adhesion testing cannot be performed when coatings are returned to service with delamination, peeling or blisters; (b) how lightly tapping the coating, light hand scraping, light power tool cleaning will be controlled (e.g., procedures, method qualification) such that consistent results can be obtained if nondestructive adhesion testing will not be performed; and (c) the basis and justification for any inspection intervals beyond those in the "~~acceptance criteria~~ corrective actions" program element of AMP XI.M42. [Per discussion with NRC on 4/7/15, the RAI should read as shown in strike-through/underline.]

Response:

a) If a corrective action evaluation determines that coatings can be returned to service with delamination, peeling or blisters, then destructive adhesion testing will not be performed. The use of nondestructive adhesion testing methods will be based on evaluation of the specific condition and the nondestructive testing method that would apply to that specific situation. Adhesion testing will not be performed if the method has been evaluated and

found to have the potential to cause unnecessary coating damage. For example, the use of ASTM test standard D4541 "Pull-Off Strength of Coatings Using Portable Adhesion Testers" requires the attachment of a test fixture to the coating using adhesive. If the subject coating passes the prescribed load test then the test fixture must be removed without damaging the coating. This is usually performed by shearing the test fixture off with a sharp blow from a hammer. This test fixture removal method may be inappropriate after a passed test as it is likely to damage the coating.

b) In the event that a suitable nondestructive adhesion test method cannot be applied, other methods of determining that the coating is suitable to return to service such as light tapping, light hand scraping, or light power tool cleaning will be used. These other methods will be incorporated into site procedures that shall conform to the provisions of applicable Society of Protective Coatings (SSPC) standards (e.g., SSPC-SP 2 Hand Tool Cleaning, SSPC-SP 3 Power Tool Cleaning, SSPC-SP 11 Power Tool Cleaning to Bare Metal, and Waterjet Cleaning SSPC-SP WJ-1,2,3, and 4). Per SSPC-SP 2 and SSPC-SP 3 these cleaning methods "remove all loose mill scale, loose rust, loose paint, and other loose detrimental foreign matter. It is not intended that adherent mill scale, rust, and paint be removed by this process. Mill scale, rust, and paint are considered adherent if they cannot be removed by lifting with a dull putty knife." Additionally, tap testing will be utilized. Although there is not an SSPC standard for tap testing, guidance is provided on this method in the EPRI Comprehensive Coatings Training Course. The EPRI Comprehensive Coatings Training Course will be incorporated into site training and qualification requirements for a Coating Specialist. Further, the tap testing guidance contained in the training course will be incorporated into site procedures.

c) Inspection intervals will be in accordance with the "corrective actions" program element of AMP XI.M42 such that follow-up visual inspections of coatings returned to service that do not meet acceptance criteria will be conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, and continuing at least once every two years until the degraded coating is repaired or replaced. Therefore, the associated portion of Exception 3 will be removed from LRA Section B.1.45.

In addition, DTE will exclude the mechanical draft cooling tower (MDCT) spray header assemblies from the Coatings Integrity Program (LRA Section B.1.45). The MDCT spray header assemblies consist of galvanized piping that distributes service water from plant safety-related cooling systems to a series of spray nozzles. The Division 1 and 2 MDCT consist of four cells, two in each division. The Service Water Integrity Program (LRA Section B.1.41) manages the effects of aging on the piping and spray nozzles. Preventive Maintenance (PM) events are in place to visually inspect and flow test each cell. All four cells are tested and inspected every 4.5 years (nominally every three refuel cycles) with one to two cell inspections scheduled each refuel cycle. The PM events require inspection of spray patterns to ensure no blockage. Spray nozzles that are found restricted or damaged during flow testing are cleaned out or replaced. Piping is replaced if cleaning is not practical. Results of the inspection are documented in the associated work package. Therefore, these Service Water Integrity Program activities will detect and

address loss of piping base material and downstream effects in the spray nozzles indicative of loss of coating integrity without the need for visual inspections under the Coatings Integrity Program.

LRA Revisions:

LRA Sections A.1.45 and B.1.45 and LRA Table 3.3.2-3 are revised as shown below. Additions are shown in underline and deletions are shown in strike-through. Note that previous changes to these same LRA sections made in the February 5, 2015 letter (NRC-15-0021) are not shown in underline or strike-through such that only the new changes due to RAI B.1.45-1 are shown as revisions.

Table 3.3.2-3
Service Water Systems
Summary of Aging Management Evaluation

Table 3.3.2-3: Service Water Systems								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of coating integrity	~~Coating Integrity~~ Service Water Integrity	--	--	H

A.1.45 Coating Integrity Program

The Coating Integrity Program is a new program that will include periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks where loss of coating or lining integrity could prevent accomplishment of a license renewal intended function. For coatings/linings that do not meet the acceptance criteria, physical testing is performed where possible (i.e., sufficient room to conduct testing) in conjunction with visual inspection. Hand tool cleaning and power tool cleaning will be controlled by site procedures that incorporate standards established by the Society of Protective Coatings (SSPC). Specifically, the standards include SSPC-SP 2 Hand Tool Cleaning, SSPC-SP 3 Power Tool Cleaning, and SSPC-SP 11 Power Tool Cleaning to Bare Metal. Further, where applicable, standards for water-jet cleaning will also be incorporated. These would include SSPC-SP WJ-1, 2, 3, and 4. Although there is not an SSPC standard for tap testing, guidance for tap testing is provided in the EPRI Comprehensive Coatings Training Course. This guidance will also be incorporated into site procedures. The training and qualification of individuals involved in inspections of non-cementitious coatings/linings are in accordance with ASTM standards endorsed in RG 1.54. In addition, the EPRI Comprehensive Coatings Training Course will be incorporated into site training and qualification requirements for a Coating Specialist. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Service Level 1 coatings are managed by the Protective Coating Monitoring and Maintenance Program (Section A.1.36).

B.1.45 COATING INTEGRITY

Program Description

The Coating Integrity Program is a new program that will include periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks where loss of coating or lining integrity could prevent accomplishment of a license renewal intended function. For coatings/linings that do not meet the acceptance criteria, physical testing is performed where possible (i.e., sufficient room to conduct testing) in conjunction with visual inspection. Hand tool cleaning and power tool cleaning will be controlled by site procedures that incorporate standards established by the Society of Protective Coatings (SSPC). Specifically, the standards include SSPC-SP 2 Hand Tool Cleaning, SSPC-SP 3 Power Tool Cleaning, and SSPC-SP 11 Power Tool Cleaning to Bare Metal. Further, where applicable, standards for water-jet cleaning will also be incorporated. These would include SSPC-SP WJ-1, 2, 3, and 4. Although there is not an SSPC standard for tap testing, guidance for tap testing is provided in the EPRI Comprehensive Coatings Training Course. This guidance will also be incorporated into site procedures. The training and qualification of individuals involved in inspections of non-cementitious coatings/linings are in accordance with ASTM standards endorsed in RG 1.54. In addition, the EPRI Comprehensive Coatings Training Course will be incorporated into site training and qualification requirements for a Coating Specialist. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Service Level 1 coatings are managed by the Protective Coating Monitoring and Maintenance Program (Section B.1.36).

B.1.45 COATING INTEGRITY

Exceptions to NUREG-1801

Element Affected	Exception
7. Corrective Actions	For coatings/linings exhibiting delamination and peeling that are returned to service, NUREG-1801 recommends physical testing~~,~~ and adhesion testing using ASTM International standards endorsed in RG 1.54~~, and follow-up inspections~~. In the Fermi 2 program, physical testing of delamination and peeling will consist of lightly tapping the coating, light hand scraping, or light power tool cleaning~~, or adhesion testing~~ when a suitable nondestructive adhesion test method cannot be applied. Destructive adhesion testing will not be conducted. ~~Follow-up inspection and re-inspection intervals will be in accordance with NUREG-1801 recommendations unless longer inspection intervals are technically justified.~~[3]

Exception Notes

3. It is preferable to leave delamination and peeling that has not progressed to the base material intact instead of removing the entire coating system down to bare metal. Some material protection will still be provided by the intact coating layers. This may also facilitate future repairs of the coating system in this location since a smaller number of coats would be required to achieve the desired dry film thickness. The performance of destructive adhesion testing may damage intact coating layers. ~~Follow-up visual inspections of damaged areas will be conducted within 2 years from detection of the degraded condition, with re-inspection within an additional 2 years, or until the degraded coating is repaired or replaced. In cases where equipment history is known and understood, extending inspections and re-inspections beyond the NUREG-1801 recommendations may be made with technical justification.~~

Element Affected	Exception
7. Corrective Actions	For blisters not repaired, NUREG-1801 recommends physical testing consisting of adhesion testing using ASTM International standards endorsed in RG 1.54. In the Fermi 2 program, for blisters not repaired, physical testing will consist of lightly tapping the coating, light hand scraping, or light power tool cleaning~~, or adhesion testing~~ when a suitable nondestructive adhesion test method cannot be applied. Destructive adhesion testing will not be conducted.[4]

Exception Notes

4. Destructive adhesion testing will remove potentially sound material surrounding a blister. Leaving this material intact will continue to provide some degree of protection. Additionally, the removal of sound coating material via destructive testing may increase the likelihood of base material degradation due to exposure.

Set 27 RAI B.1.45-3

Background

As amended by letter dated February 5, 2015, LRA Section A.1.45 provides the Updated Final Safety Analysis Report (UFSAR) supplement for the Coating Integrity Program. It states in part, "[b]aseline coating/lining inspections will occur in the 10-year period prior to the period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on in scope component intended functions, potential problems identified during prior inspections, and service life history."

Issue

The AMP XI.M42 "detection of aging effects" program element makes virtually the same statement; however, it expands on the statement by stating, "inspection intervals should not exceed that in Table 4a, 'Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.'" The staff noted that based on the proposed wording in the UFSAR supplement subsequent inspections may not occur on recommended intervals or may not occur at all.

Request

State and justify the criteria that will be used to determine the maximum duration between coating inspections.

Response:

The frequency of inspections for the Coating Integrity Program will be in accordance with Table 4a, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," of LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-scope Piping, Piping Components, Heat Exchangers, and Tanks." Therefore, License Renewal Application (LRA) Section A.1.45 will be revised to clarify that the inspection intervals in Table 4a of LR-ISG-2013-01 should not be exceeded.

LRA Revisions:

LRA Section A.1.45 is revised as shown below. Additions are shown in underline and deletions are shown in strike-through. Note that previous changes to this same LRA section made in the February 5, 2015 letter (NRC-15-0021) are not shown in underline or strike-through such that only the new changes due to RAI B.1.45-3 are shown as revisions.

A.1.45 Coating Integrity Program

Baseline coating/lining inspections will occur in the 10-year period prior to the period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on in-scope component intended functions, potential problems identified during prior inspections, and service life history, but should not exceed the inspection intervals in Table 4a "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers" identified in LR-ISG-2013-01.

Set 28 RAI B.1.10-2

Background

License Renewal Application (LRA) Commitment No. 7, Part c, in LRA Table A.4 provides activities that the applicant will need to complete in order to manage loss of preload due to stress relaxation in the plant's core plate rim hold-down bolts. By letter dated December 23, 2014, the staff issued request for additional information (RAI) 4.1-2, which relates to identification of the future aging analysis that will be performed in evaluation of the plant's core plate rim hold-down bolts and why that analysis would not need to be submitted to the staff for approval prior to the period of extended operation. By letter dated February 5, 2015, the applicant responded to RAI 4.1-2, which amended LRA Commitment No. 7, Part c, Option (b). Under this part of Commitment No. 7, the applicant will only be submitting an inspection plan to the staff for approval if the future Electric Power Research Institute (EPRI) Boiling Water Reactor Vessel and Internals Project (BWRVIP) inspection and evaluation (I&E) guideline bases for boiling water reactor (BWR) core plate rim hold-down bolts will continue to call for inspections of these components.

Issue

LRA Commitment No. 7, Part c, Option (b), as amended by letter dated February 5, 2015, does not constitute an adequate basis for managing loss of preload/stress relaxation in the core plate rim hold-down bolts because: (a) the proposed action in the option is based on the applicant's speculation that the BWRVIP will be updating its inspection guidance for core plate rim hold-down bolts, which has yet to be done (including proper regulatory review by the staff), and (b) the proposed action in the option does not indicate that the inspection plan for the core plate rim hold-down bolts, along with the supporting loss of preload/stress relaxation analysis and justification, will be submitted to the staff for approval at least two years prior to entering into the period of extended operation, regardless of whether inspections of the bolts will be implemented or eliminated in the updated I&E guidelines for the components.

Request

Justify why amended versions of LRA Commitment No. 7, Part c, Option (b), in LRA Table A.4 and LRA Section A.1.10 do not commit to submittal of an inspection plan for the core plate rim hold-down bolts, along with a supporting loss of preload/stress relaxation analysis and justification, for staff review and approval at least two years prior to entering into the period of extended operation, regardless of whether the submitted basis proposes inspections or justifies elimination of inspections for the core plate rim hold-down bolts.

Response:

BWR Vessel Internals Program Commitment 7c will be revised as follows.

In accordance with an applicant action item for BWRVIP-25 safety evaluation:

(a) install core plate wedges prior to the period of extended operation, or
(b) complete a plant-specific analysis that justifies no inspections are required, or
(c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25.

For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

LRA Revisions:

LRA Sections A.1.10, A.4, B.1.10, and C are revised as shown below. Additions are shown in underline and deletions are shown in strike-through. Note that previous changes to these same LRA sections made in the February 5, 2015 letter (NRC-15-0010) are not shown in underline or strike-through such that only the new changes due to RAI B.1.10-2 are shown as revisions.

A.1.10 BWR Vessel Internals Program

The BWR Vessel Internals Program will be enhanced as follows.

- BWR Vessel Internals Program procedures will be revised as follows. In accordance with an applicant action item for BWRVIP-25 safety evaluation: (a) install core plate wedges prior to the period of extended operation, or (b) complete a plant-specific analysis that justifies no inspections are required~~ or to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. The analysis will address loss of preload due to stress relaxation in the core plate rim holddown bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. If the analysis results in acceptance criteria for continued inspection, the inspection plan, along with the acceptance criteria and justification for the inspection plan, will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation~~, or (c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25.
  For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.
  For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

A.4 LICENSE RENEWAL COMMITMENT LIST

No.	Program or Activity	Commitment	Implementation Schedule	Source
7	BWR Vessel Internals	Enhance BWR Vessel Internals Program as follows: c. BWR Vessel Internals Program procedures will be revised as follows. In accordance with an applicant action item for BWRVIP-25 safety evaluation: (a) install core plate wedges prior to the period of extended operation, or (b) complete a plant-specific analysis that justifies no inspections are required~~ or to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. The analysis will address loss of preload due to stress relaxation in the core plate rim holddown bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. If the analysis results in acceptance criteria for continued inspection, the inspection plan, along with the acceptance criteria and justification for the inspection plan, will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation~~, or (c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of	Perform initial inspection either prior to March 20, 2025 or before March 20, 2030. Submit analysis and inspection plan to NRC prior to March 20, 2023. Remaining activities: Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	A.1.10

No.	Program or Activity	Commitment	Implementation Schedule	Source
		extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation. For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.		

B.1.10 BWR Vessel Internals

Enhancements

Element Affected	Enhancement
4. Detection of Aging Effects	BWR Vessel Internals Program procedures will be revised as follows. In accordance with an applicant action item for BWRVIP-25 safety evaluation: (a) install core plate wedges prior to the period of extended operation, or (b) complete a plant-specific analysis that justifies no inspections are required~~ or to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. The analysis will address loss of preload due to stress relaxation in the core plate rim holddown bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. If the analysis results in acceptance criteria for continued inspection, the inspection plan, along with the acceptance criteria and justification for the inspection plan, will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation~~, or (c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation. For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

Appendix C
Response to BWRVIP Applicant Action Items

Action Item Description	Response
BWRVIP-25 (4)	
Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	For BWRs that do not have core plate wedges, BWRVIP-25 recommends evaluation of two aging effects on the core support plate hold-down bolts: loss of preload and cracking. Fermi 2 is a BWR 4 without core plate wedges, so these aging effects apply and are evaluated as follows. Prior to the period of extended operation, Fermi 2 will enhance the BWR Vessel Internals Program (refer to Appendix B, Section B.1.10) to perform one of the following. • Install core plate wedges prior to the period of extended operation, or • Complete a plant-specific analysis that justifies no inspections are required~~ or to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. The analysis will address loss of preload due to stress relaxation in the core plate rim holddown bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. If the analysis results in acceptance criteria for continued inspection, the inspection plan, along with the acceptance criteria and justification for the inspection plan, will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.~~, or

	• Complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25. For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation. For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

Set 28 RAI 4.2.7-1

Background

LRA Section 4.2.7 describes the applicant's time-limited aging analysis (TLAA) evaluation for the reactor pressure vessel (RPV) core reflood thermal shock analysis. The LRA states that the analysis currently in effect is documented in General Electric (GE) Technical Report (TR) No. NEDO-10029, "An Analytical Study on Brittle Fracture of GE-BWR Vessels Subject to the Design Basis Accident," dated June 1969. The LRA also states that a later thermal shock analysis, "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," was developed by S. Ranganath in August 1979. The LRA explains that the Ranganath analysis bounds the Fermi 2 RPV considering the maximum adjusted reference temperature for the Fermi 2 RPV beltline materials at the end of the period of extended operation. Therefore, the LRA concludes that the RPV core reflood thermal shock analysis has been projected to the end of the period of extended operation.

Issue

1. *The analysis in TR No. NEDO-10029 represents the RPV core reflood thermal shock analysis that is currently in effect for the current licensing basis (CLB), not the 1979 Ranganath analysis. In addition, the 1979 Ranganath analysis was performed in analysis of a GE BWR-6 reactor design; however, the reactor at Fermi 2 is a GE BWR-4 reactor design. Therefore, the applicant has yet to demonstrate that the TLAA in LRA Section 4.2.7 is acceptable in accordance with either 10 CFR 54.21(c)(1)(ii) because the LRA does not identify: (a) which of the two RPV core reflood analysis reports, NEDO-10029 or the 1979 Ranganath analysis, will be relied upon for the period of extended operation, and (b) the limit on the end-of-life* RT_{NDT} *value that is established in the core reflood analysis that will be relied upon for the period of extended operation.*

2. *In addition, if the 1979 Ranganath analysis will be relied upon as the RPV core reflood analysis report for the period of extended operation, the staff would need further justification on the basis for using a report on a GE BWR-6 reactor design as the basis for the RPV at Fermi 2, which is a GE BWR-4 reactor design.*

Request

1. *Clarify which of the two RPV core reflood analysis (i.e., the NEDO-10029 report or the 1979 Ranganath analysis) will be used for the period of extended operation. Identify the limit that is placed on the end-of-life RTNDT value for the RPV core reflood analysis report that will be relied upon for the period of extended operation. Identify whether the specific limit is based on the inside surface location, RPV base metal-to-clad interface location, or 1/4T location of the RPV.*

2. *If the 1979 Ranganath analysis will be the report that is relied upon for the period of extended operation, justify the basis for applying the 1979 Ranganath report to the licensing basis for Fermi 2 during the period of extended operation, when the RPV at Fermi 2 is that for a GE BWR-4 reactor design. As part of this response demonstrate that the stress and neutron fluence levels assumed in the Ranganath analysis for the RPV in a BWR-6 reactor design are bounding for those that will apply to the RPV at Fermi 2 at the end of the period of extended operation (i.e., through 52 effective full power years [52 EFPY]).*

Response:

1. For the period of extended operation, the method addressed by S. Ranganath in "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979 (Accession No. 9110110105 in Public Legacy Library) was used to project the effects of core reflood after a postulated loss of coolant accident (LOCA). The 1979 Ranganath analysis does not specifically calculate a limit for reference nil ductility transition temperature, RT_{NDT}, for the reflood analysis. Instead, the analysis calculates the temperature distribution and thermal stress in the reactor vessel wall. The analysis then determined that temperature is high enough to ensure margin in the available fracture toughness at the time of maximum stress intensity after the LOCA. The time-limited aging analysis aspect of the evaluation is the use of the RT_{NDT} as adjusted for neutron fluence.

   The maximum stress intensity is shown to be applied approximately 300 seconds after the LOCA at approximately ¼ thickness (¼T) of the vessel. The temperature at ¼T is approximately 400°F at that time. The highest Fermi 2 adjusted reference temperature (ART) (referred to as the adjusted RT_{NDT} in the analysis) for ¼T shown in Tables 4.2-2 and 4.2-3 of the LRA is 102°F. This ART is for 52 EFPY, which bounds the expected 60-year license term of the plant. For Fermi 2, the temperature at which upper shelf transition would occur was calculated using Fermi 2's maximum ART in an equation for fracture toughness KIC presented in Appendix A of ASME Section XI. The Fermi 2 limiting material reaches upper shelf at approximately 206°F, which is well below the approximately 400°F temperature predicted at the time of peak stress intensity in the Ranganath analysis. The acceptance criterion to show that the vessel can withstand the stresses of the reflood thermal shock is that the upper shelf transition temperature is lower than the temperature at the time of maximum stress intensity. Since 206°F is considerably less than approximately 400°F, this criterion is met. Therefore, the revised evaluation, using the Ranganath analysis, has projected the core reflood thermal shock analysis through the period of extended operation.

2. The analysis by S. Ranganath was based on a 6-inch thick BWR-6 vessel. The thickness of the lower shell for the Fermi 2 vessel is 7.125 inches; the thickness of the lower-intermediate shell is 6.125 inches. The analysis is applicable to the Fermi 2 vessel because (1) the difference in temperature and thermal stresses at the ¼T location between a 6-inch thick BWR/6 vessel and a 6.125-inch or 7.125-inch thick vessel (as demonstrated in Figures 3 and

4 of the Ranganath analysis) is small, with the temperature higher and stresses lower at 300 seconds in the slightly thicker ¼T location and (2) the pressure stress (higher for a thinner vessel) is near zero in a thermal shock event and therefore can be neglected. The fluence level and ART values used are specific to Fermi 2, as projected for 52 EFPY, as documented in the LRA, Section 4.2.2. Also, there is significant margin in the analysis results.

LRA Revisions:

LRA Sections 4.2.7 and A.2.1.7 are revised as shown below. Additions are shown in underline and deletions are shown in strike-through.

4.2.7 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

General Electric Report NEDO-10029 (Ref. 4-5) is referenced in UFSAR Section A.1.2 and Table 1.6-1. NEDO-10029 addressed the concern for brittle fracture of the RPV due to reflood following a postulated loss of coolant accident (LOCA). The thermal shock analysis documented in NEDO-10029 assumed a design basis recirculation line break LOCA followed by a low pressure coolant injection, accounting for the full effects of neutron embrittlement at the end of 40 years. This analysis bounded only 40 years of operation; therefore, reflood thermal shock of the RPV has been identified as a TLAA for Fermi 2 requiring evaluation for the period of extended operation.

A later analysis of the BWR vessels was developed by S. Ranganath in 1979 (Ref. 4-11). The Ranganath analysis has been used to project the TLAA through the period of extended operation. The Ranganath analysis which was performed for a 6-inch thick BWR-6 pressure vessel is bounding for the Fermi 2 vessel. The thickness of the lower shell for the Fermi 2 vessel is 7.125 inches; the thickness of the lower-intermediate shell is 6.125 inches. The Ranganath analysis is bounding for Fermi 2 because (1) the pressure stress (higher for a thinner vessel) is near zero in a thermal shock event and therefore can be neglected, and (2) the difference in thermal stresses at the ¼T location between a 6-inch thick vessel and a 6.125-inch or 7.125-inch thick vessel (as demonstrated in Figures 3 and 4 of Ranganath) is small. The fluence level and ART values used are specific to Fermi 2, as projected for 52 EFPY. The analysis shows that when the peak stress intensity occurs at approximately 300 seconds after the LOCA, the temperature of the vessel wall at 1.5 inches deep is approximately 400°F.

The maximum ART value calculated for the Fermi 2 RPV beltline material is 102°F. Using the equation for fracture toughness KIC presented in Appendix A of ASME Section XI and the maximum ART value, the material reaches upper shelf at approximately 206~~.25~~°F, which is well below the approximately ~~minimum~~ 400°F temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the revised evaluation, using the Ranganath analysis, has projected the TLAA through the period of extended operation.

The RPV core reflood thermal shock TLAA has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.1.7 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

General Electric Report NEDO-10029 is referenced in UFSAR Section A.1.2 and Table 1.6-1. NEDO-10029 addressed the concern for brittle fracture of the reactor pressure vessel due to reflood following a postulated loss of coolant accident (LOCA). The thermal shock analysis documented in NEDO-10029 assumed a design basis recirculation line break LOCA followed by a low pressure coolant injection, accounting for the full effects of neutron embrittlement at the end of 40 years. Because this analysis bounded only 40 years of operation, reflood thermal shock of the reactor pressure vessel has been identified as a TLAA for Fermi 2 requiring evaluation for the period of extended operation.

A later analysis of the BWR vessels was developed in 1979 (Ranganath, S., "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979 (Accession No. 9110110105 in Public Legacy Library)). The Ranganath analysis has been used to evaluate the TLAA through the period of extended operation. The Ranganath analysis which was performed for a 6-inch thick BWR-6 pressure vessel is bounding for the Fermi 2 vessel. The thickness of the lower shell for the Fermi 2 vessel is 7.125 inches; the thickness of the lower-intermediate shell is 6.125 inches. The Ranganath analysis is bounding for Fermi 2 because (1) the pressure stress (higher for a thinner vessel) is near zero in a thermal shock event and therefore can be neglected, and (2) the difference in temperature and thermal stresses at the ¼T location between a 6-inch thick vessel and a 6.125-inch or 7.125-inch thick vessel (as demonstrated in Figures 3 and 4 of Ranganath) is small. The fluence level and ART values used are specific to Fermi 2, as projected for 52 EFPY. The analysis shows that when the peak stress intensity occurs at approximately 300 seconds after the LOCA, the temperature of the vessel wall at 1.5 inches deep is approximately 400°F.

The maximum ART value calculated for the Fermi 2 RPV beltline material is 102°F. Using the equation for fracture toughness KIC presented in Appendix A of ASME Section XI and the maximum ART value, the material reaches upper shelf at approximately 206~~.25~~°F, which is well below the approximately ~~minimum~~ 400°F temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the revised evaluation, using the Ranganath analysis, has projected the TLAA through the period of extended operation. The reactor pressure vessel core reflood thermal shock TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

Set 29 RAI B.1.22-2a

Background

By letter dated December 19, 2014, the staff issued Request for Additional Information (RAI) B.1.22-2 requesting DTE to describe how the Inservice Inspection - IWF Program will continue to be effective when corrective actions are not required per the ASME Code, Section XI, Subsection IWF-2430, but a component in the IWF inspection sample is re-worked such that it no longer represents age-related degradation of the entire population. In response to RAI B.1.22-2 dated January 20, 2015, DTE stated, in part, the following:

> *Correction of some conditions over the life of the plant is expected but will not impair the ability of the IWF Program to manage the effects of aging. Modifying the program to add new component locations when a condition has been addressed is not necessary. This is because the aging mechanisms will likely be caused by local environment or operational conditions such as vibration or humidity. The programmatic requirements for sample expansion or extent of condition will address that. The Code sample population size is large enough that correction of some conditions will not prevent the program from adequately managing the effects of aging.*

Issue

NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Appendix A.1, recommends that when sampling is used to represent a larger population of components the sample should be based on aspects such as similarity of material, environment, and specific aging effect. The staff concern is that re-worked to as new condition IWF components are no longer representative of the specific age-related degradation of those IWF components in the population that are not in the inspection sample.

Request

Explain how the Inservice Inspection - IWF Program will ensure that the inspection sample will adequately represent the age-related degradation of the IWF component population when components that are part of the sample are re-worked and no longer represent the age-related degradation of the remaining population.

Response:

The Inservice Inspection – IWF Program will be enhanced to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked. The revisions to the License Renewal Application (LRA) are indicated below.

LRA Revisions:

LRA Sections A.1.22, A.4, and B.1.22 are revised as shown on the following pages. Additions are shown in underline and deletions are shown in strike-through.

A.1.22 <u>Inservice Inspection – IWF Program</u>

The ISI-IWF Program will be enhanced as follows.

- Revise plant procedures to identify the following unacceptable conditions:
  - Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.
  - Cracked or sheared bolts, including high-strength bolts, and anchors.
- <u>Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.</u>

Enhancements will be implemented prior to the period of extended operation.

A.4 LICENSE RENEWAL COMMITMENT LIST

No.	Program or Activity	Commitment	Implementation Schedule	Source
16	Inservice Inspection (ISI) – IWF	Enhance ISI-IWF Program as follows: g. Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.	Prior to September 20, 2024.	A.1.22

B.1.22 INSERVICE INSPECTION – IWF

Enhancements

Element Affected	Enhancement
4. Detection of Aging Effects	Revise plant procedures to specify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts.
5. Monitoring and Trending	Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.
6. Acceptance Criteria	Revise plant procedures to identify the following unacceptable conditions: • Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support. • Cracked or sheared bolts, including high-strength bolts, and anchors.

Set 29 RAI 3.2.2.2-1a

Background

By letter dated February 5, 2015, DTE responded to an initial RAI regarding spray nozzles in the reactor heat removal (RHR) system, which are being managed by the Water Chemistry – BWR Program. For the drywell spray headers, the response confirms that the portions inside the drywell are not safety-related and there is no flow control function for the associated spray nozzles. For the suppression chamber spray nozzles, the response states that the suppression pool is inerted to less than 4 percent oxygen during power operation which reduces the potential for corrosion. The response also describes the quarterly surveillance test on the suppression chamber spray system and states that greater-than-minimum flow rates were achieved during every surveillance test for the last 4 years. The response also states that if significant blockage were to develop, the flow rates through the suppression chamber spray header would indicate a decreasing trend. In addition, the response describes the 5-year surveillance test that verifies the drywell spray nozzles are unobstructed. With respect to aging management activities for the suppression chamber piping and spray nozzles, the response states that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry – BWR Program and that the internal environment of the spray header is considered treated water. The response concludes that the license renewal application (LRA) did not need to be revised.

Issue

As noted in the initial RAI, the LRA defines "flow control" as "provide control of flow rate or establish a pattern of spray." The RHR system spray nozzles in LRA Table 3.2.2-2, which show an intended function of "flow control," only list "loss of material" as the aging effect requiring management. While the staff recognizes that loss of material in a spray nozzle may affect its spray pattern, loss of material would only tend to allow higher flow rates, and the RAI response does not include any discussion regarding activities to monitor nozzle spray patterns. Verifying the total flow into the suppression chamber does not confirm "flow control" for individual nozzles. Based on the RAI response, it remains unclear to the staff how only managing "loss of material" will address the "flow control" function for individual spray nozzles due to potential plugging from corrosion products. The staff notes that for other aging management review (AMR) items, the LRA includes "fouling" as an aging effect requiring management, while the Generic Aging Lessons Learned (GALL) Report considers "fouling" as an aging mechanism. As it relates to nozzle plugging, the staff considers "fouling" to be an appropriate aging effect.

The staff notes that containment inerting to less than 4 percent oxygen appears to be the only basis provided in the RAI response that relates to a lack of corrosion product accumulation due to periodic wetting and drying of upstream steel piping. Although the inerted atmosphere may reduce the amount of corrosion, the staff concludes that there is still sufficient oxygen to support ongoing general corrosion in the steel piping upstream of the nozzles. In addition, a relatively low level of oxygen in the water within the system is sufficient to cause ongoing corrosion issues within the suppression pool or attached steel piping. The staff notes the operating experience

included in the Fitzpatrick license renewal safety evaluation report (ADAMS Accession No. ML080250372) discusses blockage in some spray nozzles found during past surveillance tests. Based on the above, the response did not provide sufficient bases to establish that corrosion product accumulation from upstream steel piping cannot cause flow blockage in the suppression chamber nozzles.

In its review of the response, the staff notes that blockage for the suppression chamber spray nozzles is to some degree being managed through various surveillance activities. However, the only program credited in the LRA for the nozzles is the Water Chemistry Control – BWR Program, which does not include these surveillance activities. In addition, activities in the One-Time Inspection Program to confirm the effectiveness of the Water Chemistry Control – BWR Program, only include fouling as it relates to reduction of heat transfer and do not address fouling as it relates to plugging of spray nozzles.

The staff also notes that the One-Time Inspection Program currently includes inspections of internal and external surfaces of the piping in several systems that pass through the waterline region of the suppression pool. However, neither the suppression pool spray piping nor the spray nozzles are included in those activities. In that regard, the internal surfaces of the suppression pool spray piping are different than most other piping surfaces because they are periodically wetted during surveillance activities, but portions of the system will drain between tests and the inside surfaces will be exposed to the suppression pool atmosphere. Consequently, it is not clear to the staff whether the suppression pool spray header piping will be considered as a unique internal environment from other piping that remains filled with treated water. As discussed in NRC Information Notice 2013-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction," piping systems filled with water or kept completely dry are not as susceptible to internal corrosion as piping partially filled with water and air; however, even a properly designed system is susceptible to corrosion when it is filled with water numerous times because of testing. The staff acknowledges that this information notice only addressed fire water system piping, but there may be some commonality with potential problems in the suppression pool spray piping.

If the current suppression chamber spray header surveillances will be credited, then several additional aspects may need to be addressed. Although the initial RAI response states that a decreasing trend in the suppression chamber spray header flow rate would indicate the development of flow blockage, it is not clear to the staff that the current surveillance activities include trending of the spray header flow rates in order to identify this type of degradation. In addition, it is not clear to the staff that only trending of the flow rate through the spray header would be sufficient to identify flow blockage. Unless individual spray nozzles are being verified to be unobstructed (which, based on DTE's RAI response, is performed for the nonsafety-related drywell spray nozzles that do not require aging management), it is not clear to the staff how other activities can demonstrate that the effects of aging will be adequately managed so that the "flow control" intended function of the spray nozzles will be maintained during the period of extended operation, consistent with the current licensing basis.

Request

1. *Provide the bases to demonstrate that fouling does not need to be managed for the suppression chamber spray nozzles in order to adequately maintain the "flow control" intended function of the spray nozzles during the period of extended operation, consistent with the current licensing basis. As an alternative, provide an appropriate AMR item that addresses the aging effects associated with the spray nozzle "flow control" intended function. If applicable, include a description of the associated aging management activities that are either an enhancement to an existing program or a plant-specific aging management program. If flow rate is the only parameter that will be monitored, provide the acceptance criteria for the flow rate trend with supporting bases to demonstrate that the intended function of the spray nozzles will be maintained during the period of extended operation, consistent with the current licensing basis.*

2. *Confirm that the environment for the internal surfaces of the suppression chamber spray piping will be considered as a different internal environment from other normally-filled treated water piping within the One-Time Inspection Program, or provide the bases to demonstrate that such a distinction is not needed for the portion of piping that is periodically wetted and drained.*

Response:

1) The suppression chamber spray nozzles are copper alloy and the upstream connected piping is carbon steel. Corrosion and fouling of the copper alloy nozzles themselves is expected to be minimal. However, as indicated by this RAI, a potential exists for corrosion products or fouling from the upstream carbon steel piping to cause flow blockage in the copper alloy nozzles. This aging effect will be managed as follows to ensure the flow control intended function is maintained.

   As described in the response to RAI 3.2.2.2-1 (DTE letter NRC-15-0010 dated February 5, 2015), surveillance testing is performed every 92 days to verify that flow rates of at least 500 gpm are achieved through the suppression chamber spray lines. Any test results that do not achieve 500 gpm or indicate a decreasing trend in this flow rate would be investigated and corrected through the Fermi 2 Corrective Action Program. Although this surveillance testing is not described in the License Renewal Application (LRA), the testing will continue to be performed throughout the period of extended operation as it is a Technical Specification Surveillance Requirement.

   There are 12 spray nozzles in the suppression chamber. Based on the nozzle design capacity from the manufacturer and other system parameters, a total flow rate of approximately 700 gpm or greater is expected when testing flow through the nozzles. The test results for the last 4 years have all been approximately 700 gpm or greater, which indicates that flow blockage due to fouling is negligible in the spray header and nozzles. However, since the surveillance testing acceptance criteria is 500 gpm, there is a potential that the acceptance

criteria could be met even with one or more spray nozzles blocked.

To ensure that the "flow control" intended function of the suppression chamber spray nozzles will be maintained throughout the period of extended operation, periodic inspection of the spray nozzles will be performed. Since the type of spray nozzle used in the suppression chamber is identical to the type used in the drywell, the inspection will be performed in a manner similar to the air flow testing that is performed for the drywell spray nozzles. The air flow testing of the suppression chamber spray nozzles will be performed as part of the Periodic Surveillance and Preventive Maintenance (PSPM) Program described in LRA Sections A.1.35 and B.1.35. As described in LRA Sections A.1.35 and B.1.35, inspections associated with the PSPM Program occur at least once every five years during the period of extended operation. Utilizing this frequency for inspection of the suppression chamber spray nozzles is consistent with the 5-year frequency that is used for the drywell spray nozzles, as described in the response to RAI 3.2.2.2-1 (DTE letter NRC-15-0010 dated February 5, 2015).

LRA Sections A.1.35 and B.1.35 will be revised to include a description of the testing of the suppression chamber spray nozzles. The PSPM Program will be added to the list of applicable aging management programs in LRA Section 3.2.2.1.2. In addition, a line item will be added to LRA Table 3.2.2-2 to indicate that the PSPM Program will manage the "fouling" aging effect for the spray nozzles.

Regarding the new line item in LRA Table 3.2.2-2, the internal environment was selected as treated water. This is because although the interior of the nozzles is normally dry, it is periodically wetted due to the surveillance testing. Since copper alloy has no aging effect for an indoor air environment (as indicated by the existing LRA Table 3.2.2-2 line item for the external environment), only the internal environment of treated water was listed. Furthermore, note "H" was used for the new line item to indicate that the aging effect is not in NUREG-1801 for this component, material, and environment combination. LRA Table 3.2.1 Item 3.2.1-6 was not used as the Table 1 reference since the nozzle material is copper alloy rather than steel, the environment is treated water rather than air, and the flow blockage concern is mainly due to the upstream steel piping rather than the copper alloy nozzle itself.

2) Following the suppression chamber spray surveillance testing, the spray isolation valve is closed. The piping upstream of the isolation valve remains wetted and its internal environment is treated water. Therefore, the upstream piping is adequately addressed by the line item in LRA Table 3.2.2-2 to manage loss of material in carbon steel piping using the Water Chemistry Control – BWR Program and One-Time Inspection Program. The piping downstream of the isolation valve is open to the suppression chamber and is free to drain through the spray nozzles. As the piping drains, the treated water will be replaced by the suppression chamber atmosphere, which is inerted during power operation. Since this portion of piping is exposed to a wetting and drying cycle, it is reasonable to treat this portion of piping as a separate environment.

LRA Table 3.2.2-2, as revised by DTE letter NRC-15-0010 dated February 5, 2015, already contains a line item for carbon steel piping with an internal environment of treated water / gas. The One-Time Inspection Program manages the loss of material aging effect. This LRA Table 3.2.2-2 line item will be revised to include an additional plant-specific note that the One-Time Inspection Program will also be used to inspect the suppression chamber spray piping that is exposed to a wetting and drying cycle. LRA Sections A.1.33 and B.1.33 will be revised to include this activity in the inspections included in the One-Time Inspection Program.

LRA Revisions:

LRA Table 3.2.2-2 and associated plant-specific notes and LRA Sections 3.2.2.1.2, A.1.33, A.1.35, B.1.33, and B.1.35 are revised as shown on the following pages. Additions are shown in underline and deletions are shown in strike-through. Note that previous changes to these same LRA sections made in the July 30, 2014 letter (NRC-14-0051) and February 5, 2015 letter (NRC-15-0010) are not shown in underline or strike-through such that only the new changes due to RAI 3.2.2.2-1a are shown as revisions.

3.2.2.1.2 Residual Heat Removal System

Aging Management Programs

The following aging management programs manage the effects of aging on the residual heat removal system components.

- Bolting Integrity
- External Surfaces Monitoring
- One-Time Inspection
- Periodic Surveillance and Preventive Maintenance
- Service Water Integrity
- Water Chemistry Control – BWR
- Water Chemistry Control – Closed Treated Water Systems

Notes for Table 3.2.2-1 through 3.2.2-8-6

Plant-Specific Notes

206. Portions of the suppression chamber spray piping are normally dry, but wetted during periodic system testing. The internal environment of this piping may alternate between wet and dry. One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

Table 3.2.2-2
Residual Heat Removal System
Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Table 3.2.2-2: Residual Heat Removal System								
Nozzle	Pressure boundary Flow control	Copper alloy	Air – indoor (ext)	None	None	V.F.EP-10	3.2.1-57	A
Nozzle	Pressure boundary Flow control	Copper alloy	Treated water (int)	Flow blockage due to fouling	Periodic Surveillance and Preventive Maintenance	--	--	H
Nozzle	Pressure boundary Flow control	Copper alloy	Treated water (int)	Loss of material	Water Chemistry Control – BWR	VII.E3.AP-140	3.3.1-22	C, 201
Piping	Pressure boundary	Carbon steel	Treated water (int) / Gas	Loss of material	One-Time Inspection	--	--	G, 203, 206

A.1.33 One-Time Inspection Program

A representative sample of internal and external surfaces of reactor core isolation cooling (RCIC) piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
<u>A representative sample of internal surfaces of the normally dry suppression chamber spray piping that is periodically wetted by RHR system testing</u>	<u>One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.</u>

Inspections will be performed within the ten years prior to the period of extended operation.

A.1.35 Periodic Surveillance and Preventive Maintenance Program

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance Program manages aging effects not managed by other aging management programs, including loss of material, fouling, loss of material due to wear, and loss of sealing. Any indication or relevant condition of degradation detected is evaluated. Inspections occur at least once every five years during the period of extended operation.

The Periodic Surveillance and Preventive Maintenance Program also manages loss of material in carbon steel components exposed to raw water due to the recurring internal corrosion aging mechanism collectively referred to as multiple corrosion mechanisms (MCM). MCM was identified as a recurring internal corrosion aging mechanism (RICAM) in an operating experience review conducted by DTE in accordance with LR-ISG 2012-02 Section A.

The Fermi 2 aging management review credits the following inspection activities.

- Visually inspect and manually flex the rubber gasket/seal for reactor building spent fuel storage pool gates to verify no loss of sealing.
- Inspect suppression chamber spray nozzles for flow blockage using an air test.
- Determine wall thickness of selected service water system piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.

B.1.33 ONE-TIME INSPECTION

A representative sample of internal and external surfaces of RCIC piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal surfaces of the normally dry suppression chamber spray piping that is periodically wetted by RHR system testing	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

Inspections will be performed within the ten years prior to the period of extended operation.

B.1.35 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Program Description

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages aging effects not managed by other aging management programs, including loss of material, fouling, loss of material due to wear, and loss of sealing. Any indication or relevant condition of degradation detected is evaluated. Inspections occur at least once every five years during the period of extended operation.

The Periodic Surveillance and Preventive Maintenance Program also manages loss of material in carbon steel components exposed to raw water due to the recurring internal corrosion aging mechanism collectively referred to as multiple corrosion mechanisms (MCM). MCM was identified as a recurring internal corrosion aging mechanism (RICAM) in an operating experience review conducted by DTE in accordance with LR-ISG 2012-02 Section A.

The Fermi 2 aging management review credits the following inspection activities.

Reactor building	Visually inspect and manually flex the rubber gasket/seal for spent fuel storage pool gates to verify no loss of sealing.
<u>Residual heat removal system</u>	<u>Inspect suppression chamber spray nozzles for flow blockage using an air test.</u>
Service water system	Determine wall thickness of selected piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.

Set 31 RAI B.1.2-2a

Background

Licensed Renewal Application (LRA) Section B.1.2 states that the Bolting Integrity Program is an existing program, with enhancements, that will be consistent with Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.M18, "Bolting Integrity." In its response to Request for Additional Information (RAI) B.1.2-2, dated January 20, 2015, DTE stated, in part, the following:

> *Quarterly surveillance runs of the [residual heat removal service water] RHRSW, [emergency equipment service water] EESW, and [emergency diesel generator service water] EDGSW pumps are performed. The pump performance parameters are trended to determine if corrective actions are needed. Pump degradation during surveillance runs would lead to pump repair or refurbishment. During this maintenance, the associated bolting would be inspected, including the bolting threads. To ensure that loss of material in crevice locations that are not readily visible can be detected, the LRA will be revised to include these opportunistic inspections of the submerged bolting threads as part of the Bolting Integrity Program.*

Issue

GALL Report AMP XI.M18 recommends periodic inspections (at least once per refueling cycle) of closure bolting for signs of leakage to ensure the detection of age-related degradation due to loss of material and loss of preload. The staff notes that a submerged environment limits the ability to detect leakage of submerged bolted connections. Therefore, additional information is needed for the staff to understand how the Bolting Integrity Program will ensure the detection of loss of material and loss of preload and an adequate age management of bolts in the RHRSW, EESW, and EDGSW systems submerged environment.

The Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) states that the AMP frequency of inspections may be linked to plant specific or industry wide operating experience and a discussion should provide justification that the frequency is adequate to detect the aging effects before there is a loss of structure and component (SC) intended function. The SRP-LR also states that the detection of aging effects should occur before there is a loss of SC intended function. The staff is concerned about the possibility that an opportunistic inspection approach may result in inspections not done frequently enough to detect degradation of the bolt thread area of the submerged bolts before there is a loss of intended function. Therefore, it is not clear how opportunistic inspections based on pump maintenance activities will be adequate to detect loss of material in the thread region of the submerged bolts before there is a loss of intended function.

Request

1. *Provide the number of times (including year) that maintenance activities (e.g., pump repair or refurbishment) have been performed for the RHRSW, EESW, and EDGSW systems with submerged bolting.*

2. *Provide the technical basis as to how the proposed inspections will ensure that the aging effects for the threaded area of the submerged bolting will be timely detected and adequately managed before there is a loss of intended function.*

Response:

1. The submerged bolting in the service water systems is associated with the submerged RHRSW, EESW, and EDGSW pumps and piping. The maintenance history is provided for each of the systems below.

   a) RHRSW – Pumps A, B, C, and D have all been replaced one time. The replacements were performed in November 2005, July 2009, April 2010, and March 2011, respectively. No other significant repair or refurbishment of these pumps was noted. However, individual bolts in the submerged part of the system were replaced as corrective actions based on the results of periodic inspections.
   b) EESW – Pumps A and B have both been replaced one time. The replacements were performed in February 2005 and October 2006, respectively. No other significant repair or refurbishment of these pumps was noted. However, individual bolts in the submerged part of the system were replaced as corrective actions based on the results of periodic inspections.
   c) EDGSW – Pumps 11, 12, 13, and 14 have all been replaced one time. The replacements were performed in November 2008, February 2005, May 2008, and October 2007, respectively. No other significant repair or refurbishment of these pumps was noted. However, individual bolts in the submerged part of the system were replaced as corrective actions based on the results of periodic inspections.

2. As discussed in the response to RAI B.1.2-2 (DTE letter NRC-15-0006 dated January 20, 2015), aging effects on the submerged bolting are managed by a combination of activities including preventive measures (e.g. material selection, lubricant selection, appropriate preload), quarterly surveillance tests of the RHRSW, EESW, and EDGSW pumps which monitor and trend pump performance, periodic inspections of the submerged bolting, and opportunistic inspections of the bolting threads during maintenance activities.

   The periodic inspections of the submerged bolting that are currently performed, and will be performed every refueling outage during the period of extended operation, are capable of visually inspecting both bolt heads and some bolt threads in most configurations. Figure 1 on the following pages show an example of a bolting configuration prior to use. The figure shows that portions of the bolt threads protrude beyond the flange and will therefore be

visible during the inspection. Plant-specific operating experience has identified degradation in the exposed bolt heads and threads and led to the replacement of bolts under the corrective action program. Visual inspection of the degraded bolts after their removal has indicated that the worst degradation occurs on the bolt head and threads that are exposed. Photographs verifying these results are shown in Figures 2 and 3 on the following pages. As a result, the exposed bolt head and threads that are visually inspected on a periodic basis provide the leading indication of degradation and bound the condition of the bolt threads in the non-exposed, load-bearing portion of the bolts (i.e. inside the flange). For this reason, aging effects in the threaded area of the submerged bolting will be detected in a timely manner and adequately managed prior to loss of intended function. When degradation of the exposed bolting is discovered during periodic inspections, the bolting will be replaced in accordance with the corrective action program, similar to what has been done previously as described in the response to request 1 above. Each bolt replacement represents an additional opportunity to confirm the plant-specific operating experience that the exposed region of the bolt threads is the leading indication of degradation and bounds the condition of the non-exposed region.

In addition to the periodic inspections described above, the non-exposed region of the bolt threads will be inspected on an opportunistic basis per the enhancement to the Bolting Integrity Program in the previous RAI response. Based on the response to request 1 above, which shows that RHRSW, EESW, and EDGSW pumps have each had major maintenance at least once in the first 25 years of plant operation, it is expected that pump maintenance will occur again during the period of extended operation. These maintenance activities will allow for opportunistic inspections of the submerged bolting, particularly in the bolt threads in the non-exposed region, and will provide additional confirmation of the plant-specific operating experience which shows that the periodic inspections of the submerged bolting are effective to adequately manage aging effects prior to loss of intended function.

LRA Revisions:

None.

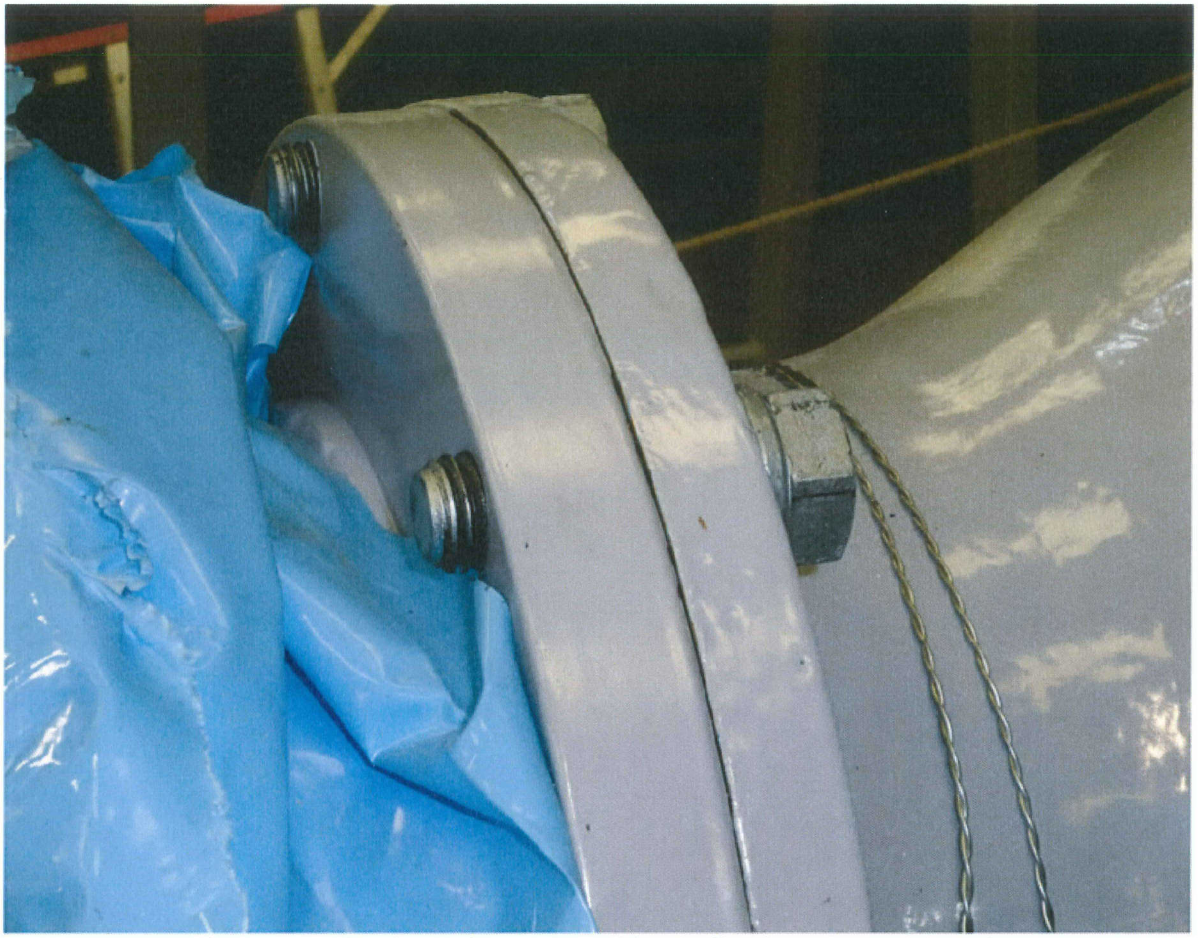

Figure 1: Bolts shown in new condition indicating exposed threads

Figure 2: Degraded bolt removed from service

Figure 3: Degraded bolt removed from service